

MURPHY OIL CORP /DE  
Form 10-K  
February 27, 2009  
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**UNITED STATES**  
**SECURITIES AND EXCHANGE COMMISSION**  
**Washington, D.C. 20549**  
**FORM 10-K**

(Mark One)

**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**  
For the fiscal year ended December 31, 2008

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**  
(State or other jurisdiction of  
incorporation or organization)

**71-0361522**  
(I.R.S. Employer  
Identification Number)

**200 Peach Street, P.O. Box 7000, El Dorado, Arkansas**  
(Address of principal executive offices)

**71731-7000**  
(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

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**Common Stock, \$1.00 Par Value  
Series A Participating Cumulative  
Preferred Stock Purchase Rights**

**New York Stock Exchange  
New York Stock Exchange**

**Securities registered pursuant to Section 12(g) of the Act: None**

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

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

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

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

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

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter (as of June 30, 2008) \$18,672,125,000.

Number of shares of Common Stock, \$1.00 Par Value, outstanding at January 31, 2009 was 190,738,655.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 13, 2009 have been incorporated by reference in Part III herein.

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**PART I**

**Item 1. BUSINESS**  
**Summary**

Murphy Oil Corporation is a worldwide oil and gas exploration and production company with refining and marketing operations in the United States and 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, the United Kingdom, Malaysia, Ecuador and all other countries. Murphy's refining and marketing activities are subdivided into geographic segments for North America and United Kingdom. Murphy exited the gasoline retailing business in Canada during 2007, but the relatively insignificant historical results for the Canadian operations have been combined with U.S. refining and marketing operations in the North American segment. Additionally, Corporate activities include interest income, interest expense, foreign exchange effects and overhead not allocated to the segments.

The information appearing in the 2008 Annual Report to Security Holders (2008 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 14 through 27, F-12 and F-13, F-30 through F-38, and F-40 of this Form 10-K report and on pages 6 and 7 of the 2008 Annual Report.

At December 31, 2008, Murphy had 8,277 employees, including 3,206 full-time and 5,071 part-time.

Interested parties may access 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 website at [www.murphyoilcorp.com](http://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 2008, 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 Ecuador, Malaysia, the Republic of the Congo, Indonesia, Australia and Suriname 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 2008 was in the United States, Canada, United Kingdom, Malaysia and Ecuador; its natural gas was produced and sold in the United States, Canada, the United Kingdom and Malaysia. MOCL owns a 5% undivided interest in Syncrude Canada Ltd. in northern Alberta, the world's largest producer of synthetic crude oil.

Murphy's worldwide crude oil, condensate and natural gas liquids production in 2008 averaged 118,254 barrels per day, an increase of 29% compared to 2007. The increase was primarily due to continued ramp up of production at the Kikeh field in Block K, offshore Sabah, Malaysia, which commenced production in August 2007. The Company's worldwide sales volume of natural gas averaged 56 million cubic feet (MMCF) per day in 2008, down 9% from 2007 levels. The lower natural gas sales volumes were primarily attributable to the sale of the Berkana Energy subsidiary in Canada in January 2008. Total worldwide 2008 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 127,507 barrels per day, up 25% compared to 2007.

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Total production in 2009 is currently expected to average approximately 180,000 barrels of oil equivalent per day. The projected production increase in 2009 is related to a combination of higher oil production at the Kikeh field, ramp-up of natural gas production during 2009 at Kikeh and the Tupper area in western Canada, both of which commenced gas production in late 2008, new oil production at the Thunder Hawk field in the Gulf of Mexico and at the Azurite field offshore the Republic of the Congo, both of which are expected to start up at mid-year 2009, and

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new gas production at fields offshore Sarawak, Malaysia, which are expected to start production in the third quarter of 2009. These volumes will more than offset anticipated field declines in 2009 at other fields in the Gulf of Mexico, onshore South Louisiana and at Hibernia and Terra Nova, offshore Newfoundland.

In the United States, Murphy has production of oil and/or natural gas from four fields operated by the Company and four main fields operated by others. The U.S. producing fields at December 31, 2008 include six in the deepwater Gulf of Mexico and two onshore in Louisiana. The Company's primary focus in the U.S. is in the deepwater Gulf of Mexico, which is generally defined as water depths of 1,000 feet or more. The Company produced approximately 10,700 barrels of oil per day and 46 million cubic feet of natural gas per day in the U.S. in 2008. These amounts represented 9% of total worldwide oil and 82% of worldwide natural gas production volumes. The Medusa field in Mississippi Canyon Blocks 538/582 is the only major field in the U.S. and represented 36% of total U.S. production on a barrel of oil equivalent basis during 2008. The Company operates and holds a 60% interest in Medusa, which produced total daily net oil and natural gas of about 5,700 barrels and 5 MMCF, respectively, in 2008. At December 31, 2008, the Medusa field has total net proved oil and natural gas reserves of approximately 7.9 million barrels and 10.3 billion cubic feet, respectively. Production from Medusa is expected to continue to decline slowly in 2009 and should average 5,200 barrels of oil and about 5 MMCF of natural gas on a daily basis. Total oil and natural gas reserves in the U.S. at December 31, 2008 were 26.8 million barrels and 97.4 billion cubic feet, respectively.

In Canada, the Company owns an interest in three significant nonoperated, long-lived assets—the Hibernia and Terra Nova fields offshore Newfoundland and Syncrude Canada Ltd. in northern Alberta. In addition, the Company owns interests in one heavy oil area and one significant natural gas area in the Western Canadian Sedimentary Basin (WCSB). Murphy has a 6.5% interest in Hibernia and a 12.0% interest in Terra Nova in the Jeanne d'Arc Basin, offshore Newfoundland. Total net production in 2008 was about 8,500 barrels of oil per day at Hibernia, while net production from Terra Nova was about 8,300 barrels of oil per day. Terra Nova production declined in 2008 due to lower gross production and a higher royalty rate. Total 2009 net oil production at Hibernia and Terra Nova is anticipated to be approximately 5,500 and 7,100 barrels per day, respectively. Total net proved oil reserves at December 31, 2008 at Hibernia and Terra Nova were approximately 8.3 million barrels and 4.3 million barrels, respectively. The joint agreement between the owners of Terra Nova requires a redetermination of working interests based on an analysis of reservoir quality among fault separated areas where varying ownership interests exist. The operator expects to complete the initial redetermination in March 2009, and the calculation is expected to be the subject of renegotiation and/or arbitration before final interests are determined. This redetermination is expected to be finalized in 2010, and is retroactive to 2005. Upon completion of the redetermination process, a cash settlement is required among partners to balance cash flows retroactive to the effective date. The Company cannot predict the final outcome of the redetermination process. 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. Total net production in 2008 was about 12,500 barrels of synthetic crude oil per day and is expected to average about 14,000 barrels per day in 2009. Although Syncrude produces a very high quality synthetic crude oil from bitumen, the SEC considers Syncrude to be a mining operation, and not a conventional oil operation and therefore, does not allow the Company to include Syncrude's reserves in its total proved oil reserves reported on page F-34. The SEC issued new reserve rules at the end of 2008 that will permit the reporting of proved reserves for synthetic oil operations beginning at year-end 2009. See further discussion at page 29 of this Form 10-K report. Total net reserves for Syncrude at year-end 2008 were approximately 131.6 million barrels. Daily net production in 2008 in the WCSB averaged about 8,500 barrels of mostly heavy oil and about 2 MMCF of natural gas. In early 2008, Murphy sold its 80% interest in Berkana Energy Corp. and in mid-2008 the Company sold its interest in the Lloydminster area of Alberta. The Company recorded a combined pretax gain from these sales of \$132.4 million in 2008. Through 2008, the Company has acquired approximately 84,000 acres of mineral rights in northeastern British Columbia in an area named Tupper. First production of natural gas occurred at Tupper in December 2008. WCSB oil and natural gas daily production in 2009 is expected to be about 5,900 barrels and 56 MMCF, with the increase in natural gas volumes due to ramp-up of production at Tupper. Total WCSB oil and gas reserves at December 31, 2008 were 11.7 million barrels and 58.4 billion cubic feet, respectively.

Murphy produces oil and natural gas in the United Kingdom sector of the North Sea. Total 2008 net production in the U.K. amounted to about 4,900 barrels of oil per day and 6 MMCF of natural gas per day, which represented 4% of oil produced and 12% of natural gas produced by the Company during the year. Total 2009 net daily production levels in the U.K. are anticipated to average 4,100 barrels of oil and 5 MMCF of natural gas. Total proved reserves in the U.K. at December 31, 2008 were 17 million barrels of oil and 20.8 billion cubic feet of natural gas.

In Malaysia, the Company has majority interests in seven separate production sharing contracts (PSCs). The Company serves as the operator of all these areas, which cover approximately 9.6 million acres. Through 2006, Murphy had an 85% interest in two shallow water blocks, SK 309 and SK 311, offshore Sarawak. In January 2007, the Company renewed the contract on these two Sarawak blocks at a 60% interest for areas with no discoveries, while retaining its 85% interest in the portion of these blocks on which discoveries have been made. The West Patricia and Congkak fields in Block SK 309 produced about 4,400 net barrels of oil per day in 2008, less than in 2007 due to a combination of lower gross production and a lower percentage of production allocated to the Company under the production sharing contract. Net oil production in 2009 at fields offshore Sarawak is anticipated to increase to about 4,800 barrels of oil per day due to liquids associated with natural gas production that is expected to start-up in the third quarter 2009. The Company has a gas sales contract for the Sarawak area with PETRONAS, the Malaysian state-owned oil company, and has prepared a multi-phase development plan for several natural gas discoveries on the block. The gas sales

contract allows for sales of up to 250 million cubic feet per day through 2014. Total net natural gas sales volume offshore

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Sarawak is anticipated to be 67 million cubic feet per day in 2009. Total proved reserves of oil and natural gas at December 31, 2008 for Blocks SK 309/311 were 9 million barrels and 298.7 billion cubic feet of natural gas. Further exploration drilling occurred in Blocks SK 309 and SK 311 in 2008, but the drilling was unsuccessful.

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. Further discoveries have been made in Block K at Senangin and Kerisi. 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 covering 1.02 million acres. The Company retained its 80% interest at Kikeh, Kakap and other discoveries in Block K. First oil production from Kikeh began in August 2007, less than five years after the initial discovery. Production volumes at Kikeh averaged 53,000 net barrels of oil per day for the full year 2008 and continued to ramp up during 2008 with new wells brought on stream during the year. Oil production at Kikeh peaked at a gross rate of 121,500 barrels per day in December 2008. Net oil production at Kikeh is anticipated to average 72,600 barrels per day for 2009. In February 2007, the Company signed a Kikeh field natural gas sales contract with PETRONAS. The contract calls for sales volumes of up to 120 million cubic feet per day through June 2012. Natural gas production at Kikeh began in late 2008, and expected production in 2009 is 66 million cubic feet per day. Total proved reserves booked in Block K as of year-end 2008 were 91.7 million barrels of oil and 106.5 billion cubic feet of natural gas. An unsuccessful wildcat well was drilled in 2008 at the Buntal prospect in Block K.

In early 2006, the Company also added a 60% interest in a new PSC for Block P, which includes 1.05 million acres of the previously relinquished Block K area. Unsuccessful wells were drilled at the Chengal and Rempah prospects in Block P in late 2008. The Company has an 80% 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, and in early 2008, the Company followed up 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 two discoveries. The Company was awarded interests in two PSCs covering deepwater Blocks L (60%) and M (70%) in 2003. The Sultanate of Brunei also claims this acreage. Murphy drilled a wildcat well in Block L in mid-2003. Well results have been kept confidential and well costs of \$12 million remain capitalized pending the resolution of the ownership issue. The Company is unable to predict when or how ownership of Blocks L and M will be resolved. A total of 2.9 million gross acres associated with Blocks L and M have been included in the acreage table below.

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 for these discoveries are being studied. Murphy relinquished its remaining interests in Block PM 311 and all of adjacent Block PM 312 in 2007.

In Ecuador, Murphy owns a 20% working interest in Block 16, which is operated by Repsol-YPF under a participation contract that expires in January 2012. The Company's net production was about 7,400 barrels of oil per day in 2008 and is expected to average about 5,800 barrels per day in 2009, with the decline expected due to no development drilling budgeted after a late 2007 government revenue sharing amendment. 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 working interest owners in Block 16 have initiated arbitration proceedings against the government claiming that they do not have a right under the contract to enforce a revenue sharing provision. The arbitration proceedings could take many months to reach conclusion. Meanwhile, the Company and its partners have been unsuccessful with negotiating a contract revision with the government, but negotiations continue. At December 31, 2008, the Company's total proved reserves for Ecuador were 4.8 million barrels.

The Company has interests in Production Sharing Agreements covering most of two offshore blocks in the Republic of the Congo—Mer Profonde Sud (MPS) and Mer Profonde Nord (MPN). The Company's interests cover approximately 1.33 million acres with water depths ranging from 490 to 6,900 feet, and the Company believes this acreage covers the most prospective portions of the blocks. Murphy drilled its first exploration well in late 2004 and in early 2005 announced an oil discovery at Azurite Marine #1 in the southern block, MPS. In 2005, the Company successfully followed up the Azurite discovery with an appraisal well that tested at 8,000 barrels of oil per day from one zone. A third well in early 2006 further appraised the Azurite area. The Company's Board of Directors approved the development of the Azurite field in late 2006. During 2008, the Company continued its development of the Azurite field, with first oil production currently anticipated in mid-2009. In late 2007, the Company sold down its interest in the MPS block, including the Azurite field, from 85% to 50%. The initial sale proceeds received were \$83.5 million with additional contingent consideration of up to \$26.5 million that can be earned upon achieving certain financial and operating goals for Azurite field development. In addition, the Company will receive a partial carry on costs for two exploration wells in MPS that are expected to be drilled in 2009. Total net oil production is anticipated to average 3,900 barrels per day for the full year 2009 based on the expected mid-year start-up.

In June 2007, Murphy entered into a production sharing contact covering Block 37, offshore Suriname. Murphy operates this block and has an 80% interest. Block 37 covers approximately 2.16 million acres and has water depths ranging from 160 to 1,000 feet. The contract provides for an initial six-year exploration phase and requires the acquisition of 3D seismic and the drilling of two wells. The seismic was shot in late 2008 and early 2009, and interpretation of this data will occur in 2009. The first wildcat well is likely to be drilled in 2010.





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The Company acquired a 40% interest and operatorship of an exploration permit covering approximately 1.00 million gross acres in Block AC/P36 in the Browse Basin offshore northwestern Australia in November 2007. Three-dimensional seismic data was obtained in late 2007 and drilling of a commitment exploration well at a prospect named Abalone Deep in late 2008 was unsuccessful. In November 2008, the Company acquired a 70% interest and operatorship of a second Browse Basin exploration permit in Block WA-423-P. This permit covers approximately 1.43 million acres and calls for a 3D seismic survey and one exploration well, which is expected to be drilled in 2011. Murphy has reached agreement in principle to farm down its interest in WA-423-P to 40%; the agreement is expected to be executed in the first quarter of 2009. The Company has opened an office in Perth, Australia to support the operations of these permits.

In May 2008, the Company entered into a production sharing contract in Indonesia covering a 100% interest in the South Barito block in south Kalimantan on the island of Borneo. The block covers approximately 1.24 million acres. 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. The contract requires relinquishment of 25% of acreage after three years and an additional 55% after six years. In November 2008, Murphy entered into a production sharing contract in the Semai II Block offshore West Papua, Indonesia. The Company has a 33% interest in the block which covers about 835,000 acres. The permit calls for a 3D seismic program and three exploration wells.

Murphy's estimated net quantities of proved oil and gas reserves and proved developed oil and gas reserves at December 31, 2005, 2006, 2007 and 2008 by geographic area are reported on pages F-34 and F-35 of this Form 10-K report. Murphy has not filed and is not required to file any estimates of its total net 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 net proved reserves of such properties are determined.

Net crude oil, condensate and gas liquids production and sales, and net natural gas sales by geographic area with weighted average sales prices for each of the seven years ended December 31, 2008 are shown on page 6 of the 2008 Annual Report. In 2008, the Company's production of oil and natural gas represented approximately 0.1% of the respective worldwide totals.

Production expenses for the last three years in U.S. dollars per equivalent barrel are discussed on page 19 of this Form 10-K report. For purposes of these computations, natural gas sales volumes are converted to equivalent barrels of crude oil using a ratio of six thousand cubic feet (MCF) of natural gas to one barrel of crude oil.

Supplemental disclosures relating to oil and gas producing activities are reported on pages F-32 through F-40 of this Form 10-K report.

At December 31, 2008, 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.

| Area (Thousands of acres) | Developed |     | Undeveloped |       | Total |       |
|---------------------------|-----------|-----|-------------|-------|-------|-------|
|                           | Gross     | Net | Gross       | Net   | Gross | Net   |
| United States Onshore     | 3         | 2   | 190         | 118   | 193   | 120   |
| Gulf of Mexico            | 13        | 5   | 1,231       | 796   | 1,244 | 801   |
| Alaska                    | 4         | 1   | 3           |       | 7     | 1     |
| Total United States       | 20        | 8   | 1,424       | 914   | 1,444 | 922   |
| Canada Onshore            | 24        | 15  | 285         | 256   | 309   | 271   |
| Offshore                  | 88        | 8   | 45          | 3     | 133   | 11    |
| Total Canada              | 112       | 23  | 330         | 259   | 442   | 282   |
| United Kingdom            | 33        | 4   | 40          | 6     | 73    | 10    |
| Malaysia                  | 7         | 6   | 9,628       | 6,126 | 9,635 | 6,132 |
| Ecuador                   | 7         | 1   | 524         | 105   | 531   | 106   |
| Republic of the Congo     |           |     | 1,333       | 902   | 1,333 | 902   |
| Suriname                  |           |     | 2,164       | 1,731 | 2,164 | 1,731 |

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|           |          |  |  |       |       |        |        |
|-----------|----------|--|--|-------|-------|--------|--------|
| Australia |          |  |  | 2,432 | 1,402 | 2,432  | 1,402  |
| Indonesia |          |  |  | 2,077 | 1,368 | 2,077  | 1,368  |
| Spain     |          |  |  | 36    | 6     | 36     | 6      |
| Totals    |          |  |  | 179   | 42    | 19,988 | 12,819 |
| Oil sands | Syncrude |  |  | 96    | 5     | 160    | 8      |
|           |          |  |  |       |       | 256    | 13     |

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Net acreage expirations in 2010 include 1,133 thousand net acres in Blocks SK 309/311 in Malaysia and 1,913 thousand net acres in Blocks L and M Malaysia. As discussed more fully on page 3, Blocks L and M are also claimed by the Sultanate of Brunei. Scheduled expirations in 2011 include 401 thousand net acres in Block AC/P36, Australia; 447 thousand acres in South Barito and 88 thousand net acres in Semai II in Indonesia; 346 thousand net acres in Block 37 Suriname; 563 thousand net acres in Block K Malaysia; and 336 thousand net acres in Blocks MPS and MPN in the Republic of the Congo.

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, 2008.

| Country        | Oil Wells |     | Gas Wells |     |
|----------------|-----------|-----|-----------|-----|
|                | Gross     | Net | Gross     | Net |
| United States  | 38        | 8   | 14        | 6   |
| Canada         | 306       | 186 | 57        | 48  |
| United Kingdom | 34        | 3   | 24        | 2   |
| Malaysia       | 28        | 23  |           |     |
| Ecuador        | 156       | 31  |           |     |
| Totals         | 562       | 251 | 95        | 56  |

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

|             | United States |     | Canada     |      | United Kingdom |     | Malaysia   |     | Ecuador and Other |     | Totals     |      |
|-------------|---------------|-----|------------|------|----------------|-----|------------|-----|-------------------|-----|------------|------|
|             | Productive    | Dry | Productive | Dry  | Productive     | Dry | Productive | Dry | Productive        | Dry | Productive | Dry  |
| <b>2008</b> |               |     |            |      |                |     |            |     |                   |     |            |      |
| Exploratory | 1.7           | 1.5 |            |      | .2             |     | .8         | 4.6 |                   |     | 2.7        | 6.1  |
| Development | .8            |     | 64.4       | 1.0  | .2             | .1  | 9.9        |     | .4                |     | 75.7       | 1.1  |
| <b>2007</b> |               |     |            |      |                |     |            |     |                   |     |            |      |
| Exploratory | 0.8           | 3.0 | 0.3        |      |                |     | 0.8        | 0.8 |                   |     | 1.9        | 3.8  |
| Development | 1.4           |     | 47.2       | 9.2  | 0.2            | 0.1 | 5.6        |     | 5.0               |     | 59.4       | 9.3  |
| <b>2006</b> |               |     |            |      |                |     |            |     |                   |     |            |      |
| Exploratory | 0.8           | 1.4 |            |      |                |     | 11.8       | 3.4 | 1.0               | 0.2 | 13.6       | 5.0  |
| Development |               |     | 61.5       | 24.8 | 0.1            |     | 2.4        |     | 5.2               |     | 69.2       | 24.8 |

Murphy's drilling wells in progress at December 31, 2008 are shown below.

| Country        | Exploratory |     | Development |     | Total |     |
|----------------|-------------|-----|-------------|-----|-------|-----|
|                | Gross       | Net | Gross       | Net | Gross | Net |
| United States  | 1.0         | .6  | 2.0         | .7  | 3.0   | 1.3 |
| Canada         |             |     | 2.0         | .1  | 2.0   | .1  |
| United Kingdom |             |     | 1.0         | .1  | 1.0   | .1  |
| Australia      | 1.0         | .4  |             |     | 1.0   | .4  |
| Malaysia       |             |     | 1.0         | .9  | 1.0   | .9  |
| Totals         | 2.0         | 1.0 | 6.0         | 1.8 | 8.0   | 2.8 |

**Refining and Marketing**

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The Company's refining and marketing businesses are located in the United States and the United Kingdom, and primarily consist 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.

Murphy Oil USA, Inc. (MOUSA), a wholly owned subsidiary of Murphy Oil Corporation, owns and operates two refineries in the United States. The larger of its U.S. refineries is at Meraux, Louisiana, on the Mississippi River approximately 10 miles southeast of New Orleans. The refinery is located on fee land. The Company's refinery at Superior, Wisconsin is also located on fee land. Murco Petroleum Limited (Murco), a wholly owned U.K. subsidiary, owns 100% interest in a refinery at Milford Haven, Wales. Murco acquired the remaining 70% of the Milford Haven refinery that it did not already own on December 1, 2007 and now fully operates the facility, which is primarily located on fee land.

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Refinery capacities at December 31, 2008 are shown in the following table.

|  | Meraux,<br>Louisiana | Superior,<br>Wisconsin | Milford Haven,<br>Wales | Total      |
|--|----------------------|------------------------|-------------------------|------------|
| Crude capacity b/sd*                           | 125,000              | 35,000                 | 108,000                 | 268,000    |
| Process capacity b/sd*                         |                      |                        |                         |            |
| Vacuum distillation                            | 50,000               | 20,500                 | 55,000                  | 125,500    |
| Catalytic cracking fresh feed                  | 37,000               | 11,000                 | 37,000                  | 85,000     |
| Naphtha hydrotreating                          | 35,000               | 10,500                 | 18,300                  | 63,800     |
| Catalytic reforming                            | 32,000               | 8,000                  | 18,300                  | 58,300     |
| Gasoline hydrotreating                         |                      | 7,500                  |                         | 7,500      |
| Distillate hydrotreating                       | 52,000               | 11,800                 | 74,000                  | 137,800    |
| Hydrocracking                                  | 32,000               |                        |                         | 32,000     |
| Gas oil hydrotreating                          | 12,000               |                        |                         | 12,000     |
| Solvent deasphalting                           | 18,000               |                        |                         | 18,000     |
| Isomerization                                  |                      |                        | 11,300                  | 11,300     |
| Production capacity b/sd*                      |                      |                        |                         |            |
| Alkylation                                     | 8,500                | 1,500                  | 6,300                   | 16,300     |
| Asphalt  |                      | 7,500                  |                         | 7,500      |
| Crude oil and product storage capacity barrels | 3,140,000            | 3,085,000              | 8,908,000               | 15,133,000 |

\* Barrels per stream day.

In late August 2005, the Meraux, Louisiana refinery was severely damaged by flooding and high winds caused by Hurricane Katrina. The Meraux refinery was shut-down for repairs for about nine months following the hurricane and restarted in mid-2006. The majority of costs to repair the Meraux refinery are expected to be covered by insurance. Oil Insurance Limited (O.I.L.), the Company's primary property insurance coverage, has informed insureds that it has currently estimated that recoveries for Hurricane Katrina damages will likely be no more than 46% of claimants' eligible losses. Murphy has other commercial insurance coverage for repair costs not covered by O.I.L., but this coverage limits recoveries from flood damage to \$50.0 million. Costs to repair the refinery were approximately \$196.0 million. Based on the expected insurance recoveries and repair costs as described, the Company recorded expenses for repair costs not recoverable from insurance of \$50.7 million in 2006 and a further \$3.0 million in 2007. The final settlement and recovery of insurance could take several years to complete. At December 31, 2008, total receivables from insurance companies related to hurricane repairs at Meraux was \$26.5 million.

In 2003, Murphy expanded the Meraux refinery allowing the refinery to meet low-sulfur gasoline specifications which became effective January 1, 2008. The expansion included a new hydrocracker unit, central control room and two new utility boilers; expansion of the crude oil processing capacity to 125,000 barrels per stream day (b/sd); expansion of naphtha hydrotreating capacity to 35,000 b/sd; expansion of the catalytic reforming capacity to 32,000 b/sd; and construction of a new sulfur recovery complex, including amine regeneration, sour water stripping and high efficiency sulfur recovery. During 2004 the Company also completed the addition of a fluid catalytic cracking gasoline hydrotreater unit at its Superior, Wisconsin refinery, that allows the refinery to meet low-sulfur gasoline specifications. In 2006, the isomerization unit at the Superior refinery was revamped to a hydrotreater and one of two existing naphtha hydrotreaters was revamped to a kerosene hydrotreater.

MOUSA markets refined products through a network of retail gasoline stations and branded and unbranded wholesale customers in a 24-state area of the southern and midwestern United States. Murphy's retail stations are primarily located in the parking lots of Walmart Supercenters in 21 states and use the brand name Murphy USA®. The Company also markets gasoline and other products at stand-alone stations under the Murphy Express® brand. Branded wholesale customers use the brand name SPUR®. Refined products are supplied from 12 terminals that are wholly owned and operated by MOUSA and numerous terminals owned by others. Of the wholly owned terminals, three are supplied by marine transportation, three are supplied by truck, four are supplied by pipeline and two are adjacent to MOUSA's refineries. The Company opened a newly built finished products terminal near Jonesboro, Arkansas in 2007. MOUSA also receives products at terminals owned by others either in exchange for deliveries from the Company's terminals or by outright purchase. At December 31, 2008, the Company marketed products through 1,025 Murphy owned and operated stations and 129 branded wholesale SPUR stations. Of the Company stations, 992 are located on parking lots of Walmart Supercenters and 33 are stand-alone Murphy Express locations. MOUSA plans to build additional retail gasoline stations at Walmart Supercenters and other stand-alone locations in 2009.



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During 2007, the Company agreed to buy the land underlying most of the stations on Walmart parking lots from Walmart. Through 2008, the Company had acquired 835 sites from Walmart. No further rent is payable to Walmart for the purchased locations. For the remaining gasoline stations located on Walmart property that were not acquired from Walmart, 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 42.3% of consolidated Company revenues in 2008, 48.8% in 2007 and 51.7% in 2006. As the Company continues to expand the number of retail operated gasoline stations, total revenue generated by this business is expected to grow.

Murphy owns a 20% interest in a 120-mile refined products pipeline, with a capacity of 165,000 barrels per day, that transports products from the Meraux refinery to two common carrier pipelines serving the southeastern United States. The Company also owns a 3.2% interest in the Louisiana Offshore Oil Port LLC (LOOP), which provides deepwater unloading accommodations off the Louisiana coast for oil tankers and onshore facilities for storage of crude oil. A crude oil pipeline with a diameter of 24 inches connects LOOP storage 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. This crude oil pipeline is connected to another company's pipeline system, allowing crude oil transported by that system to also be shipped to the Meraux refinery.

At the end of 2008, Murco distributed refined products in the United Kingdom from the wholly-owned Milford Haven refinery, three wholly owned terminals supplied by rail, seven terminals owned by others where products are received in exchange for deliveries from the Company's terminals and five terminals owned by others where products are purchased for delivery. There are 231 Company stations, 112 of which are branded MURCO with the remainder under various third party brands. The Company owns the freehold under 157 of the sites and leases the remainder. The Company supplies 223 MURCO branded dealer stations.

In 2008, Murphy owned approximately 1.0% of the crude oil refining capacity in the United States and 5.9% of the refining capacity in the United Kingdom. The Company's market share of U.S. retail gasoline sales was approximately 2.6% in 2008 and in the U.K. our fuel sales represented 1.6% of the total market share.

A statistical summary of key operating and financial indicators for each of the seven years ended December 31, 2008 are reported on page 7 of the 2008 Annual Report.

## **Environmental**

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

Further information on environmental matters and their impact on Murphy are contained in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 25 through 27.

## **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 companies. Virtually all of the state-owned and major integrated oil companies and many of the independent producers and refiners that compete with the

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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 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 found 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 crude oil and natural gas reserves included in this report on pages F-34 and F-35 have been prepared by Company personnel and outside experts based on oil and natural gas prices in effect at the end of each year as well as other conditions and information available at the time the estimates were prepared. Estimation of reserves is a subjective process that involves professional judgment by engineers about volumes to be recovered in future periods from underground 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.

Future changes in crude oil and natural gas prices may have a material effect on the reported quantity of our proved reserves and the standardized measure of discounted future cash flows relating to proved reserves. Future reserve revisions could also occur as a result of changes in other factors such as governmental regulations.

The Company's proved undeveloped reserves and non-producing proved developed reserves represent significant portions of total proved reserves. As of December 31, 2008, approximately 29% of the Company's proved oil reserves and 64% 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. Proved undeveloped reserves have inherently more risk than proved developed reserves, generally due to significant development work which is both costly and uncertain as to timing of completion prior to the start of production. Also, at December 31, 2008, the Company's non-producing proved developed reserves represent approximately 11% of the Company's total proved reserves on a barrel of oil equivalent basis. These non-producing proved developed reserves are primarily in the U.S. Gulf of Mexico and generally represent behind pipe reserves that will require an uphole recompletion to produce the more shallow oil or natural gas reservoir. These behind pipe reserves have more risk than producing proved developed reserves.

The discounted future net revenues from our proved reserves 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 generally on prices and costs as of year-end, while actual future prices and costs may be materially higher or lower. 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.

### **The 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, natural gas and refined products that it produces. The Company's income in 2008 was favorably affected by high crude oil and natural gas prices. In the second half of 2008, crude oil prices began to fall precipitously. Although West Texas Intermediate (WTI) crude oil prices averaged about \$99 per barrel for all 2008, the year-end 2008 price for WTI was below \$45 per barrel. The Company's results of operations are negatively impacted by low oil and natural gas prices. In addition, the Company's net income could be adversely affected by lower future refining and marketing margins. 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.

**The results of exploration drilling 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 2008, significant wildcat wells were primarily drilled offshore Malaysia, offshore Australia and in the U.S. Gulf of Mexico. The Company's 2009 budget calls for wildcat drilling primarily in the Gulf of Mexico, and in waters offshore Malaysia and the Republic of the Congo.

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**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. 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. The Company's primary current financing facility expires in June 2012.

**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. An economic slowdown in late 2008 and early 2009 has had a detrimental effect on the worldwide demand for these energy commodities, which effectively led to reduced prices for oil, natural gas and refined products. 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, and also purchases refined products, particularly gasoline, needed to supply its 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 such as those experienced in 2008 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. During 2008, approximately 42% of the Company's total production was at fields operated by others, while at December 31, 2008, approximately 30% of the Company's total proved reserves were at fields operated by others. Therefore, Murphy does not fully control all activities at certain of its significant revenue generating properties.

**The operations and earnings of Murphy 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, 2008, approximately 43% 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 (See the caption "Environmental Matters" beginning on page 25 of this Form 10-K report), 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.

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

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and Rita in 2005. Additionally, the Company's largest refinery is located about 10 miles southeast of New Orleans, Louisiana. In August 2005, Hurricane Katrina passed near the refinery causing major flooding and severe wind damage. The gradual loss of coastal wetlands in southeast Louisiana increases the risk of future flooding should storms such as Katrina recur. Other assets such as gasoline terminals and certain retail gasoline stations also lie near the Gulf of Mexico coastlines and are vulnerable to storm damages. During the repairs at Meraux following Hurricane Katrina, the refinery took steps to try to reduce the potential for damages from future storms of similar magnitude. For example, certain key equipment such as motors and pumps were raised above ground level when feasible. These steps may somewhat reduce the damages associated with windstorm and major flooding that could occur with a future storm similar in strength to Katrina, but the risks from such a storm are not eliminated. Although the Company also maintains insurance for such risks as described below, due to policy deductibles and possible coverage limits, weather-related risks are not fully insured.

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**There can be no assurance that Murphy's insurance will be adequate to offset costs associated with certain events or 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, and such insurance is believed to be reasonable for the hazards and risks faced by the Company. As of December 31, 2008, the Company maintained total excess liability insurance with limits of \$775 million per occurrence covering certain general liability and certain sudden and accidental environmental risks. The Company also maintained insurance coverage with an additional limit of \$250 million per occurrence, all or part of which could be applicable to certain sudden and accidental pollution events. The occurrence of an event that is 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. The Company does not expect to fully recover repair costs incurred at Meraux under its insurance policies. Damages incurred by the Company from 2008 hurricanes did not exceed deductible limits under the insurance policies. See Note Q 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 most significant of these matters are addressed in more detail in Item 3 beginning on page 11 of this Form 10-K report.

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

Although Murphy limits its credit risk by selling its products to numerous entities worldwide, it still, at times, carries substantial credit risk from its customers. For certain oil and gas properties operated by the Company, other companies which own partial interests may not be able to meet their financial obligation to pay for their share of capital and operating costs as they come due.

**The 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 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, 2008.

### **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-32 to F-40 and in Note D Property, Plant and Equipment on page F-12.

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**Executive Officers of the Registrant**

The age at January 1, 2009, 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 51; 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, President of Murphy Exploration & Production Company-International from March 2003 through December 2006 and Senior Vice President of Frontier Exploration & Production from April 1999 through February 2003.

Steven A. Cossé Age 61; Executive Vice President since February 2005 and General Counsel since August 1991. Mr. Cossé was elected Senior Vice President in 1994 and Vice President in 1993.

Harvey Doerr Age 50; Executive Vice President responsible for the Company's worldwide refining and marketing operations effective January 1, 2007. Mr. Doerr served as President of Murphy Oil Company Ltd. from September 1997 through December 2006.

Kevin G. Fitzgerald Age 53; Senior Vice President and Chief Financial Officer since January 1, 2007. He served as Treasurer from July 2001 through December 2006 and was Director of Investor Relations from 1996 through June 2001.

Bill H. Stobaugh Age 57; Senior Vice President since February 2005. Mr. Stobaugh joined the Company as Vice President in 1995.

Mindy K. West Age 39; Vice President and Treasurer since January 1, 2007. Ms. West was Director of Investor Relations from July 2001 through December 2006.

John W. Eckart Age 50; Vice President and Controller since January 1, 2007. Mr. Eckart served as Controller since March 2000.

Walter K. Compton Age 46; Vice President since February 2009 and Secretary since December 1996.

**Item 3. LEGAL PROCEEDINGS**

On September 9, 2005, a class action lawsuit was filed in federal court in the Eastern District of Louisiana seeking unspecified damages to the class comprised of residents of St. Bernard Parish caused by a release of crude oil at Murphy Oil USA, Inc.'s (a wholly-owned subsidiary of Murphy Oil Corporation) Meraux, Louisiana, refinery as a result of flood damage to a crude oil storage tank following Hurricane Katrina. Additional class action lawsuits were consolidated with the first suit into a single action in the U.S. District Court for the Eastern District of Louisiana. In September 2006, the Company reached a settlement with class counsel and on October 10, 2006, the court granted preliminary approval of a class action Settlement Agreement. A Fairness Hearing was held January 4, 2007 and the court entered its ruling on January 30, 2007 approving the class settlement. The majority of the settlement of \$330 million will be paid by insurance. The Company recorded an expense of \$18 million in 2006 related to settlement costs not expected to be covered by insurance. As part of the settlement, all properties in the class area received a fair and equitable cash payment and have had residual oil cleaned. As part of the settlement, the Company offered to purchase all properties in an agreed area adjacent to the west side of the Meraux refinery; these property purchases and associated remediation have been paid by the Company at a cost of \$55 million. As of December 31, 2008, the Company has fulfilled its obligations under the Class Action Settlement Agreement. Approximately 40 non-class action suits regarding the oil spill have been filed and remain pending. The Company believes that insurance coverage exists and it does not expect to incur significant costs associated with this litigation. On August 14, 2007, four of the Company's high level excess insurers notified the Company for arbitration in London. The insurers do not deny coverage, but seek arbitration as to whether and to what extent expenditures made by the Company in resolving the oil spill litigation have reached the attachment point for covered loss under their respective policies. The Company is of the position that full coverage should be afforded. Accordingly, the Company believes neither the ultimate resolution of the remaining litigation nor the insurance arbitration will have a material adverse effect on its net income, financial condition or liquidity in a future period.

On June 10, 2003, a fire severely damaged the Residual Oil Supercritical Extraction (ROSE) unit at the Company's Meraux, Louisiana refinery. The ROSE unit recovers feedstock from the heavy fuel oil stream for conversion into gasoline and diesel. Subsequent to the fire, numerous class action lawsuits have been filed seeking damages for area residents. All the lawsuits have been administratively consolidated into a single legal action in St. Bernard Parish, Louisiana, except for one such action which was filed in federal court. Additionally, individual residents of Orleans Parish, Louisiana, have filed an action in that venue. On May 5, 2004, plaintiffs in the consolidated action in St. Bernard Parish amended their petition to include a direct action against certain of the Company's liability insurers. The St. Bernard Parish action has since been removed to

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federal court, which issued an order on July 25, 2008 denying plaintiff's request to certify the case as a class action. In responding to this direct action, one of the Company's insurers, AEGIS, has raised lack of coverage as a defense. The Company believes that this contention lacks merit and has been advised by counsel that the applicable policy does provide coverage for the underlying incident.



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Because the Company believes that insurance coverage exists for this matter, it does not expect to incur any significant costs associated with the lawsuits. Accordingly, the Company continues to believe that the ultimate resolution of the June 2003 ROSE fire litigation will not have a material adverse effect on its net income, financial condition or liquidity in a future period.

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

**Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS**

No matters were submitted to a vote of security holders during the fourth quarter of 2008.

**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 2,564 stockholders of record as of December 31, 2008. Information as to high and low market prices per share and dividends per share by quarter for 2008 and 2007 are reported on page F-41 of this Form 10-K report.

**SHAREHOLDER RETURN PERFORMANCE PRESENTATION**

The following line graph is furnished with this Form 10-K and presents a comparison of the cumulative five-year shareholder returns (including the reinvestment of dividends) for the Company, the Standard & Poor's 500 Stock Index (S&P 500 Index) and the AMEX 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.

|                        | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
|------------------------|------|------|------|------|------|------|
| Murphy Oil Corporation | 100  | 125  | 169  | 161  | 271  | 144  |
| S&P 500 Index          | 100  | 111  | 116  | 135  | 142  | 90   |
| AMEX Oil Index         | 100  | 132  | 184  | 226  | 302  | 195  |

**Table of Contents****Item 6. SELECTED FINANCIAL DATA**

| <i>Thousands of dollars except per share data)</i> | 2008          | 2007       | 2006       | 2005       | 2004      |
|--|---------------|------------|------------|------------|-----------|
| <b>Results of Operations for the Year</b>          |               |            |            |            |           |
| Sales and other operating revenues                 | \$ 27,440,834 | 18,423,771 | 14,279,325 | 11,680,079 | 8,299,147 |
| Net cash provided by continuing operations         | 3,039,912     | 1,740,420  | 975,478    | 1,240,382  | 1,043,049 |
| Income from continuing operations                  | 1,739,986     | 766,529    | 644,669    | 846,193    | 500,208   |
| Net income   | 1,739,986     | 766,529    | 644,669    | 854,742    | 705,128   |
| Per Common share diluted                           |               |            |            |            |           |
| Income from continuing operations                  | 9.06          | 4.01       | 3.41       | 4.50       | 2.68      |
| Net income   | 9.06          | 4.01       | 3.41       | 4.55       | 3.77      |
| Cash dividends per Common share                    | .875          | .675       | .525       | .45        | .425      |
| Percentage return on                               |               |            |            |            |           |
| Average stockholders equity                        | 29.1          | 16.8       | 16.8       | 28.0       | 30.7      |
| Average borrowed and invested capital              | 24.4          | 13.9       | 14.4       | 23.5       | 21.6      |
| Average total assets                               | 15.1          | 8.5        | 9.3        | 14.6       | 13.4      |
| <b>Capital Expenditures for the Year</b>           |               |            |            |            |           |
| Continuing operations                              |               |            |            |            |           |
| Exploration and production                         | \$ 1,935,295  | 1,780,743  | 1,082,756  | 1,091,954  | 839,182   |
| Refining and marketing                             | 426,156       | 572,458    | 173,400    | 202,401    | 134,706   |
| Corporate and other                                | 3,235         | 4,146      | 6,383      | 35,476     | 1,505     |
|  | 2,364,686     | 2,357,347  | 1,262,539  | 1,329,831  | 975,393   |
| Discontinued operations                            |               |            |            |            | 9,065     |
|  | \$ 2,364,686  | 2,357,347  | 1,262,539  | 1,329,831  | 984,458   |
| <b>Financial Condition at December 31</b>          |               |            |            |            |           |
| Current ratio                                      | 1.51          | 1.37       | 1.61       | 1.43       | 1.35      |
| Working capital                                    | \$ 958,818    | 777,530    | 795,986    | 551,938    | 424,372   |
| Net property, plant and equipment                  | 7,727,718     | 7,109,822  | 5,106,282  | 4,374,229  | 3,685,594 |
| Total assets                                       | 11,149,098    | 10,535,849 | 7,483,161  | 6,410,396  | 5,498,903 |
| Long-term debt                                     | 1,026,222     | 1,516,156  | 840,275    | 609,574    | 613,355   |
| Stockholders equity                                | 6,278,945     | 5,066,174  | 4,121,273  | 3,522,070  | 2,702,632 |
| Per share  | 32.92         | 26.70      | 21.97      | 18.94      | 14.68     |
| Long-term debt percent of capital employed         | 14.0          | 23.0       | 16.9       | 14.8       | 18.5      |

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**Table of Contents****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 refining and marketing operations in the United States and 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 primarily by selling oil and natural gas production and refined petroleum products to customers at hundreds of locations in the United States, Canada, the United Kingdom, Malaysia and other countries. 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 refinery feedstocks, natural gas is purchased for fuel at its refineries and oil fields, 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.

Worldwide oil and North American natural gas prices were significantly higher in 2008 than in 2007. The average price for a barrel of West Texas Intermediate crude oil in 2008 was \$98.90, an increase of 37% compared to 2007. The NYMEX natural gas price in 2008 averaged \$8.89 per million British Thermal Units (MMBTU), up 25% from 2007. Crude oil and natural gas prices generally rose during the first half of 2008 with oil prices reaching their high in July. Both crude oil and North American natural gas prices have fallen precipitously near the end of 2008 and remain soft in early 2009. 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 93% of the total hydrocarbons produced on an energy equivalent basis by the Company in 2008. In 2009, the percentage of hydrocarbon production represented by oil is expected to decline to about 78% due to new natural gas fields at Kikeh and Block SK 309 in Malaysia and Tupper in British Columbia. If the prices for crude oil and natural gas remain weak in 2009 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.

**Results of Operations**

The Company had net income in 2008 of \$1.74 billion, \$9.06 per diluted share, compared to net income in 2007 of \$766.5 million, \$4.01 per diluted share. In 2006 the Company's net income was \$644.7 million, \$3.41 per diluted share. The significant increase in 2008 net income compared to 2007 was caused by higher earnings in the exploration and production operations, primarily due to higher sales prices for the Company's oil and natural gas production, higher crude oil production volumes and gains on disposal of two assets in Canada. The earnings for the Company's refining and marketing operations were an annual record in 2008 and improved from 2007, primarily in the U.K. and mostly caused by the December 2007 purchase of 70% of the Milford Haven, Wales refinery. The net cost of corporate activities not allocated to the operating segments was higher in 2008 than in 2007. The net income improvement in 2007 compared to 2006 primarily related to higher earnings generated by both the exploration and production and refining and marketing businesses, but partially offset by higher net costs for corporate activities. Further explanations of each of these variances are found in the following sections.

**2008 vs. 2007** Net income in 2008 was \$1.74 billion, \$9.06 per diluted share, compared to \$766.5 million, \$4.01 per diluted share, in 2007. The consolidated net income improvement of \$973.5 million in 2008 was attributable to higher earnings in both exploration and production (E&P) and refining and marketing (R&M) operations. The net cost of corporate activities in 2008 was higher than in 2007, partially offsetting the improved results in E&P and R&M. Earnings in the E&P business were markedly improved in 2008, increasing by \$942.8 million compared to 2007, as this business benefited from both higher sales prices for oil and natural gas, higher sales volumes for crude oil and gains from asset dispositions. E&P earnings were unfavorably affected in 2008 compared to 2007 by lower sales volumes for natural gas and higher expenses for exploration, production, depreciation, depletion and administration. The R&M business generated record profits in 2008, increasing \$108.1 million compared to 2007. The improvement was primarily due to refining profits generated in the U.K. in the current year following the acquisition of the remaining 70% of the Milford Haven, Wales, refinery in December 2007. R&M earnings in 2007 included an unfavorable impact from noncash inventory revaluations. Following the Milford Haven acquisition, the Company's U.K. operations recorded an after-tax noncash last-in, first-out accounting charge of \$59.5 million in 2007 to reduce the carrying value of crude oil and refined products inventory to beginning of year prices, which were significantly lower than at the end of the year. The net costs of corporate activities increased by \$77.4 million in 2008 compared to 2007, with the cost increase mostly attributable to higher losses on transactions denominated in foreign currencies and higher net expenses for interest and administration. The foreign currency losses occurred because the U.S. dollar generally strengthened against other significant foreign currencies used in the Company's business in 2008, especially compared to the British pound sterling. The higher net interest expense was mostly caused by lower interest capitalized to E&P development projects. The 2008 period included higher

corporate administrative costs mostly due to higher expense for employee compensation and community and other support activities.

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Sales and other operating revenues were \$9.0 billion higher in 2008 than in 2007 mostly due to higher sales prices and sales volumes for gasoline and other refined products, higher sales prices and sales volumes for crude oil produced by the Company, and higher revenues from merchandise sales at retail gasoline stations. Sales prices for natural gas were higher in 2008 than 2007, but the favorable price variance was somewhat offset by lower natural gas sales volumes in the current year. Gain/(loss) on sales of assets in 2008 was \$134.1 million higher than in 2007 and these realized pretax gains were primarily associated with the sales of its interests in Berkana Energy and the Lloydminster area heavy oil properties in Canada. Interest and other income was lower by \$77.7 million in 2008 due primarily to greater losses on foreign currency exchange, which in the current year was mostly attributable to a generally stronger U.S. dollar compared to the British pound sterling. Crude oil and product purchases expense increased by \$6.8 billion in 2008 compared to 2007 due to a combination of higher purchase prices and throughput volumes of crude oil and other feedstocks at the Company's refineries, higher prices and volumes of refined petroleum products purchased for sale at retail gasoline stations, and higher levels of merchandise purchased for sale at the gasoline stations. The higher crude oil purchase volumes in 2008 were caused by a full year of operations at the Milford Haven, Wales refinery in 2008 following the December 2007 purchase of the remaining 70% interest. Operating expenses increased by \$376.5 million in 2008 compared to 2007 and included higher refinery and retail station costs, and higher costs for oil field operations in Malaysia and synthetic oil operations at Syncrude. Refining costs increased due to both higher natural gas and other fuel costs and the full year of operations at Milford Haven following the 2007 acquisition. Exploration expenses were \$141.3 million higher in 2008 than in 2007 and were primarily associated with higher leasehold amortization expenses at the Tupper area in British Columbia, more dry hole expense in Malaysia and Australia, and higher geophysical expenses in Suriname. Additionally, 2007 included costs for settlement of two work commitments on leases formerly held on the Scotian Shelf offshore eastern Canada. Selling and general expenses were \$0.5 million higher in 2008 than in 2007. Depreciation, depletion and amortization expense was \$223.2 million higher in 2008 compared to 2007 due mostly to higher crude oil production volumes, but also due to higher barrel-equivalent unit rates for depreciation for virtually all E&P segments and higher depreciation for the Milford Haven, Wales refinery acquired in December 2007. Impairment of long-lived assets of \$40.7 million in 2007 primarily related to closing 55 underperforming gasoline stations in the U.S. and Canada. Accretion of asset retirement obligations increased by \$8.2 million in 2008 due to additional abandonment obligations incurred as additional Kikeh development wells were drilled during the year and higher estimated costs of future abandonment obligations at Syncrude. Net costs associated with hurricanes of \$3.0 million in 2007 was due to a downward adjustment of anticipated insurance recoveries at the Meraux refinery following Hurricane Katrina based on updated loss limits communicated in 2007 by the Company's primary property insurer. Interest expense incurred in 2008 was \$0.4 million less than in 2007 due to lower average debt levels during 2008 compared to the prior year. The amount of interest costs capitalized to property, plant and equipment decreased by \$18.4 million in 2008 due to lower levels of interest allocable to worldwide E&P development projects. Minority interest was insignificant and was associated with the operations of Berkana Energy in Canada that was sold in January 2008. Income tax expense was \$607.9 million higher in 2008 than in 2007 and was mainly attributable to a higher level of pretax earnings. The effective income tax rate for consolidated earnings increased from 38.0% in 2007 to 38.3% in 2008. The tax rate in both years was 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 exceed 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 uncertain ability of the Company to obtain tax benefits for these costs in future years.

**2007 vs. 2006** Net income in 2007 was \$766.5 million, \$4.01 per diluted share, compared to \$644.7 million, \$3.41 per diluted share, in 2006. The improvement in consolidated net income in 2007 of \$121.8 million compared to 2006 was primarily related to higher earnings in both major businesses—E&P and R&M. The net costs of corporate activities were higher in 2007 and partially offset the improved results in E&P and R&M. Earnings in the E&P business improved by \$40.3 million in 2007 as this business benefited from higher oil sales prices, lower exploration expenses and lower income taxes in 2007 compared to 2006. E&P earnings were adversely affected in 2007 by lower sales volumes for oil and natural gas and slightly lower realized natural gas sales prices as well as higher expenses for production, depreciation, depletion and administration. The R&M business generated strong profits in 2007, increasing \$95.1 million compared to 2006. The improvement was primarily due to higher U.S. refining margins in 2007 compared to 2006, a fully operational refinery at Meraux, Louisiana, during 2007, and lower hurricane repair expenses in 2007, but R&M earnings in 2007 included an unfavorable impact from noncash inventory revaluations in the U.K. The Meraux refinery was shut-down for repairs for the first five months of 2006 following significant damage caused by Hurricane Katrina in late August 2005. The Company incurred significant repair costs in 2006 at Meraux following Hurricane Katrina, certain of which were not recoverable through insurance policies. In the U.K., the Company acquired the remaining 70% interest in the Milford Haven, Wales, refinery in late 2007. Under the Company's last-in, first-out accounting policy for inventory, an after-tax noncash charge of \$59.5 million was recorded in the year of acquisition to reduce the carrying value of crude oil and refined products inventory to beginning of year prices, which were significantly lower than at the end of the year. The net costs of corporate activities increased by \$13.6 million in 2007 compared to 2006, with the cost increase mostly attributable to higher net interest expense and higher losses on transactions denominated in foreign currencies. The higher net interest expense was caused by higher average borrowing levels, partially offset by a higher level of interest costs capitalized to E&P development projects. The U.S. dollar generally weakened against other significant foreign currencies used in the Company's business in 2007, especially compared to the Canadian dollar. The 2007 period included lower corporate administrative costs mostly due to higher expense in 2006 for an educational assistance contribution commitment.

Sales and other operating revenues were \$4.1 billion higher in 2007 than in 2006 mostly due to higher sales volumes and sales prices for gasoline and other refined products, higher sales prices for crude oil produced by the Company, and higher sales volumes for merchandise at retail gasoline stations. Sales volumes for oil and natural gas were lower in 2007 than in 2006. Gain/(loss) on sales of assets in 2007 was \$9.8

million unfavorable to 2006 as the Company had no major asset sales in 2007. Interest and other income was lower by \$3.0 million in 2007

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due mostly to higher losses on foreign currency exchange attributable to a weakening of the U.S. dollar against the primary foreign currencies affecting the Company's operations, which mainly include the Canadian dollar and the British pound sterling. Crude oil and product purchases expense increased by \$3.7 billion in 2007 compared to 2006 due to a combination of higher purchase prices and throughput volumes of crude oil and other feedstocks at the Company's refineries, higher prices and volumes of refined petroleum products purchased for sale at retail gasoline stations, and higher levels of merchandise purchased for sale at the gasoline stations. The higher crude oil purchase volumes in 2007 were caused by the Meraux refinery being operational throughout 2007 following about five months of downtime for hurricane-related repairs in 2006. Operating expenses increased by \$218.8 million in 2007 compared to 2006 and included higher refinery and retail station costs, higher workover and repair costs for Gulf of Mexico oil and gas fields, and higher costs for oil field operations in Malaysia, the U.K. and Ecuador and for Canadian synthetic oil operations at Syncrude. Exploration expenses were \$16.2 million lower in 2007 than in 2006 primarily associated with less dry hole and geophysical expenses in Malaysia, but partially offset by higher costs in Canada for dry holes, geophysical, lease amortization and settlement of two work commitments on leases formerly held in the Scotian Shelf. Selling and general expenses were \$0.8 million higher in 2007 than in 2006 as higher compensation, insurance and Berkana Energy administrative costs in 2007 were almost offset by lower costs associated with an educational assistance program called the El Dorado Promise. The Company acquired 80% of Berkana Energy in December 2006, and subsequently sold this investment in January 2008. Depreciation, depletion and amortization expense was \$105.8 million higher in 2007 compared to 2006 due mostly to higher barrel-equivalent unit rates for depreciation for virtually all E&P segments and higher depreciation for the Meraux refinery and retail gasoline stations. Impairment of long-lived assets of \$40.7 million in 2007 primarily related to closing 55 underperforming gasoline stations in the U.S. and Canada. Accretion of asset retirement obligations increased by \$5.3 million in 2007 mostly due to additional abandonment obligations incurred as Kikeh development wells were drilled during the year, and higher anticipated future abandonment costs on existing wells in the U.S. Net costs associated with hurricanes was lower in 2007 by \$106.2 million mostly due to uninsured repair costs incurred in 2006 at the Meraux refinery following Hurricane Katrina in 2005. The \$3.0 million of hurricane expense recorded in 2007 related to a downward adjustment of anticipated insurance recoveries at the Meraux refinery based on updated projected loss limits announced by the Company's primary property insurer. Interest expense increased by \$22.9 million in 2007 mostly associated with higher average debt levels during the year compared to 2006. The amount of interest costs capitalized to property, plant and equipment increased by \$6.8 million in 2007 due to higher spending on E&P development projects in Malaysia, the U.S. and the Republic of the Congo. Minority interest in operations of Berkana Energy in Canada was favorable \$0.6 million in 2007 compared to 2006. Income tax expense was \$77.0 million higher in 2007 than in 2006 and was mainly attributable to higher pretax income levels. The effective income tax rate for consolidated earnings rose from 37.9% in 2006 to 38.0% in 2007. The tax rate in both years was 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 exceed 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 the ability to obtain tax benefits for these costs in future years is uncertain. The tax rates in both years benefitted, however, from overall favorable effects of tax rate changes in foreign countries.

**Segment Results** In the following table, the Company's results of operations for the three years ended December 31, 2008 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.

| <i>(Millions of dollars)</i> | <b>2008</b>     | <b>2007</b> | <b>2006</b> |
|------------------------------|-----------------|-------------|-------------|
| Exploration and production   |                 |             |             |
| United States                | <b>\$ 156.6</b> | 98.2        | 212.4       |
| Canada                       | <b>588.7</b>    | 370.2       | 330.6       |
| United Kingdom               | <b>73.8</b>     | 47.6        | 60.7        |
| Malaysia                     | <b>865.3</b>    | 148.2       | (5.9)       |
| Ecuador                      | <b>(2.9)</b>    | 28.5        | 38.4        |
| Other                        | <b>(81.6)</b>   | (35.6)      | (19.4)      |
|                              | <b>1,599.9</b>  | 657.1       | 616.8       |
| Refining and marketing       |                 |             |             |
| North America                | <b>227.9</b>    | 230.4       | 77.5        |
| United Kingdom               | <b>85.9</b>     | (24.7)      | 33.1        |
|                              | <b>313.8</b>    | 205.7       | 110.6       |
| Corporate and other          | <b>(173.7)</b>  | (96.3)      | (82.7)      |

Net income

\$ 1,740.0 766.5 644.7

**Exploration and Production** Earnings from exploration and production operations were \$1.60 billion in 2008, \$657.1 million in 2007 and \$616.8 million in 2006. E&P earnings improved \$942.8 million in 2008 compared to 2007 with the significant increase primarily due to higher average realized sales prices for the Company's oil and natural gas production, higher crude oil production volumes and gains on disposals of Canadian assets. Results in 2007 were favorably impacted by income tax benefits associated with tax rate reductions in Canada. The 2008 results were unfavorably affected compared to 2007 by lower natural gas sales volumes and higher expenses for exploration, production, depreciation, depletion, administration and accretion of discounted abandonment liabilities. Crude oil sales volumes in 2008 were 41% higher than in 2007, compared with a 29% increase in crude oil production in 2008 compared to 2007. Crude oil sales volumes grew more than



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production in 2008 due to the timing of sale transactions as the Company had a lower inventory of unsold crude oil at year-end 2008 compared to a year earlier. The significant unsold crude oil inventory at year-end 2007 was mostly at Kikeh where sales volumes lagged production in late 2007 during the start-up phase of this field. During 2008, higher oil sales volumes in Malaysia attributable to higher production volumes at the Kikeh field were partially offset by lower oil sales volumes at most other producing areas. Lower U.S. crude oil sales volumes in 2008 were primarily due to reduced production volumes at several Gulf of Mexico fields following Hurricanes Gustav and Ike. Certain facilities owned by other companies downstream of our producing fields were down for repairs for an extended period of time in the fourth quarter 2008. Lower oil sales volumes in Canada were attributable to field decline at Hibernia, field decline and a higher royalty rate at Terra Nova, sale of the Lloydminster heavy oil property in Western Canada and more downtime at Syncrude. Lower crude oil sales volumes in the U.K., Ecuador and West Patricia, offshore Sarawak Malaysia, were mostly caused by production declines as these fields mature. Natural gas sales volumes were 9% lower in 2008 than 2007 and the reduction was mostly due to sale of Berkana Energy in January 2008. Additionally, several of the Company's Gulf of Mexico fields were either shut in or had curtailed gas production while downstream facilities owned by others were repaired following third quarter hurricanes. The Company's average realized oil sales price was 38% higher in 2008 than 2007, and the average North American natural gas sales price was 33% higher in 2008.

E&P earnings improved \$40.3 million in 2007 compared to 2006 primarily due to higher average realized oil sales prices in the latter year for the Company's production. In addition, exploration expenses were lower by \$16.1 million in 2007. Both years were favorably affected by income tax benefits associated with tax rate reductions in foreign countries. The 2007 results were unfavorably impacted compared to 2006 by lower oil and natural gas sales volumes, lower realized natural gas sales prices in North America and higher expenses for production, depreciation, depletion, administration and accretion of discounted abandonment liabilities. Crude oil sales volumes in 2007 were 3% lower than in 2006, despite a 4% increase in crude oil production in 2007 compared to 2006. The lower sales volumes were caused by the timing of sale transactions as the Company had a larger inventory of unsold crude oil at year-end 2007 compared to a year earlier. The 2007 increase in unsold crude oil inventory, which was primarily at the Kikeh field in Malaysia, returned to normal levels during 2008. During 2007, lower oil sales volumes in the U.S. and Ecuador were only partially offset by higher oil sales volumes in Malaysia and Canada. The lower sales volumes in the U.S. were due to field declines in the Gulf of Mexico, while lower sales volumes in Ecuador were caused by nonrecurring make-up sales volumes in 2006 that related to a prior year. Higher oil sales volumes in Malaysia were mostly caused by start-up of the significant Kikeh field, offshore Sabah, in August 2007, partially offset by lower production at the West Patricia field, offshore Sarawak. Higher volumes in Canada were attributable to better production volumes at the Terra Nova field in the Jeanne d'Arc basin, offshore Newfoundland, which was shut-in for repairs for about six months in 2006. Natural gas sales volumes were 19% lower in 2007 than 2006 and the reduction was mostly due to field declines for maturing fields in the Gulf of Mexico and onshore south Louisiana as well as lower natural gas production at U.K. North Sea fields. The Company's average realized oil sales price was 20% higher in 2007 than 2006, while North American natural gas sales prices averaged 5% less in 2007 than in 2006.

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-37 and F-38 of this Form 10-K report. Average daily production and sales rates and weighted average sales prices are shown on page 6 of the 2008 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.

| <i>(Millions of dollars)</i>     | 2008     | 2007  | 2006  |
|----------------------------------|----------|-------|-------|
| United States                    |          |       |       |
| Oil and gas liquids              | \$ 374.0 | 310.8 | 440.1 |
| Natural gas                      | 162.1    | 121.7 | 160.4 |
| Canada                           |          |       |       |
| Conventional oil and gas liquids | 775.8    | 628.6 | 476.0 |
| Natural gas                      | 5.5      | 23.0  | 24.1  |
| Synthetic oil                    | 459.6    | 351.4 | 270.0 |
| United Kingdom                   |          |       |       |
| Oil and gas liquids              | 189.4    | 129.5 | 156.8 |
| Natural gas                      | 25.8     | 16.6  | 23.3  |
| Malaysia                         |          |       |       |
| Oil and gas liquids              | 1,985.6  | 436.0 | 219.6 |
| Natural gas                      | 0.1      |       |       |
| Ecuador crude oil                | 80.2     | 126.1 | 122.7 |

|                            |                   |         |         |
|----------------------------|-------------------|---------|---------|
| Total oil and gas revenues | <b>\$ 4,058.1</b> | 2,143.7 | 1,893.0 |
|----------------------------|-------------------|---------|---------|

The Company's crude oil, condensate and natural gas liquids production averaged 118,254 barrels per day in 2008, 91,522 barrels per day in 2007 and 87,817 barrels per day in 2006. Production of crude oil, condensate and natural gas liquids in 2008 increased by 26,732 barrels per day, or 29% compared to 2007, primarily due to continued ramp-up of the Kikeh field in Block K, offshore Sabah, Malaysia. This prolific field, which came on production in August 2007 produced 53,000 net barrels of oil per day for the full-year 2008 compared to 11,658 barrels per day

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in 2007. Light oil production in Canada declined from 596 barrels per day in 2007 to 46 barrels per day in 2008 due to sale of Berkana Energy in January 2008. Heavy oil production in the Western Canadian Sedimentary Basin (WCSB) fell from 11,524 barrels per day in 2007 to 8,484 barrels per day in 2008, due to sale of the Lloydminster property in 2008 and lower production volumes at the Seal field in Alberta. Oil production at Hibernia, offshore Newfoundland, was 8,542 barrels per day in 2008, up slightly from 8,314 barrels per day in 2007. Oil production decreased at Terra Nova, offshore Newfoundland, from 10,557 barrels per day in 2007 to 8,284 barrels per day in 2008. The 2008 reduction at Terra Nova was attributable to natural field decline plus a higher royalty rate. Syncrude production totaled 12,546 barrels per day in 2008 compared to 12,948 barrels per day in 2007, with the decline caused by more downtime for repairs and maintenance in the current year. Oil production declined in the U.S. from 12,989 barrels per day in 2007 to 10,668 barrels per day in 2008. The reduction was primarily at Gulf of Mexico fields where production was curtailed while awaiting repairs to downstream facilities owned by other companies that were damaged by third quarter hurricanes. Oil production in the U.K. was down from 5,281 barrels per day in 2007 to 4,869 barrels per day in 2008, with the reduction caused by declining production at the Company's primary fields in the North Sea. The West Patricia field, offshore Sarawak Malaysia, had net production of 4,403 barrels per day in 2008 after production levels of 8,709 barrels per day in 2007. West Patricia experienced declining production and a smaller portion of production was allocated to the Company's account under the production sharing contract. Oil production totaled 7,412 barrels per day in Ecuador in 2008, compared to 8,946 barrels per day in 2007 due to a shut-down of the Block 16 development drilling program during 2008 following an arbitrary decision by the government to impose a 99% revenue sharing provision starting in late 2007 on all sales prices exceeding a benchmark price that averaged about \$23.50 per barrel during the year.

Production of crude oil, condensate and natural gas liquids in 2007 increased by 3,705 barrels per day, or 4% compared to 2006, primarily due to start-up in August of the Kikeh field in Block K, offshore Sabah, Malaysia. This prolific field came on production only five years after discovery. Kikeh produced 11,658 barrels of oil per day for the full-year 2007. Oil production also increased in 2007 at Terra Nova, offshore eastern Canada, at Syncrude in Alberta, and in Ecuador. Oil volumes declined in 2007 at most other areas, including the U.S. and at Hibernia, West Patricia, the U.K. North Sea and the WCSB. Terra Nova produced throughout 2007 after being off-line for major equipment repairs for six months in 2006. Total production at Terra Nova was 10,557 barrels per day in 2007 and 3,900 barrels per day in 2006. Syncrude production totaled 12,948 barrels per day in 2007 compared to 11,701 barrels per day in 2006. The 2007 production increase at Syncrude was mostly attributable to a third coker unit that started up during 2006. Oil production totaled 8,946 barrels per day in Ecuador, up 338 barrels per day due to a more significant development drilling campaign in Block 16 in 2007. Oil production declined in the U.S. from 21,112 barrels per day in 2006 to 12,989 barrels per day in 2007. The reduction was due to declines at various maturing fields in the Gulf of Mexico. Heavy oil production in the WCSB fell from 12,613 barrels per day in 2006 to 11,524 barrels per day in 2007, primarily due to a slower development drilling program for non-operated fields in Alberta. Oil production at Hibernia, offshore Newfoundland, was 8,314 barrels per day in 2007 down from 10,996 barrels per day in 2006 as the field experienced production decline during the year. Oil production in the U.K. was down from 7,146 barrels per day in 2006 to 5,281 barrels per day in 2007, with the reduction caused by declining production at the Company's primary fields in the North Sea. The West Patricia field, offshore Sarawak Malaysia, had net production of 8,709 barrels per day in 2007 after production levels of 11,298 barrels per day in 2006. West Patricia experienced declining production along with an increased government take under the production sharing contract.

Worldwide sales of natural gas were 55.5 million cubic feet (MMCF) per day in 2008, 61.1 million in 2007 and 75.3 million in 2006. Natural gas sales volumes in the United States increased 1% in 2008 and averaged 45.8 MMCF per day. The increase of 0.7 MMCF per day in 2008 would have been significantly higher but for the reduced gas production associated with hurricane damage to downstream facilities late in the year. Natural gas sales volumes in Canada averaged 1.9 MMCF per day in 2008, 81% lower than 2007. In January 2008, the Company sold Berkana Energy, formerly its largest gas producing asset in Canada. Natural gas sales volumes in the U.K. were up 7% in 2008 and averaged 6.4 MMCF per day. The U.K. gas sales volumes were mostly attributable to more gas volumes sold at the Mungo and Monan fields in the North Sea. Natural gas production commenced from the Kikeh field offshore Sabah Malaysia in December 2008 and sales volumes averaged 1.4 MMCF per day for the year.

Natural gas sales volumes in the United States fell 21% in 2007 and averaged 45.1 MMCF per day. The decline of 11.7 MMCF per day in 2007 was due to declines at various fields in the deepwater Gulf of Mexico and onshore South Louisiana. Natural gas sales volumes in 2007 increased 2% in Canada and averaged 9.9 MMCF per day. Natural gas sales volumes in the U.K. fell 31% in 2007 and averaged 6.0 MMCF per day. The lower U.K. gas sales volumes were attributable to lower associated gas volumes sold from two oil fields in the North Sea.

The Company's average worldwide realized crude oil, condensate and gas liquids sales price was \$85.31 per barrel in 2008 compared to \$62.05 per barrel in 2007. This was an increase of 37% in 2008. Oil prices began to plummet in the second half of 2008 and continued to display weakness in early 2009 as West Texas Intermediate crude oil prices averaged about \$42 per barrel in January 2009. In the U.S., the Company realized an average price of \$95.74 per barrel in 2008, up 46% from 2007. The average sales price in 2008 for heavy oil produced in Canada was \$59.05 per barrel, 80% higher than in 2007. Hibernia and Terra Nova sales prices averaged \$97.09 and \$96.23 per barrel, respectively, during 2008, which were increases of 36% and 40%. Synthetic oil production sold for \$100.10 per barrel, up 35% from a year earlier. U.K. oil prices increased 32% to \$90.16 per barrel in 2008. In Malaysia, oil produced at the Kikeh field sold for 2% less in 2008 than in 2007, with an average of \$89.36 per barrel for the just completed year. Kikeh came on stream in August 2007 and all sales during that year occurred in the fourth quarter when prices were at the strongest point during 2007. At the West Patricia field offshore Sarawak the 2008 average sales price of \$72.04

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per barrel was 22% above the 2007 average price. The average realized sales price after revenue sharing with the Ecuadorian government for Block 16 oil was \$27.83 per barrel, a decrease of 24% from 2007. During 2008, the government required a 99% share of Block 16 realized sales

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prices that exceeded a benchmark price that escalates with the monthly U.S. Consumer Price Index. This government revenue sharing increased from 50% above the benchmark price to 99% in October 2007. At year-end 2008, the benchmark oil price for Block 16 was approximately \$23.36 per barrel. The Company and its partners in Block 16 have initiated arbitration proceedings claiming that the government does not have the right under the contract to change this sharing arrangement. The Company is unable to predict when the arbitration proceedings will be concluded. The Company and its partners stopped paying the 99% revenue share above the benchmark price to the government in mid-2008. The Company has recorded a liability of approximately \$83 million for unpaid revenue share with the government at year-end 2008.

The Company's average realized oil sales price was \$62.05 per barrel in 2007, up 20% from the 2006 average of \$51.62 per barrel. In the U.S., the Company realized an average price of \$65.57 per barrel in 2007, up 14% from 2006. The 2007 average sales price for Canadian heavy oil production was \$32.84 per barrel, 27% higher than in 2006. Hibernia and Terra Nova sales prices averaged \$71.43 and \$68.54 per barrel, respectively, during 2007, which were increases of 13% and 15%. Synthetic oil production sold for \$74.35 per barrel in 2007, up 18% from a year earlier. U.K. oil prices increased 6% to \$68.38 per barrel in 2007. In Malaysia, oil produced at the West Patricia field sold for 14% more in 2007 than in 2006, with an average of \$59.05 for the year. The Kikeh field came on stream in August 2007 and all sales from this field occurred in the stronger price environment during the fourth quarter 2007 at an average of \$90.84 per barrel. The average realized sales price after revenue sharing with the Ecuadorian government for Block 16 oil was \$36.47 per barrel, an increase of 8% from 2006. For most of the year, the government received a 50% share of realized sales prices that exceeded a benchmark price that escalates with the monthly U.S. Consumer Price Index. However, in mid-October the government changed its share of such revenue from 50% to 99%. At year-end 2007, the benchmark oil price for Block 16 was approximately \$23.28 per barrel.

The Company's natural gas sales prices rose in 2008 compared to 2007. The Company's average realized North American natural gas sales prices increased by 33% in 2008 to \$9.54 per thousand cubic feet (MCF). In the U.K., the average 2008 natural gas price rose 46% to \$10.98 per MCF.

The Company's average realized North American natural gas sales prices fell 5% in 2007 to \$7.19 per MCF. In the U.K., the average 2007 natural gas price rose 3% to \$7.54 per MCF.

Based on 2008 sales volumes and deducting taxes at marginal rates, each \$1.00 per barrel and \$0.10 per MCF fluctuation in prices would have affected 2008 earnings from exploration and production operations by \$28.4 million and \$1.3 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.

Production expenses were \$642.6 million in 2008, \$463.0 million in 2007 and \$383.2 million in 2006. These amounts are shown by major operating area on pages F-37 and F-38 of this Form 10-K report. Costs per equivalent barrel during the last three years are shown in the following table.

| <i>(Dollars per equivalent barrel)</i> | 2008     | 2007  | 2006  |
|--|----------|-------|-------|
| United States                          | \$ 10.01 | 10.75 | 7.10  |
| Canada                                 |          |       |       |
| Excluding synthetic oil                | 9.44     | 8.77  | 9.36  |
| Synthetic oil                          | 41.08    | 30.56 | 28.23 |
| United Kingdom                         | 13.21    | 10.34 | 6.19  |
| Malaysia                               | 10.31    | 12.60 | 7.46  |
| Ecuador                                | 11.05    | 10.60 | 7.85  |
| Worldwide excluding synthetic oil      | 10.29    | 10.29 | 7.91  |

Production cost per equivalent barrel decreased in the U.S. in 2008 compared to 2007 due to lower costs incurred for workovers and repairs at fields in the Gulf of Mexico. U.S. per-barrel equivalent costs were higher in 2007 versus 2006 mostly due to higher workover and field repairs and lower production volumes. The per-unit costs for Canadian conventional oil and gas operations, excluding Syncrude, were higher in 2008 than 2007 mostly due to lower production levels. The cost for conventional oil in Canada was lower in 2007 than 2006 primarily due to higher production levels and lower repair costs at Terra Nova in 2007. Terra Nova was shut-in for major repairs for six months in 2006. Higher production costs per barrel for Canadian synthetic oil operations in 2008 were due to additional costs for fuel and repairs and lower production levels. The increased Syncrude cost in 2007 was primarily due to a higher net profit royalty rate and a higher foreign exchange rate. The average cost per barrel in the U.K. in 2008 versus 2007 was caused by lower overall production levels and higher repair costs. The higher average U.K. cost per barrel in 2007 was mostly due to higher maintenance costs, lower oil production at the North Sea fields and a higher foreign exchange rate. The lower average cost per barrel in Malaysia in 2008 compared to 2007 was attributable to higher production at Kikeh where unit costs per equivalent barrel are lower than at West Patricia. The higher per-unit cost in Malaysia in 2007 was due to the start-up phase for Kikeh oil and a lower production level for West Patricia compared to 2006. Higher per-unit operating costs in Ecuador in 2008 compared to 2007 were mostly

attributable to lower production levels in the most recent year. Higher per-unit operating costs in Ecuador in 2007 were primarily caused by additional water handling costs as Block 16 wells mature.

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Exploration expenses 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-37 and F-38 on this Form 10-K report. Certain of the expenses are included in the capital expenditures total for exploration and production activities.

| <i>(Millions of dollars)</i>   | 2008            | 2007  | 2006  |
|--------------------------------|-----------------|-------|-------|
| Dry holes                      | <b>\$ 129.5</b> | 67.1  | 111.0 |
| Geological and geophysical     | <b>85.2</b>     | 67.7  | 73.1  |
| Other                          | <b>17.7</b>     | 35.1  | 12.6  |
|                                | <b>232.4</b>    | 169.9 | 196.7 |
| Undeveloped lease amortization | <b>112.0</b>    | 33.2  | 22.5  |
| Total exploration expenses     | <b>\$ 344.4</b> | 203.1 | 219.2 |

Dry hole expense was \$62.4 million more in 2008 than in 2007 and was attributable to more exploration drilling capital expenditures in 2008. With mostly new E&P management in 2007, much of that year was spent reevaluating the Company's worldwide exploration drilling prospects. The higher costs for dry holes in 2008 was mostly in the offshore waters of Malaysia and Western Australia. Dry holes expense was \$43.9 million less in 2007 than 2006 primarily due to a lower level of exploration drilling activity in 2007. Geological and geophysical (G&G) expenses were \$17.5 million higher in 2008 mostly due to a 3D seismic program at Block 37, offshore Suriname, and more seismic activities in the Tupper area in British Columbia. G&G expenses were \$5.4 million less in 2007 than 2006 primarily due to lower spending in Malaysia for 3D seismic for Blocks SK 311 and H and lower geophysical analyses on PM Blocks 311/312. The lower Malaysian costs were partially offset by higher seismic costs in 2007 in the Gulf of Mexico and offshore Australia, and higher geophysical studies offshore the Republic of the Congo. Other exploration expenses in 2008 were \$17.4 million lower than 2007 mostly due to a \$21.9 million settlement in 2007 for unfulfilled work commitments on two expiring Scotian Shelf leases, offshore eastern Canada. Other exploration expenses in 2007 were \$22.5 million higher than in 2006 also due to the Scotian Shelf work commitment settlement. Undeveloped leasehold amortization expense rose \$78.8 million in 2008 compared to 2007, after an increase of \$10.7 million in 2007 compared to 2006, primarily due to amortization of undeveloped land acquisition costs at the Tupper property in northeast British Columbia, where the Company has aggressively added undeveloped acreage over the last two years.

A \$2.6 million charge in the exploration and production business for asset impairment in 2007 related to write-down of an unused E&P administrative office to estimated fair value.

Expense of \$1.9 million was incurred in 2006 in the Company's exploration and production operations for uninsured costs to repair damages and to recognize associated higher insurance costs caused by Hurricanes Katrina and Rita in the Gulf of Mexico.

Depreciation, depletion and amortization expense related to exploration and production operations totaled \$573.5 million in 2008, \$376.8 million in 2007 and \$297.0 million in 2006. The increase of \$196.7 million in 2008 expense compared to 2007 was mostly caused by a much higher production level at the Kikeh field, offshore Sabah, Malaysia. The \$79.8 million increase in 2007 compared to 2006 was caused by generally higher per-unit rates for development capital, the start-up of the Kikeh field, and an increase in foreign exchange rates in Canada and the U.K. The Company continues to experience high drilling and related costs caused by a strong demand for such services.

The exploration and production business recorded expenses of \$23.5 million in 2008, \$16.1 million in 2007 and \$10.8 million in 2006 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 increase in accretion costs in 2008 was associated with higher estimated abandonment costs at Syncrude and additional development wells drilled at the Kikeh field. The higher accretion costs in 2007 were mostly related to higher estimated future abandonment costs for facilities and wells in the Gulf of Mexico and future abandonment obligations related to Kikeh development wells drilled in 2007.

The effective income tax rate for exploration and production operations was 37.5% in 2008, 34.6% in 2007 and 36.1% in 2006. The effective tax rate was higher in 2008 than the previous two years as both 2007 and 2006 included net tax benefits from enacted changes in foreign tax rates. Canada lowered federal tax rates in both 2007 and 2006, and in 2006 the Canadian provinces of Alberta and Saskatchewan also reduced tax rates. The net benefit from these Canadian tax rate reductions, which effectively reduced recorded deferred tax liabilities was \$38.7 million in 2007 and \$37.5 million in 2006. The 2008 effective tax rate exceeded the U.S. statutory tax rate due to higher overall foreign tax rates and exploration activities in areas where current tax relief is not available. The effective tax rate in 2007 was slightly below the U.S. statutory tax

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rate of 35% primarily due to the enacted Canadian Federal tax rate reduction during the year. The 2007 effective tax rate was lower than in 2006 mostly due to a deferred tax expense in 2006 related to a 10% increase in U.K. tax rates on oil and gas profits. A \$4.4 million U.S. tax benefit was realized in 2007 for a charitable building donation. Also in 2007, the Company incurred lower exploration and other expenses in tax jurisdictions where tax relief is currently not available. Tax jurisdictions with no current tax benefit on expenses primarily include non-revenue generating areas in Malaysia, the Republic of the Congo, Suriname, Australia and Indonesia. 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 Blocks H, P, L and M, offshore Sabah, and Blocks PM 311/312, offshore Peninsula Malaysia. The 2006 effective tax rate was only slightly higher than the U.S. statutory tax rate of 35% due to net overall benefits from the aforementioned tax rate changes in Canada and the U.K. in that year.



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At December 31, 2008, approximately 38% of the Company's U.S. proved oil reserves and 40% of the U.S. proved natural gas reserves are undeveloped. Virtually all of the total U.S. undeveloped reserves (on a barrel of oil equivalent basis) are associated with the Company's various deepwater Gulf of Mexico fields. Further drilling, facility construction and well workovers are required to move undeveloped reserves to developed. In Block K Malaysia, 23% of oil reserves of 76.6 million barrels and 25% of natural gas reserves of 106.5 billion cubic feet at year-end 2008 for the Kikeh field are undeveloped pending completion of facilities and continued development drilling, and 100% of the 15.1 million barrels of oil reserves at the Kakap field are undeveloped pending completion of drilling operations directed by another company. Also in Malaysia, there were 298.7 billion cubic feet of undeveloped natural gas reserves at various fields offshore Sarawak at year-end 2008, which were held under this category pending completion of development drilling and facilities. First gas production at the Kikeh field occurred in December 2008 and is scheduled for the Sarawak gas fields in the third quarter 2009. On a worldwide basis, the Company spent approximately \$783 million in 2008, \$769 million in 2007 and \$560 million in 2006 to develop proved reserves. The Company expects to spend about \$859 million in 2009, \$377 million in 2010 and \$250 million in 2011 to move currently undeveloped proved reserves to the developed category.

**Refining and Marketing** The Company's refining and marketing (R&M) operations generated record earnings of \$313.8 million in 2008, after earning \$205.7 million in 2007 and \$110.6 million in 2006. The 53% improvement in 2008 earnings compared to 2007 was caused by favorable U.K. refining profits following the acquisition of the remaining 70% of the Milford Haven refinery in December 2007, and nonrecurring charges in 2007 for a last-in, first-out (LIFO) inventory writedown in the U.K. and retail gasoline station impairments in North America.

The 86% improvement in R&M earnings in 2007 compared to 2006 was due to stronger refining margins in the U.S., lower hurricane-related expenses in 2007, and a fully operational Meraux refinery which was shut-down for repairs for about five months in 2006 following Hurricane Katrina. Total hurricane expenses after taxes in R&M operations were \$1.9 million in 2007 and \$67.1 million in 2006. The Meraux, Louisiana refinery significantly increased crude oil throughputs in 2007 compared to 2006 as the earlier year was unfavorably affected by downtime for repairs. R&M earnings in 2007 were net of two significant charges—a \$24.5 million after-tax charge related to closure of 55 gasoline stations in the U.S. and Canada, and an after-tax inventory charge of \$59.5 million in the U.K.

The Company's North American R&M operations generated earnings of \$227.9 million in 2008, \$230.4 million in 2007 and \$77.5 million in 2006. North American operations include refining activities in the United States and marketing activities in the United States and Canada. North American R&M earnings were down slightly in 2008 compared to 2007 as lower profits generated by the U.S. refining operations were not quite offset by much stronger retail marketing profits in 2008. Demand for gasoline declined in the U.S. in 2008 due to higher costs and a weakening economy. This lower demand led to much tighter crack spreads for U.S. refineries in 2008 compared to 2007. Crack spreads represent the uplift of gasoline and distillate prices over the cost of crude oil feedstocks. Both U.S. refineries were temporarily shut-down for turnaround activities during 2008. The 2007 and 2006 operating results for the Company's North American refining business were negatively impacted by hurricane-related costs and below optimal Meraux refinery crude throughput volumes as a result of Hurricane Katrina. Uninsured damages, higher insurance premiums, settlement of the class action oil spill litigation and other hurricane-related pretax costs in the Company's North American operations were \$3.0 million in 2007 and \$107.3 million in 2006. The hurricane expense in 2007 was caused by a downward adjustment of expected insurance recoveries based on an updated loss limit published by the Company's primary insurer. The Meraux refinery throughput volumes of crude oil and other feedstocks averaged 103,169 barrels per day in 2008, 112,840 barrels per day in 2007 and 57,198 barrels per day in 2006. Significant flooding and wind damage associated with Hurricane Katrina resulted in the refinery being shut down from late August 2005 through May 2006. During the refinery's nine months of downtime for repairs, major upgrades and improvements were completed, and turnarounds on the refinery's hydrocracker and fluid catalytic cracking unit debutanizer were performed. The Company's refinery in Superior, Wisconsin also generated weaker earnings in 2008 than in 2007 as a result of tighter crack spreads in the later year. North American retail gasoline station operations had improved results in 2008 compared to 2007 as this business enjoyed higher per gallon margins, higher sales volumes and lower store closure costs compared to the prior year. This operation's business model of always offering competitive fuel prices usually leads to increased sales volumes during periods of high gasoline prices such as in the first nine months of 2008. The operating results for the Company's North American retail gasoline stations were lower in 2007 compared to 2006 as 55 underperforming stores were closed during 2007, including 47 in the U.S. and all eight stations in Canada. The Company recorded impairment expense of \$38.2 million in 2007 associated with these store closures. Excluding this impairment charge, the 2007 operating results for this business would have been essentially flat with 2006. A total of 52 retail stations were added in the U.S. during 2008, including 21 in the parking lots of Walmart Supercenters and 31 at other stand-alone locations. Average fuel sales volumes per station increased again in 2008, the 11th straight year of improvements.

Unit margins (sales realization less costs of crude and other feedstocks, transportation to point of sale and refinery operating and depreciation expenses) averaged \$4.30 per barrel in North America in 2008, \$4.28 in 2007 and \$3.48 in 2006. North American refined product sales volumes increased 3% to a record 427,490 barrels per day in 2008, following a 19% increase to 416,668 barrels per day in 2007. The Company's U.S. retail gasoline stations continued to increase per site fuel sales volumes with a 10% increase in the average monthly fuel sales volume per station in 2008 following a 4% increase in 2007.

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Operations in the United Kingdom had earnings of \$85.9 million in 2008 compared to a loss of \$24.7 million in 2007 and earnings of \$33.1 million in 2006. On December 1, 2007, the Company acquired 100% of the Milford Haven, Wales refinery, after having a 30% interest in the asset prior to that date. The improved earnings in 2008 compared to 2007 were mostly related to profits generated by the Milford Haven refinery as the refinery generated stronger margins in 2008 and the 2007 period included a significant inventory charge. In association with the late 2007 Milford Haven acquisition, the Company built a significant additional layer of crude oil and refined products inventory. The 2007 period included

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a \$59.5 million after-tax non-cash charge to reduce the carrying value of these higher inventory levels to early 2007 prices. Under the Company's LIFO inventory accounting policy, inventory volume increases are priced at the first purchase prices during the year, and the prices of crude oil and refined products were at a much lower level in early 2007 compared to the price at the time these products were acquired near year-end 2007. The LIFO inventory charge reduced the average carrying value for these additional inventories in the U.K. by approximately \$40 per barrel. Excluding this non-cash inventory charge, the 2007 operating result for the Company's U.K. operations was slightly improved over 2006. In late 2008, the Company purchased six existing fuel stations and leased an additional 63 stations in England and Scotland.

Unit margins in the United Kingdom averaged \$4.30 per barrel in 2008, \$0.22 per barrel in 2007 and \$6.39 per barrel in 2006. Overall sales of refined products in the U.K. increased more than 200% in 2008, following an increase of 19% in 2007. The 2008 sales increase was attributable to additional quantities of refined products produced and sold throughout 2008 at the Milford Haven refinery following the Company's acquisition of the remaining 70% interest in December 2007.

**Corporate** The after-tax costs of corporate activities, which include interest income, interest expense, foreign exchange gains and losses, and corporate overhead not allocated to operating functions, were \$173.7 million in 2008, \$96.3 million in 2007 and \$82.7 million in 2006. The net cost of corporate activities increased \$77.4 million in 2008 compared to 2007 primarily due to higher costs associated with foreign exchange where transactions are denominated in currencies other than the operation's functional currency. Additionally interest costs, net of amounts capitalized to development projects, and administrative costs were also higher in 2008 than in 2007. The after-tax costs of foreign currency exchange amounted to \$87.8 million in 2008 compared to costs of \$13.8 million in 2007. The additional costs were primarily related to U.S. dollar transactions within the U.K.'s sterling functional downstream operations, as these dollar transactions expanded significantly with the 70% addition of Milford Haven, Wales refinery ownership beginning in December 2007. At year-end 2008 the U.S. dollar had strengthened 28% against the British pound sterling, 5% against the Euro, and 18% against the Canadian dollar compared to the end of 2007. Net interest expense increased \$18.1 million in 2008 compared to 2007 mostly due to lower amounts of interest capitalized to ongoing oil and gas development projects during the just completed year. Administrative expenses in the corporate area increased in 2008 primarily due to higher total compensation expense and higher contributions to community and educational programs in the current year. Interest income increased \$6.6 million in 2008 versus 2007 and was mostly associated with higher average short-term invested funds in Canada and the U.K. Income taxes in 2008 were \$52.7 million favorable to 2007, and were primarily related to benefits on the higher foreign exchange losses and higher net interest expense as discussed above.

Net corporate costs increased \$13.6 million in 2007 compared to 2006 due primarily to higher net interest expense and higher losses on foreign exchange. These higher costs were partially offset by lower costs in 2007 associated with an educational assistance commitment. Net interest expense rose by \$16.1 million in 2007 compared to 2006 due to interest associated with higher average outstanding long-term debt balances. The Company's borrowings increased due to higher capital spending on oil and natural gas development projects in Malaysia, the Republic of the Congo and Canada, and in the downstream business related to capital spending for the purchase of the Milford Haven, Wales refinery and land underlying most gasoline stations at Walmart sites. The amount of interest capitalized to development projects increased in 2007 in association with higher capital development spending. The after-tax effect of foreign exchange was a charge of \$13.8 million in 2007 compared to a charge of \$7.9 million in 2006. The U.S. dollar weakened in 2007 by 17% against the Canadian dollar, 11% against the Euro and 2% against the British pound sterling. Administrative expenses in 2007 in the corporate area were \$20.3 million less than 2006 due mostly to lower costs associated with the El Dorado Promise educational assistance contribution, but partially offset by higher compensation costs in the current year. The El Dorado Promise involves the Company's commitment to contribute \$5.0 million per year through 2016 to pay for post-secondary tuition for eligible graduates of El Dorado High School in Arkansas. Income taxes were unfavorable in the corporate area in 2007 compared to 2006 due to a higher portion of interest and administrative expenses allocable to foreign operations without current tax relief.

## **Capital Expenditures**

As shown in the selected financial data on page 13 of this Form 10-K report, capital expenditures, including exploration expenditures, were \$2,364.7 million in 2008 compared to \$2,357.3 million in 2007 and \$1,262.5 million in 2006. These amounts included \$232.4 million, \$169.9 million and \$196.7 million, respectively, in 2008, 2007 and 2006 for exploration costs that were expensed. Capital expenditures for exploration and production activities totaled \$1,935.3 million in 2008, \$1,780.7 million in 2007 and \$1,082.8 million in 2006, representing 82%, 76% and 86%, respectively, of the Company's total capital expenditures for these years. E&P capital expenditures in 2008 included \$156.0 million for acquisition of undeveloped leases, which included leases acquired in the eastern and central Gulf of Mexico and at the Tupper area of northeastern British Columbia, \$323.6 million for exploration activities, and \$1,455.7 million for development projects. Development expenditures included \$358.3 million for the Tupper natural gas area in British Columbia, \$160.2 million for deepwater fields in the Gulf of Mexico; \$325.7 million for the Kikeh field in Malaysia; \$287.8 million for natural gas and other development activities in SK Blocks 309/311; \$46.5 million for development of the Kakap field in Block K, offshore Malaysia; \$35.6 million for synthetic oil operations at the Syncrude project in Canada; \$37.6 million for western Canada heavy oil projects; \$149.2 million for development of the Azurite field in the Republic of the Congo; \$18.0 million for the Terra Nova and Hibernia oil fields, offshore Newfoundland; and \$22.1 million for fields in the U.K. North Sea. Exploration and production capital expenditures are shown by major operating area on page F-36 of this Form 10-K report.

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Refining and marketing capital expenditures totaled \$426.2 million in 2008, \$572.5 million in 2007 and \$173.4 million in 2006. These amounts represented 18%, 24% and 14% of capital expenditures of the Company in 2008, 2007 and 2006, respectively. Refining capital spending was \$141.8 million in 2008 compared to \$330.0 million in 2007 and \$57.3 million in 2006. Refining capital in 2008 included project costs for additional

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sulfur recovery capacity and property acquisition and improvements at the Meraux, Louisiana refinery, and a cogeneration energy plant at the Milford Haven, Wales refinery. The 2007 refining capital included \$240.7 million for acquisition of the remaining 70% of the Milford Haven, Wales refinery. Most of the remaining refinery capital in 2007 was related to property acquired surrounding the Meraux refinery. The bulk of the refining capital in 2006 was spent at the Meraux refinery where numerous capital improvements were completed while the plant was shut-down for repairs following Hurricane Katrina. Marketing expenditures amounted to \$284.4 million in 2008, \$242.5 million in 2007 and \$116.1 million in 2006. Marketing capital spending in 2008 was split between station construction costs and land acquisitions costs for existing and future retail gasoline stations. The capital spending in 2007 was mostly attributable to acquisition of land underlying retail gasoline stations located at Walmart Supercenters. The majority of marketing expenditures in 2006 was related to construction of retail gasoline stations at Walmart Supercenters in the U.S. The Company added 52 stations within its U.S. retail gasoline network in 2008, after adding 33 in 2007 and 123 in 2006.

### **Cash Flows**

Cash provided by operating activities was \$3.03 billion in 2008, \$1.74 billion in 2007 and \$975.5 million in 2006. Cash provided by operating activities in 2008 was \$1.29 billion more than in 2007 primarily due to higher net income, higher depreciation and higher exploration drilling expenditures. Cash provided by operating activities in 2007 was approximately \$765 million more than in 2006 mostly due to a combination of higher net income, higher expenses for depreciation, impairment and deferred taxes, and a reduction of noncash operating working capital in 2007 versus an increase in 2006. Cash provided by operating activities in 2006 was unfavorably affected by lower oil and natural gas sales volumes and higher operating costs associated with repairs of oil and gas production facilities. Cash provided by operating activities was reduced by expenditures for abandonment of oil and gas properties totaling \$9.2 million in 2008, \$13.0 million in 2007 and \$3.3 million in 2006.

Cash proceeds from property sales were \$362.0 million in 2008, \$21.6 million in 2007 and \$23.8 million in 2006. The 2008 proceeds related to sales of two of the Company's Canadian assets, including its interest in Berkana Energy and the Lloydminster heavy oil property, and a sale of 35% of its working interest in the MPS block offshore the Republic of the Congo. The sales proceeds in 2007 and 2006 primarily related to sales of various properties, real estate and aircraft. During 2008, the Company used available cash flow to repay \$492.8 million of long-term debt. During 2007 and 2006, the Company borrowed \$686.2 million and \$237.7 million, respectively, under notes payable primarily to fund a portion of the Company's development capital expenditures. Cash proceeds from stock option exercises and employee stock purchase plans, including income tax benefits on stock options classified as financing activities, amounted to \$50.0 million in 2008, \$72.4 million in 2007 and \$36.6 million in 2006. Proceeds from Canadian government securities with maturities greater than 90 days at date of acquisition was \$623.1 million in 2008.

Property additions and dry hole costs used cash of \$2.18 billion in 2008, \$1.95 billion in 2007 and \$1.19 billion in 2006. The higher capital expenditures in 2008 compared to 2007 were primarily associated with a more robust exploration program and higher spending on development projects including Kikeh development drilling, Sarawak natural gas, Kakap, Azurite, Tupper and Thunder Hawk. Higher amounts spent in 2007 compared to 2006 mostly related to ongoing E&P development projects, including Kikeh, Azurite, Sarawak gas and one field in the Gulf of Mexico, acquisition of mineral rights in the Tupper area of western Canada, and purchases of land under Company-owned gasoline stations at Walmart stores and surrounding the Meraux refinery. In December 2007, the Company spent \$348.3 million to acquire the remaining 70% interest in the Milford Haven, Wales refinery and associated inventory. Cash of \$1.04 billion was spent in 2008 to acquire Canadian government securities with maturities greater than 90 days at the time of purchase. Cash of \$57.6 million in 2008, \$14.6 million in 2007 and \$12.8 million in 2006 was used for turnarounds at refineries and Syncrude. Cash used for dividends to stockholders was \$166.5 million in 2008, \$127.4 million in 2007 and \$98.2 million in 2006. The Company raised its annualized dividend rate from \$0.75 per share to \$1.00 per share beginning in the third quarter of 2008. The Company had previously increased the annualized dividend rate from \$0.60 per share to \$0.75 per share beginning in the third quarter of 2007.

### **Financial Condition**

Year-end working capital (total current assets less total current liabilities) totaled \$958.8 million in 2008 and \$777.5 million in 2007. 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 \$202.5 million below fair value at December 31, 2008. Cash and cash equivalents at the end of 2008 totaled \$666.1 million compared to \$673.7 million at year-end 2007.

The long-term portion of debt decreased by \$489.9 million during 2008 and totaled \$1.03 billion at year-end 2008, representing 14.0% of total capital employed. Available free cash flow arising primarily from strong crude oil sales prices was used to repay a portion of long-term debt during 2008. Long-term debt increased by \$675.9 million in 2007 as the Company utilized its borrowing capacity to fund its significant ongoing oil and natural gas development projects, with the largest of these being the Kikeh field in Malaysia. Stockholders' equity was \$6.28 billion at the end of 2008 compared to \$5.07 billion a year ago and \$4.12 billion at the end of 2006. A summary of transactions in stockholders' equity accounts is presented on page F-6 of this Form 10-K report.

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Other significant changes in Murphy's year-end 2008 balance sheet compared to 2007 included a \$420.3 million balance of short-term investments in Canadian government securities with maturities greater than 90 days at the time of purchase. There were no such investments with maturities greater than 90 days at December 31, 2007. These slightly longer-term investments were purchased in 2008 because of a tight

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supply of shorter-term securities available for purchase in Canada. A \$386.6 million decrease in accounts receivable was caused by sales of crude oil and refined petroleum products at lower average prices near the end of 2008 compared to 2007. Inventory values were \$22.5 million lower at year-end 2008 than in 2007 mostly due to less unsold crude oil production held in inventory at year-end 2008 compared to 2007. Prepaid expenses increased \$13.0 million in 2008 primarily due to higher prepaid income taxes in the U.K. Short-term deferred income tax assets decreased \$56.5 million at year-end 2008 due mostly to changes in the components of temporary differences for the Company's Canadian operations. Net property, plant and equipment increased by \$617.9 million in 2008 as a significant level of property additions during the year exceeded the additional depreciation and amortization expensed. Goodwill decreased \$14.1 million in 2008 due to a weaker Canadian dollar exchange rate versus the U.S. dollar and an allocation of a portion of goodwill to costs associated with the sale of properties in Canada. Deferred charges and other assets increased \$49.3 million and included higher amounts of deferred turnaround costs following major maintenance performed during the year at the Company's U.S. refineries. Current maturities of long-term debt declined \$2.6 million during 2008 due to a partial repayment of nonrecourse debt associated with the Hibernia field. Notes payable decreased \$7.6 million in 2008 as this borrowing at year-end 2007 was associated with Berkana Energy Corp., which Murphy sold in January 2008. Accounts payable declined by \$487.8 million at year-end 2008 compared to 2007 mostly due to lower amounts owed for crude oil purchases. Income taxes payable increased \$342.6 million at year-end 2008 primarily due to higher taxes owed in the current year on income in Malaysia. Other taxes payable decreased \$47.8 million mostly due to lower excise and value added taxes owed by the Company's U.K. operations at year-end 2008 compared to 2007. Other accrued liabilities decreased by \$18.0 million in 2008 mostly due to lower employee compensation liabilities in the current year. Deferred income tax liabilities were \$38.8 million lower at year-end 2008 due mostly to lower liabilities for future taxes in the U.K. and Canada. The liability associated with future asset retirement obligations increased by \$99.5 million mostly due to development wells drilled during 2008 offshore Malaysia and higher estimated future costs for abandonment of existing facilities at the Company's synthetic oil operations in Canada. Deferred credits and other liabilities increased \$77.7 million in 2008 compared to 2007 mostly due to higher long-term liabilities associated with employee retirement plans. Minority interest in a consolidated subsidiary at the end of 2007 of \$26.9 million related to the 20% of Berkana Energy Corp. that the Company did not own. The Company sold its investment in Berkana in January 2008. The Company had acquired 80% of Berkana in December 2006 in exchange for a non-cash contribution of the Company's Rimbey property in Alberta.

Murphy had commitments for future capital projects of approximately \$2.13 billion at December 31, 2008, including \$172.9 million for costs to develop deepwater Gulf of Mexico fields, \$1.02 billion for field development and future work commitments in Malaysia, and \$322.5 million for field development and a work commitment in the Republic of the Congo.

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, 2008, the Company had access to a long-term committed credit facility in the amount of \$1.962 billion. A total of \$318.5 million was borrowed under the committed credit facility at year-end 2008. 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%. At December 31, 2008, the long-term debt to capital ratio was approximately 14.0%. At December 31, 2008, the Company had borrowed \$110 million under uncommitted credit lines. The Company's shelf registration on file with the U.S. Securities and Exchange Commission that permitted the offer and sale of up to \$650 million in debt and/or equity securities expired on December 31, 2008. The Company expects to file a new shelf registration in the second quarter of 2009. Current financing arrangements are set forth more fully in Note E to the consolidated financial statements. The Company anticipates matching its spending plans to cash inflows during 2009 in order to borrow little or no funds under its available credit facilities during the year. However, under a continued low price environment for oil and natural gas, the Company may have to borrow under these credit facilities to fund ongoing development projects. At February 27, 2009, the Company's long-term debt rating by Standard & Poor's was BBB and by Moody's Investors Service was Baa3. The Company has a rating of A (low) from Dominion Bond Rating Service. The Company's ratio of earnings to fixed charges was 27.9 to 1 in 2008, 14.5 to 1 in 2007 and 16.1 to 1 in 2006.

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### **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. Compliance with existing and anticipated environmental regulations affects our overall cost of business. Areas affected include capital costs to construct, maintain and upgrade equipment and facilities, in concert with ongoing operating costs for environmental compliance. Anticipated and existing regulations affect our capital expenditures and earnings, and they may affect our competitive position to the extent that regulatory requirements with respect to a particular production technology may give rise to costs that our competitors might not bear. Environmental regulations have historically been subject to frequent change by regulatory authorities, and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of such regulations on our 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 us to substantial expense, including both the cost to comply with applicable regulations and claims by neighboring landowners and other third parties for any personal injury and property damage that might result.

The most significant of those laws and the corresponding regulations affecting our U.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 the handling and disposal of solid wastes

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 wells

Regulations of the U.S. Department of the Interior governing offshore oil and gas operations.

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 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. We are 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.

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 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 our ordinary operations, we generate waste that falls within CERCLA's definition of a hazardous substance. We may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which such hazardous substances have been disposed of or released into the environment. CERCLA also requires reporting of



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releases to the environment of substances defined as hazardous or extremely hazardous and must be reported to the National Response Center, if they exceed an EPA established reportable quantity.

The EPA currently considers us to be a PRP at two Superfund sites. The potential total cost to all parties to perform necessary remedial work at these sites may be substantial. However, based on current negotiations and available information, we believe that we are a de minimis party as to ultimate responsibility at these Superfund sites. We have not recorded a liability for remedial costs on Superfund sites. We could be required to bear a pro rata share of costs attributable to nonparticipating PRPs or could be assigned additional responsibility for remediation at these sites or other Superfund sites. We believe that our share of the ultimate costs to clean-up the Superfund sites will be immaterial and will not have a material adverse effect on Murphy's net income, financial condition or liquidity in a future period.

We currently own or lease, and have in the past owned or leased, properties at which hazardous substances have been or are being handled. Although we have 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 us 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 our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws we 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, we are investigating the extent of any such liability and the availability of applicable defenses and believe costs related to these sites will not have a material adverse affect on Murphy's net income, financial condition or liquidity in a future period.

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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. We generate non-hazardous solid wastes that are subject to the requirements of RCRA and comparable state statutes. Our operating sites also incur costs to handle and dispose of hazardous waste and other chemical substances. The types of waste and substances disposed of generally fall into the following categories: spent catalysts (usually hydro-treating catalysts); spent/used filter media; tank bottoms and API separator sludge; contaminated soils; laboratory and maintenance spent solvents; and industrial debris. 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.

Murphy allocates a portion of its capital expenditure program to comply with environmental laws and regulations, and such capital expenditures were \$121.7 million in 2008 and are projected to be \$132.6 million in 2009.

Our liability for remedial obligations includes certain amounts that are based on anticipated regulatory approval for proposed remediation of former refinery waste sites. Although regulatory authorities may require more costly alternatives than the proposed processes, the cost of such potential alternative processes is not expected to exceed the accrued liability by a material amount. Certain environmental expenditures are likely to be recovered by us from other sources, primarily environmental funds maintained by certain states. Since no assurance can be given that future recoveries from other sources will occur, we have not recorded a benefit for likely recoveries as of December 31, 2008.

We are 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 our operations. Under our 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 quarterly. Actual cash expenditures often occur one or more years after a liability is recognized.

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. To the best of our knowledge, there has been no such OPA90 claims made against Murphy.

The EPA has issued several standards applicable to the formulation of motor fuels, primarily related to the level of sulfur found in highway diesel and gasoline, which are designed to reduce emissions of certain air pollutants when the fuel is used. Several states have passed similar or more stringent regulations governing the formulation of motor fuels. The EPA's mandated requirements for low-sulfur gasoline are effective in 2008 and both of our U.S. refineries have been expanded and are now capable of producing the required low-sulfur gasoline. Each of the U.S. refineries must begin to produce the EPA required ultra low-sulfur diesel (ULSD) beginning in 2010. The Meraux refinery is currently capable of producing this ULSD for approximately half of its diesel production, but the Superior refinery is not yet capable of meeting the ULSD standard. Our management is currently studying alternatives available for fully meeting this ULSD standard at Meraux and Superior.

The Energy Independence and Security Act (EISA) was signed into law in December 2007. The EIS Act 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. This Act greatly increases the renewable fuels obligation defined in the Renewable Fuels Standard 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 its obligation.

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. We maintain wastewater discharge permits for our facilities where they are required pursuant to the FWPCA and comparable state laws. We have also applied for all necessary permits to discharge storm water under such laws. We believe that compliance with existing permits and foreseeable new permit requirements will not have a material adverse effect on our net income, financial condition or liquidity in a future period.

Our U.S. operations are subject to the Federal Clean Air Act and comparable state and local statutes. We believe that our operations are in substantial compliance with these statutes in all states in which we operate. Amendments to the Federal Clean Air Act enacted in late 1990 require or will require 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.

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Under the EPA's Clean Air Act authority, the National Petroleum Refinery (NPR) Initiative (Global Consent Decree) was initiated as a national priority to investigate four marquee compliance areas for refinery operations: (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

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Standards for Hazardous Air Pollutants. Murphy, in 2005 began negotiations with the EPA, which were interrupted by the events of Hurricane Katrina. Both the state of Louisiana and Wisconsin are parties to the NPR. Negotiations with EPA resumed in 2007 and are continuing. While substantial progress has been made in these negotiations, the Company is unable at this time to predict the capital costs, operating costs and potential fines or penalties that may occur in the future upon conclusion of the NPR negotiations.

Our Meraux, Louisiana refinery is also currently negotiating with the Louisiana Department of Environmental Quality (LDEQ) regarding three Compliance Order/Notice of Proposed Penalty (CO/NOPP) notifications regarding air and water discharges. While we are in various stages of negotiations and/or settlement, the Company is unable to predict the costs that it will incur related to these CO/NOPP negotiations.

World leaders have held numerous discussions about the level of worldwide greenhouse gas emissions. As part of these discussions, the Kyoto Agreement was adopted in 1997 and was ratified by certain countries in which we operate or may operate in the future, with the United States being the primary country that has yet to ratify the agreement. The agreement became effective for ratifying countries in 2005 and these countries have implemented regulations or are in various stages of developing regulations to address its contents that ultimately target a reduction in greenhouse gas emissions. We are unable to predict how U.S. regulations (if any) associated with the Kyoto Agreement will impact costs in future years. The European Union has adopted an Emissions Trading Scheme in response to the Kyoto Agreement in order to achieve reductions in greenhouse gas emissions. Our refining operations at Milford Haven currently have 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.

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 proposed U.S. federal legislation and state actions to develop statewide or regional programs, each of which have imposed or would impose mandatory reporting and reductions in greenhouse gas emissions. These actions could result in increased costs to (i) operate and maintain our facilities; (ii) install new emission controls on our facilities; and (iii) administer and manage any greenhouse gas emissions program. These actions could also impact the consumption of refined products, thereby affecting our refinery operations. The Company is unable to predict at this time how much the cost of compliance with any future U.S. legislation or regulation of greenhouse gas emissions, if it occurs, will be in future periods. Proactively, Murphy has instituted an internal Climate Change workgroup, conducts annual greenhouse gas inventories and participates in the Massachusetts Institute of Technology (MIT) Joint Program on the Science and Policy of Global Change.

### **Safety Matters**

We are also 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 our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with OSHA requirements, including general industry standards, record-keeping requirements and monitoring of occupational exposure to regulated substances.

In 2007, OSHA announced a National Emphasis Program (NEP) for inspecting all refineries in the U.S. for compliance with OSHA's Process Safety Management (PSM) regulations. OSHA completed an inspection of our Superior, Wisconsin refinery in February 2008 and issued several compliance related citations and a penalty of \$179,000. As of December 31, 2008, all of the cited OSHA items have been abated.

### **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 to a significant extent are 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) 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 fallen significantly in late 2008 and early 2009, however, the prices for oil goods and services have not generally declined in tandem with oil and gas prices. Should a lower price environment for oil and gas continue, the Company anticipates that prices for certain equipment and services will decline due to falling demand for such items. 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** In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement applies under other accounting pronouncements that require or permit fair value measurements, and where applicable simplifies and codifies related

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guidance within GAAP and does not require any new fair value measurements. The statement was originally effective for fiscal years beginning January 1, 2008. On February 12, 2008, the FASB issued FSP No. 157-2 that delayed for one year the effective date of SFAS No. 157 for most nonfinancial assets and nonfinancial liabilities. Provisions of the statement are to be applied prospectively except in limited situations. The Company adopted this statement as of January 1, 2008 and the adoption had no material impact on its consolidated financial statements. See further disclosures at Note N to the consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS No. 159). This pronouncement permits companies with eligible financial assets and financial liabilities to measure these items at fair value in the financial statements. This option to measure at fair value is both instrument specific and irrevocable. If the fair value option is elected, certain additional disclosures are required and financial statements for periods prior to the adoption may not be restated. This pronouncement was effective January 1, 2008 for the Company. The Company chose not to elect fair value measurement for any financial assets and financial liabilities, and therefore, the adoption of SFAS No. 159, had no impact on the Company's consolidated balance sheet or consolidated statement of income.

In June 2007, the FASB ratified the Emerging Issues Task Force's Issue No. 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards (EITF 06-11). This new guidance was effective for the Company beginning January 1, 2008 and required that income tax benefits received by the Company for dividends paid on share-based incentive awards be recorded in Capital in Excess of Par Value in Stockholders' Equity. Under certain circumstances, such tax benefits received on awards that do not vest could be reclassified to reduce income tax expense in the Consolidated Statements of Income. The effect of adopting EITF No. 06-11 in 2008 was not material to the Company's consolidated financial statements.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51. This statement is effective for the Company beginning January 1, 2009. Upon adoption, this statement will require noncontrolling interests to be reclassified as equity, and consolidated net income and comprehensive income shall include the respective results attributable to noncontrolling interests. It is to be applied prospectively and early adoption is not permitted. The Company does not expect this statement to have a significant effect on its consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations. This statement establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquired business. It also establishes how to recognize and measure goodwill acquired in the business combination or a gain from a bargain purchase, if applicable. This statement shall be applied prospectively by the Company to any business combination that occurs on or after January 1, 2009. Early application is prohibited. Assets and liabilities that arise from business combinations occurring prior to 2009 shall not be adjusted upon application of this statement. This statement will impact the recognition and measurement of assets and liabilities in business combinations that occur after 2008, and the Company is unable to predict at this time how the application of this statement will affect its financial statements in future periods.

In March 2008, the FASB issued SFAS No. 161, Disclosure about Derivative Instruments and Hedging Activities. This statement is effective for the Company beginning in January 2009, and it expands required disclosures regarding derivative instruments to include qualitative information about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. The Company does not expect this statement to have a significant effect on its consolidated financial statements.

In June 2008, the FASB issued FASB Staff Position on EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities (FSP EITF 03-6-1). This statement provides that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings per share (EPS) calculation under the two-class method. All prior-period EPS calculations must be adjusted retrospectively. This statement is effective for the Company in 2009. Although the Company is in the process of evaluating this statement, it does not expect the effect of adopting this statement in 2009 to have a significant impact on its prior-period EPS calculations.

In December 2008, the FASB issued Staff Position No. FAS 132(R)-1, Employers' Disclosures about Postretirement Benefit Plan Assets. This guidance will require additional disclosures about benefit plan assets, including how asset investment allocation decisions are made, the fair value of each major category of plan assets, and how fair value is determined for each major asset category. This guidance is effective for the Company at year-end 2009. Upon adoption, no comparative disclosures are required for earlier years presented. The Company does not expect the adoption of this standard to have a material impact on its consolidated financial statements in future periods.

In November 2008, the EITF published Issue No. 08-6, Equity Method Investment Accounting Considerations. This pronouncement gives guidance about how to initially measure contingent consideration for an equity method investment, how to recognize other-than-temporary impairments of an equity method investment, and how an equity method investor is to account for a share issuance by an investee. This



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guidance is effective for the Company at the beginning of its 2009 fiscal year. The guidance is to be applied prospectively and early adoption is not permitted. The Company is currently evaluating this guidance and is unable to predict at this time how it will impact its consolidated financial statements in future periods.

**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 natural gas reserves* Proved reserves are defined by the U.S. Securities and Exchange Commission (SEC) as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. 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 year-end oil and natural gas prices must be used for determining proved reserve quantities. Year-end prices usually do not approximate the average price that the Company expects to receive for its oil and natural gas production. 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 natural 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.

The Company's proved reserves of oil and natural gas are presented on pages F-34 and F-35 of the 2008 annual report. An unfavorable U.S. oil revision in 2008 resulted from updated reservoir modeling of one field in the deepwater Gulf of Mexico. An unfavorable revision in Canada in 2008 was related to low heavy oil prices at year-end, but this was partially offset by a favorable impact from better field performance at Hibernia. A favorable oil reserve revision in Malaysia was attributable to better than anticipated drilling results and additional drilling opportunities in the main reservoir at the Kikeh field, coupled with better reservoir performance and artificial lift improvements at the West Patricia field. An unfavorable oil reserve revision in the U.S. in 2007 was mostly related to poor performance at one deepwater field in the Gulf of Mexico. Favorable oil reserve revisions in 2007 in Canada relate primarily to better performance at the Hibernia and Terra Nova fields. Favorable 2007 oil revisions in Malaysia relate to West Patricia and Kikeh well performances. The oil reserve revisions in 2006 in the U.S., Canada, Malaysia and Ecuador were based on performance of various local wells. The favorable oil reserve revision in Malaysia in 2006 was mostly due to extension of proved oil in the Kikeh reservoir. An unfavorable natural gas reserve revision in Malaysia in 2008 was related to entitlement adjustments under the Sarawak Blocks SK 309 and SK 311 production sharing contract and gas volumes lost due to operational delays that restricted sales volumes at the Kikeh field, offshore Sabah. Downward revisions to U.S. natural gas reserves in 2007 and 2006 were mostly caused by unfavorable production performance for gas wells at various fields in the Gulf of Mexico and onshore south Louisiana. The favorable natural gas reserve revision in Canada in 2007 is mostly attributable to well performance at the natural gas field owned by a consolidated subsidiary. The downward revision to 2007 natural gas reserves in Malaysia is based on higher contractual sales prices at year-end 2007 compared to 2006. The significant upward revision of natural gas reserves in Malaysia in 2006 related to gas associated with the Kikeh field that will be sold to the local government beginning in 2008. The Company cannot predict the type of reserve revisions that will be required in future periods.

On December 29, 2008, the SEC adopted revisions to oil and natural gas reserve reporting requirements which are effective for the Company at year-end 2009, unless the timing is subsequently amended. Among other things, the rule:

revises the definition of proved reserves, including the pricing used to determine economic producibility,

expands the definition of oil and gas producing activities to include non-traditional and unconventional resources, which includes the Company's synthetic oil operations in Alberta, and



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allows, but does not require, companies to disclose probable and possible reserves in SEC filings.

The Company is currently evaluating these new rules and cannot predict how the new rules will affect its future reporting of oil and natural gas reserves. The full rule is available at the SEC's website at [www.sec.gov](http://www.sec.gov).

*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.

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In some cases, a determination of whether a drilled well has found proved reserves can not 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. Dry hole expense related to wells drilled in a prior year was \$3.4 million in 2006; there were no dry holes in 2008 or 2007 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. Based on an evaluation of expected future cash flows from properties at year-end 2008, the Company does not believe it had any 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 generally reflected higher expected prices for oil and natural gas in the future compared to the existing spot prices at the end of 2008. 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 2008. 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 can not predict the amount or timing of impairment expenses that may be recorded in the future.

Murphy holds a 20% interest in Block 16 Ecuador, where the Company and its partners produce oil for export. On October 18, 2007, the government of Ecuador enacted into law a levy that increases from 50% to 99% its share of oil sales prices that exceed a threshold reference price that was about \$23.36 per barrel at December 31, 2008. The Company and its partners in Block 16 have initiated arbitration proceedings with an international arbitrator as permitted by its participation contract. While arbitration proceedings are ongoing the Block 16 partners are actively negotiating contractual changes with the Ecuadorian government. Should the arbitration, negotiations and other designated security arrangements fail to permit the Company to recover its investment, the Company could have to record an impairment charge to reduce its investment in Block 16 in a future period. The Company's carrying value of fixed assets in Ecuador amounted to \$70.7 million at December 31, 2008.

*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

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(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, PM 311/312, P, L and M in Malaysia, exploration licenses in the Republic of the Congo and Australia, and 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 adjusted as necessary, generally based on the universe of high-quality corporate bonds available within each country, and after cash flow analyses are performed to discount projected benefit payment streams. 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 2008, the Company has used a discount rate of 6.50% in 2008 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 2009 compared to 2008 based on the effects of a growing employee base. In 2008, the Company paid \$50.6 million into various retirement plans and \$4.0 million into postretirement plans. In 2009, the Company is expecting to fund payments of approximately \$50.2 million into various retirement plans and \$4.9 million for postretirement plans. The 2009 retirement plan contribution includes a currently anticipated voluntary contribution of \$30.0 million. 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 6.5%, 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 2009 annual retirement and postretirement expenses by \$3.8 million and \$0.6 million, respectively, and a 0.5% decline in the assumed rate of return on plan assets would increase 2009 retirement expense by \$1.4 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 2008 under such contractual obligations and arrangements are shown below.

| (Millions of dollars)                   | Total      | Amount of Obligation |           |           |            |
|---|------------|----------------------|-----------|-----------|------------|
|   |            | 2009                 | 2010-2011 | 2012-2013 | After 2013 |
| Total debt including current maturities | \$ 1,028.8 | 2.6                  |           | 778.1     | 248.1      |
| Operating leases                        | 813.1      | 96.3                 | 181.0     | 165.1     | 370.7      |

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|                             |            |         |         |         |         |
|-----------------------------|------------|---------|---------|---------|---------|
| Purchase obligations        | 3,186.3    | 2,124.6 | 795.6   | 161.9   | 104.2   |
| Other long-term liabilities | 630.1      | 70.9    | 42.6    | 80.6    | 436.0   |
| Total                       | \$ 5,658.3 | 2,294.4 | 1,019.2 | 1,185.7 | 1,159.0 |

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The Company has entered into an agreement to lease production facilities for the Kikeh field offshore Malaysia. 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 on the previous page.

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 amount of commitments as of December 31, 2008 that expire in future periods is shown below.

| <i>(Millions of dollars)</i> | Amount of Commitment |              |            |           |             |
|------------------------------|----------------------|--------------|------------|-----------|-------------|
|                              | Total                | 2009         | 2010- 2011 | 2012-2013 | After 2013  |
| Financial guarantees         | \$ 7.8               |              |            |           | 7.8         |
| Letters of credit            | 120.0                | 116.0        | .6         |           | 3.4         |
| <b>Total</b>                 | <b>\$ 127.8</b>      | <b>116.0</b> | <b>.6</b>  |           | <b>11.2</b> |

**Material off-balance sheet arrangements** The Company occasionally utilizes off-balance sheet arrangements for operational or funding purposes. The most significant of these arrangements at year-end 2008 includes an operating lease of the Kikeh floating, production, storage and offloading vessel (FPSO), a natural gas transportation contract for the Tupper area in British Columbia and a hydrogen purchase contract for the Meraux refinery. The Kikeh FPSO lease calls for future monthly net lease payments over the next seven years. The Tupper transportation contract requires minimum monthly payments through 2013. The Meraux refinery contract to purchase hydrogen ends in 2021. The hydrogen contract requires a monthly minimum base facility charge whether or not any hydrogen is purchased. Future required minimum annual payments under these arrangements are included in the contractual obligation table shown above.

**Outlook**

Prices for the Company's primary products are often quite volatile. A strong global economy, which fueled demand for energy, led to generally stronger prices for crude oil and refined petroleum products during 2007 and the first half of 2008. Beginning in the second half of 2008 and continuing into early 2009, crude oil prices have fallen precipitously from the highs at mid-year 2008. The decline in the prices for crude oil is primarily attributable to softening demand for energy associated with the worldwide economic downturn. Due to the weak prices for crude oil and North American natural gas prices, the Company is making substantial efforts to balance its cash flow and spending in early 2009.

The Company's capital expenditure budget for 2009 was prepared during the fall of 2008 and based on this budget capital expenditures are expected to be below 2008 levels. Since the budget was approved by the Company's Board of Directors, crude oil and North American natural gas prices have generally been below the levels assumed in the 2009 budget. Based on a recent review of capital expenditure projects, capital expenditures in 2009 are projected to total approximately \$2 billion. Of this amount, \$1.7 billion or about 87%, is allocated for the exploration and production program. Geographically, E&P capital is spread approximately as follows: 16% for the United States, 42% for Malaysia, 23% for Canada and 19% for all other areas. Spending in the U.S. is primarily associated with continued development of producing and nonproducing deepwater fields as well as for the Company's Gulf of Mexico exploration program. In Malaysia, the majority of the spending is for continued development of natural gas fields in Blocks SK 309 and 311 offshore Sarawak where first production is anticipated in 2009 and the Kakap field in Block K. The bulk of Canadian spending in 2008 will relate to natural gas development at Tupper in Western Canada. Spending in the Republic of the Congo includes continuing development costs for the Azurite discovery offshore, which is scheduled to start production in mid-2009. Refining and marketing expenditures in 2009 should be about \$250 million, including funds for construction of additional U.S. retail gasoline stations and early costs for an expansion of the crude unit at the Milford Haven, Wales refinery. Capital and other expenditures will be routinely reviewed during 2009 and planned capital expenditures may be adjusted to reflect differences between budgeted and actual cash flow during the year. Capital expenditures may also be affected by asset purchases, which often are not anticipated at the time the Budget is prepared.

The Company will primarily fund its capital program in 2009 using operating cash flow, but will supplement funding where necessary using borrowings under available credit facilities. The Company will endeavor to have no increase in long-term debt in 2009, but a continued low price environment could reduce actual cash flow generated from operations to such a level that borrowings might be required during the year to maintain funding of the Company's ongoing development projects. As noted earlier, crude oil and North American natural gas prices in early 2009 were well below the levels assumed in the 2009 budget. Also, through early 2009, margins within the Company's refining and marketing operations were generally below amounts included in the Company's 2009 budget.

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The Company currently expects production in 2009 to average about 180,000 barrels of oil equivalent per day. A key assumption in projecting the level of 2009 Company production is the anticipated ramp up of natural gas production from Tupper in western Canada and Kikeh offshore Sabah Malaysia, and start-up of natural gas production offshore Sarawak Malaysia. In addition, continued reliability of production at significant fields such as Kikeh, Syncrude, Hibernia and Terra Nova are necessary to achieve the anticipated 2009 production levels.

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### **Forward-Looking Statements**

This Form 10-K report, including documents incorporated by reference here, contains statements of the Company's expectations, intentions, plans and beliefs that are forward-looking and are dependent on certain events, risks and uncertainties that may be outside of the Company's control. These forward-looking statements are made in reliance upon the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Actual results and developments could differ materially from those expressed or implied by such statements due to a number of factors including those described in the context of such forward-looking statements as well as those contained in the Company's January 15, 1997 Form 8-K report on file with the U.S. Securities and Exchange Commission.

### **Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

The Company is exposed to market risks associated with interest rates, prices of crude oil, natural gas and petroleum products, and foreign currency exchange rates. As described in Note A to the consolidated financial statements, Murphy makes limited use of derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions.

Murphy was a party to short-term derivative instruments at December 31, 2008 for a notional amount of approximately 1.1 million barrels of oil that are intended to manage the price of certain Superior, Wisconsin refinery crude oil to be purchased in 2009. These contracts were marked to market at year-end 2008 with a pretax charge of \$1.4 million. A 10% increase in the price of crude oil would have improved pretax income in 2008 by \$4.2 million, while a 10% decrease in the price of crude oil would have reduced 2008 pretax income by \$4.2 million.

### **Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA**

Information required by this item appears on pages F-1 through F-41, which follow page 37 of this Form 10-K report.

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

None

### **Item 9A. CONTROLS AND PROCEDURES**

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

Based on their evaluation, with the participation of the Company's management, as of December 31, 2008, the principal executive officer and principal financial officer of Murphy Oil Corporation have concluded that the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective to ensure that the information required to be disclosed by Murphy Oil Corporation in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Murphy's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Management has conducted an evaluation of the effectiveness of our internal control over financial reporting based on the criteria set forth in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, management has concluded that our internal control over financial reporting was effective as of December 31, 2008. Our report is included on page F-2 of the annual report. KPMG LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2008 and their report is also included on page F-2 of this annual report.

There were no changes in the Company's internal controls over financial reporting that occurred during the fourth quarter of 2008 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.



**Item 9B. OTHER INFORMATION**

None

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**PART III**

**Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE**

Certain information regarding executive officers of the Company is included on page 11 of this Form 10-K report. Other information required by this item is incorporated by reference to the Registrant's definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2009 under the captions "Election of Directors" and "Committees."

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

**Item 11. EXECUTIVE COMPENSATION**

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2009 under the captions "Compensation Discussion and Analysis" and "Compensation of Directors," and in various compensation schedules.

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

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2009 under the captions "Security Ownership of Certain Beneficial Owners," "Security Ownership of Management," and "Equity Compensation Plan Information."

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

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2009 under the caption "Election of Directors."

**Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES**

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2009 under the caption "Audit Committee Report."

**PART IV**

**Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES**

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

**Page No.**

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|   |      |
|---|------|
| <u>Report of Management – Consolidated Financial Statements</u>         | F-1  |
| <u>Report of Independent Registered Public Accounting Firm</u>          | F-1  |
| <u>Report of Management – Internal Control Over Financial Reporting</u> | F-2  |
| <u>Report of Independent Registered Public Accounting Firm</u>          | F-2  |
| <u>Consolidated Statements of Income</u>                                | F-3  |
| <u>Consolidated Balance Sheets</u>                                      | F-4  |
| <u>Consolidated Statements of Cash Flows</u>                            | F-5  |
| <u>Consolidated Statements of Stockholders’ Equity</u>                  | F-6  |
| <u>Consolidated Statements of Comprehensive Income</u>                  | F-7  |
| <u>Notes to Consolidated Financial Statements</u>                       | F-8  |
| <u>Supplemental Oil and Gas Information (unaudited)</u>                 | F-32 |
| <u>Supplemental Quarterly Information (unaudited)</u>                   | F-41 |

**Table of Contents****2. Financial Statement Schedules**

**Page No.**  
F-42

Schedule II Valuation Accounts and Reserves

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

- 3. Exhibits** The following is an index of exhibits that are hereby filed as indicated by asterisk (\*), that are to be filed by an amendment as indicated by pound sign (#), or that are incorporated by reference. Exhibits other than those listed have been omitted since they either are not required or are not applicable.

| <b>Exhibit No.</b> |  | <b>Incorporated by Reference to</b>  |
|--------------------|--|--|
| 3.1                | Certificate of Incorporation of Murphy Oil Corporation as amended, effective May 11, 2005  | Exhibit 3.1 of Murphy's Form 10-Q report for the quarterly period ended June 30, 2005  |
| 3.2                | By-Laws of Murphy Oil Corporation as amended effective August 6, 2008  | Exhibit 3.2 of Murphy's Form 8-K filed August 6, 2008                                  |
| 4                  | Instruments Defining the Rights of Security Holders. Murphy is party to several long-term debt instruments in addition to those in Exhibit 4.1 and 4.2, none of which authorizes securities exceeding 10% of the total consolidated assets of Murphy and its subsidiaries. Pursuant to Regulation S-K, item 601(b), paragraph 4(iii)(A), Murphy agrees to furnish a copy of each such instrument to the Securities and Exchange Commission upon request. |  |
| *4.1               | Form of Second Supplemental Indenture between Murphy Oil Corporation and SunTrust Bank, as Trustee   |  |
| 4.2                | Form of Indenture and Form of Supplemental Indenture between Murphy Oil Corporation and SunTrust Bank, as Trustee  | Exhibit 4.2 of Murphy's Form 10-K report for the year ended December 31, 2004          |
| 4.3                | Rights Agreement dated as of December 6, 1989 between Murphy Oil Corporation and Harris Trust Company of New York, as Rights Agent   | Exhibit 4.3 of Murphy's Form 10-K report for the year ended December 31, 2004          |
| 4.4                | Amendment No. 1 dated as of April 6, 1998 to Rights Agreement dated as of December 6, 1989 between Murphy Oil Corporation and Harris Trust Company of New York, as Rights Agent  | Exhibit 4.4 of Murphy's Form 10-K report for the year ended December 31, 2004          |
| 4.5                | Amendment No. 2 dated as of April 15, 1999 to Rights Agreement dated as of December 6, 1989 between Murphy Oil Corporation and Harris Trust Company of New York, as Rights Agent   | Exhibit 4.5 of Murphy's Form 10-K report for the year ended December 31, 2004          |
| 10.1               | 1992 Stock Incentive Plan as amended May 14, 1997, December 1, 1999, May 14, 2003 and December 7, 2005   | Exhibit 10.1 of Murphy's Form 10-K report for the year ended December 31, 2005         |
| 10.2               | 2007 Long-Term Incentive Plan  | Exhibit 10.1 of Murphy's Form 8-K report filed April 24, 2007                          |
| 10.3               | Employee Stock Purchase Plan as amended May 9, 2007  | Exhibit C of Murphy's definitive proxy statement (Definitive 14A) dated March 30, 2007 |
| 10.4               |  | Form S-8 report filed February 5, 2009   |

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2008 Stock Plan for Non-Employee Directors, as approved  
by shareholders on May 14, 2008

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| <b>Exhibit No.</b> |   | <b>Incorporated by Reference to</b>   |
|--------------------|---|---|
| 10.5a              | Floating, Production, Storage and Offloading vessel charter contract for Kikeh field                                    | Exhibit 10.5a of Murphy s Form 10-K report for the year ended December 31, 2004 |
| 10.5b              | Floating, Production, Storage and Offloading vessel operating and maintenance agreement for Kikeh field                 | Exhibit 10.5b of Murphy s Form 10-K report for the year ended December 31, 2004 |
| 10.6               | Dry Tree Unit contract for Kikeh field  | Exhibit 10.6 of Murphy s Form 10-K report for the year ended December 31, 2004  |
| *12.1              | Computation of Ratio of Earnings to Fixed Charges   |   |
| *13                | 2008 Annual Report to Security Holders  |   |
| *21                | Subsidiaries of the Registrant  |   |
| *23                | Consent of Independent Registered Public Accounting Firm  |   |
| *31.1              | Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002                      |   |
| *31.2              | Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002                      |   |
| 32                 | Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 | See footnote <sup>1</sup> below.  |
| 99.1               | Form of employee stock option   | Exhibit 99.1 of Murphy s Form 10-K report for the year ended December 31, 2005  |
| *99.2              | Form of performance-based employee restricted stock unit grant agreement  |   |
| 99.3               | Form of non-employee director stock option  | Exhibit 99.3 of Murphy s Form 10-K report for the year ended December 31, 2005  |
| 99.4               | Form of non-employee director restricted stock award  | Exhibit 99.4 of Murphy s Form 10-K report for the year ended December 31, 2006  |
| *99.5              | Form of non-employee director restricted stock unit award   |   |

<sup>1</sup> These certifications will not be deemed to be filed with the Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

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**SIGNATURES**

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

MURPHY OIL CORPORATION

By: **DAVID M. WOOD** Date: **February 27, 2009**  
David M. Wood, President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 27, 2009 by the following persons on behalf of the registrant and in the capacities indicated.

**WILLIAM C. NOLAN JR.**  
William C. Nolan Jr., Chairman and Director

**IVAR B. RAMBERG**  
Ivar B. Ramberg, Director

**DAVID M. WOOD**  
David M. Wood, President and Chief  
Executive Officer and Director  
(Principal Executive Officer)

**NEAL E. SCHMALE**  
Neal E. Schmale, Director

**FRANK W. BLUE**  
Frank W. Blue, Director

**DAVID J. H. SMITH**  
David J. H. Smith, Director

**CLAIBORNE P. DEMING**  
Claiborne P. Deming, Director

**CAROLINE G. THEUS**  
Caroline G. Theus, Director

**ROBERT A. HERMES**  
Robert A. Hermes, Director

**KEVIN G. FITZGERALD**  
Kevin G. Fitzgerald, Senior Vice President  
and Chief Financial Officer  
(Principal Financial Officer)

**JAMES V. KELLEY**  
James V. Kelley, Director

**JOHN W. ECKART**  
John W. Eckart  
Vice President and Controller  
(Principal Accounting Officer)

**R. MADISON MURPHY**  
R. Madison Murphy, Director

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**REPORT OF MANAGEMENT CONSOLIDATED FINANCIAL STATEMENTS**

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

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

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

Our report of management covering internal control over financial reporting and the associated report of the independent registered public accounting firm can be found at page F-2.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

The Board of Directors and Stockholders of Murphy Oil Corporation:

We have audited the accompanying consolidated balance sheets of Murphy Oil Corporation and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of income, comprehensive income, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2008. In connection with our audits of the consolidated financial statements, we also have audited financial statement Schedule II. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Murphy Oil Corporation and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note B to the consolidated financial statements, effective December 31, 2006, the Company changed its accounting for recognition of defined benefit pension and other postretirement plans. As also discussed in Note B to the consolidated financial statements, effective January 1, 2007, the Company changed its accounting for uncertain tax positions, and measurement of defined benefit pension and other postretirement plans.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Murphy Oil Corporation's internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2009 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.



Houston, Texas  
February 27, 2009

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### **REPORT OF MANAGEMENT INTERNAL CONTROL OVER FINANCIAL REPORTING**

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

Management has conducted an evaluation of the effectiveness of our internal control over financial reporting based on the criteria set forth in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2008.

### **REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

The Board of Directors and Stockholders of Murphy Oil Corporation:

We have audited Murphy Oil Corporation's internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Murphy Oil Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Report of Management Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Murphy Oil Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Murphy Oil Corporation as of December 31, 2008 and 2007, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2008, and our report dated February 27, 2009 expressed an unqualified opinion on those consolidated financial statements.

Houston, Texas

February 27, 2009

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**Table of Contents****MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****CONSOLIDATED STATEMENTS OF INCOME**

| Years Ended December 31 (Thousands of dollars except per share amounts) | 2008                | 2007              | 2006              |
|---|---------------------|-------------------|-------------------|
| <b>Revenues</b>   |                     |                   |                   |
| Sales and other operating revenues                                      | \$ 27,440,834       | 18,423,771        | 14,279,325        |
| Gain (loss) on sale of assets   | 133,717             | (365)             | 9,388             |
| Interest and other income (loss)  | (62,011)            | 15,692            | 18,674            |
| <b>Total revenues</b>   | <b>27,512,540</b>   | <b>18,439,098</b> | <b>14,307,387</b> |
| <b>Costs and Expenses</b>   |                     |                   |                   |
| Crude oil and product purchases   | 21,649,742          | 14,882,618        | 11,214,235        |
| Operating expenses  | 1,688,576           | 1,312,030         | 1,093,213         |
| Exploration expenses, including undeveloped lease amortization          | 344,406             | 203,065           | 219,238           |
| Selling and general expenses  | 229,802             | 229,300           | 228,543           |
| Depreciation, depletion and amortization                                | 713,002             | 489,837           | 384,063           |
| Impairment of properties  |                     | 40,708            |                   |
| Accretion of asset retirement obligations                               | 24,484              | 16,244            | 10,921            |
| Net costs associated with hurricanes                                    |                     | 3,000             | 109,244           |
| Interest expense  | 75,138              | 75,493            | 52,549            |
| Interest capitalized  | (31,459)            | (49,881)          | (43,073)          |
| Minority interest   | 298                 | (548)             | 56                |
| <b>Total costs and expenses</b>   | <b>24,693,989</b>   | <b>17,201,866</b> | <b>13,268,989</b> |
| <b>Income before income taxes</b>                                       | <b>2,818,551</b>    | <b>1,237,232</b>  | <b>1,038,398</b>  |
| <b>Income tax expense</b>   | <b>1,078,565</b>    | <b>470,703</b>    | <b>393,729</b>    |
| <b>Net Income</b>   | <b>\$ 1,739,986</b> | <b>766,529</b>    | <b>644,669</b>    |
| <b>Net Income per Common share</b>                                      |                     |                   |                   |
| <b>Basic</b>  | <b>\$ 9.18</b>      | <b>4.08</b>       | <b>3.46</b>       |
| <b>Diluted</b>  | <b>\$ 9.06</b>      | <b>4.01</b>       | <b>3.41</b>       |
| Average Common shares outstanding basic                                 | 189,608,846         | 188,027,557       | 186,105,086       |
| Average Common shares outstanding diluted                               | 192,133,672         | 191,140,737       | 189,158,411       |

See notes to consolidated financial statements, page F-8.

**Table of Contents****MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****CONSOLIDATED BALANCE SHEETS**

| <b>December 31 (Thousands of dollars)</b>   | <b>2008</b>   | <b>2007</b> |
|---|---------------|-------------|
| <b>Assets</b>   |               |             |
| Current assets  |               |             |
| Cash and cash equivalents   | \$ 666,110    | 673,707     |
| Canadian government securities with maturities greater than 90 days at the date of acquisition  | 420,340       |             |
| Accounts receivable, less allowance for doubtful accounts of \$7,303 in 2008 and \$7,484 in 2007  | 1,033,996     | 1,420,601   |
| Inventories, at lower of cost or market   |               |             |
| Crude oil and blend stocks  | 98,217        | 159,379     |
| Finished products   | 315,340       | 315,977     |
| Materials and supplies  | 190,616       | 151,291     |
| Prepaid expenses  | 92,544        | 79,585      |
| Deferred income taxes   | 29,801        | 86,252      |
| Total current assets  | 2,846,964     | 2,886,792   |
| Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of \$3,824,393 in 2008 and \$3,516,338 in 2007                                   | 7,727,718     | 7,109,822   |
| Goodwill  | 37,370        | 51,450      |
| Deferred charges and other assets   | 537,046       | 487,785     |
| Total assets  | \$ 11,149,098 | 10,535,849  |
| <b>Liabilities and Stockholders' Equity</b>   |               |             |
| Current liabilities   |               |             |
| Current maturities of long-term debt  | \$ 2,572      | 5,208       |
| Notes payable   |               | 7,561       |
| Accounts payable  | 1,174,623     | 1,662,401   |
| Income taxes payable  | 451,372       | 108,783     |
| Other taxes payable   | 152,038       | 199,809     |
| Other accrued liabilities   | 107,541       | 125,500     |
| Total current liabilities   | 1,888,146     | 2,109,262   |
| Notes payable   | 1,026,222     | 1,513,015   |
| Nonrecourse debt of a subsidiary  |               | 3,141       |
| Deferred income taxes   | 878,131       | 916,910     |
| Asset retirement obligations  | 435,589       | 336,107     |
| Deferred credits and other liabilities  | 642,065       | 564,374     |
| Minority interest   |               | 26,866      |
| Stockholders' equity  |               |             |
| Cumulative Preferred Stock, par \$100, authorized 400,000 shares, none issued   |               |             |
| Common Stock, par \$1.00, authorized 450,000,000 shares at December 31, 2008 and 2007, issued 191,248,941 shares at December 31, 2008 and 189,972,970 shares at December 31, 2007 | 191,249       | 189,973     |
| Capital in excess of par value  | 631,859       | 547,185     |
| Retained earnings   | 5,557,483     | 3,983,998   |
| Accumulated other comprehensive income  | (87,697)      | 351,765     |
| Treasury stock  | (13,949)      | (6,747)     |
| Total stockholders' equity  | 6,278,945     | 5,066,174   |
| Total liabilities and stockholders' equity  | \$ 11,149,098 | 10,535,849  |

See notes to consolidated financial statements, page F-8.

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**Table of Contents****MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****CONSOLIDATED STATEMENTS OF CASH FLOWS**

| <b>Years Ended December 31 (Thousands of dollars)</b>                            | <b>2008</b>        | <b>2007</b>        | <b>2006</b>        |
|--|--------------------|--------------------|--------------------|
| <b>Operating Activities</b>  |                    |                    |                    |
| Net income   | \$ 1,739,986       | 766,529            | 644,669            |
| Adjustments to reconcile net income to net cash provided by operating activities |                    |                    |                    |
| Depreciation, depletion and amortization   | 713,002            | 489,837            | 384,063            |
| Impairment of long-lived assets  |                    | 40,708             |                    |
| Amortization of deferred major repair costs                                      | 27,294             | 22,107             | 17,720             |
| Expenditures for asset retirements   | (9,240)            | (13,039)           | (3,328)            |
| Dry hole costs   | 129,459            | 67,052             | 111,044            |
| Amortization of undeveloped leases   | 112,052            | 33,215             | 22,466             |
| Accretion of asset retirement obligations  | 24,484             | 16,244             | 10,921             |
| Deferred and noncurrent income tax charges                                       | 233,076            | 102,507            | 33,091             |
| Pretax (gains) losses from disposition of assets                                 | (133,717)          | 365                | (9,388)            |
| Net decrease (increase) in noncash operating working capital                     | 168,212            | 145,454            | (255,970)          |
| Other operating activities net   | 35,304             | 69,441             | 20,190             |
| <b>Net cash provided by operating activities</b>                                 | <b>3,039,912</b>   | <b>1,740,420</b>   | <b>975,478</b>     |
| <b>Investing Activities</b>  |                    |                    |                    |
| Property additions and dry hole costs  | (2,185,960)        | (1,949,219)        | (1,191,670)        |
| Acquisition of Milford Haven refinery, including inventory                       |                    | (348,292)          |                    |
| Proceeds from sale of property, plant and equipment                              | 361,961            | 21,636             | 23,843             |
| Expenditures for major repairs   | (57,604)           | (14,649)           | (12,776)           |
| Purchase of investment securities*   | (1,043,473)        |                    |                    |
| Proceeds from maturity of investment securities*                                 | 623,133            |                    |                    |
| Other investing activities net   | (21,256)           | 4,011              | (10,839)           |
| <b>Net cash required by investing activities</b>                                 | <b>(2,323,199)</b> | <b>(2,286,513)</b> | <b>(1,191,442)</b> |
| <b>Financing Activities</b>  |                    |                    |                    |
| Additions to notes payable   |                    | 686,194            | 237,658            |
| Reductions of notes payable  | (487,612)          | (825)              | (14)               |
| Reductions of nonrecourse debt of a subsidiary                                   | (5,235)            | (4,903)            | (4,667)            |
| Proceeds from exercise of stock options and employee stock purchase plans        | 29,687             | 41,624             | 24,864             |
| Excess tax benefits related to exercise of stock options                         | 20,288             | 30,805             | 11,756             |
| Cash dividends paid  | (166,501)          | (127,353)          | (98,162)           |
| Other financing activities net   |                    | (760)              |                    |
| <b>Net cash provided (required) by financing activities</b>                      | <b>(609,373)</b>   | <b>624,782</b>     | <b>171,435</b>     |
| Effect of exchange rate changes on cash and cash equivalents                     | (114,937)          | 51,628             | 2,586              |
| Net increase (decrease) in cash and cash equivalents                             | (7,597)            | 130,317            | (41,943)           |
| Cash and cash equivalents at January 1   | 673,707            | 543,390            | 585,333            |
| <b>Cash and cash equivalents at December 31</b>                                  | <b>\$ 666,110</b>  | <b>673,707</b>     | <b>543,390</b>     |

\* Represents cash invested in Canadian government securities with maturities greater than 90 days at the date of acquisition.

See notes to consolidated financial statements, page F-8.

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**Table of Contents****MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY**

| Years Ended December 31 ( <i>Thousands of dollars</i> )   | 2008       | 2007      | 2006      |
|---|------------|-----------|-----------|
| <b>Cumulative Preferred Stock</b> par \$100, authorized 400,000 shares, none issued   |            |           |           |
| <b>Common Stock</b> par \$1.00, authorized 450,000,000 shares at December 31, 2008, 2007 and 2006, issued 191,248,941 shares at December 31, 2008, 189,972,970 shares at December 31, 2007, and 187,691,508 shares at December 31, 2006 |            |           |           |
| Balance at beginning of year  | \$ 189,973 | 187,692   | 186,829   |
| Exercise of stock options   | 1,276      | 2,281     | 863       |
| Balance at end of year  | 191,249    | 189,973   | 187,692   |
| <b>Capital in Excess of Par Value</b>   |            |           |           |
| Balance at beginning of year  | 547,185    | 454,860   | 437,963   |
| Exercise of stock options, including income tax benefits  | 45,839     | 63,702    | 23,956    |
| Restricted stock transactions and other   | 7,089      | 3,794     | (1,390)   |
| Amortization, forfeitures and other   | 30,811     | 23,784    | 10,180    |
| Sale of stock under employee stock purchase plans   | 935        | 1,045     | 561       |
| Reclassification from Unamortized Restricted Stock Awards upon adoption of SFAS No. 123R  |            |           | (16,410)  |
| Balance at end of year  | 631,859    | 547,185   | 454,860   |
| <b>Retained Earnings</b>  |            |           |           |
| Balance at beginning of year  | 3,983,998  | 3,349,832 | 2,803,325 |
| Cumulative effect of changes in accounting principles   |            | (5,010)   |           |
| Net income for the year   | 1,739,986  | 766,529   | 644,669   |
| Cash dividends \$ .875 per share in 2008, \$.675 per share in 2007 and \$.525 per share in 2006   | (166,501)  | (127,353) | (98,162)  |
| Balance at end of year  | 5,557,483  | 3,983,998 | 3,349,832 |
| <b>Accumulated Other Comprehensive Income</b>   |            |           |           |
| Balance at beginning of year  | 351,765    | 131,999   | 133,353   |
| Cumulative effect of changes in accounting principles   |            | 1,345     |           |
| Foreign currency translation gains (losses), net of income taxes  | (383,021)  | 204,266   | 37,143    |
| Cash flow hedging gains, net of income taxes  |            |           | 13,459    |
| Retirement and postretirement benefit plan adjustments, net of income taxes   | (56,441)   | 14,155    | (819)     |
| Adjustment to initially apply SFAS No. 158, net of income taxes   |            |           | (51,137)  |
| Balance at end of year  | (87,697)   | 351,765   | 131,999   |
| <b>Unamortized Restricted Stock Awards</b>  |            |           |           |
| Balance at beginning of year  |            |           | (16,410)  |
| Reclassification to Capital in Excess of Par Value upon adoption of SFAS No. 123R   |            |           | 16,410    |
| Balance at end of year  |            |           |           |
| <b>Treasury Stock</b>   |            |           |           |
| Balance at beginning of year  | (6,747)    | (3,110)   | (22,990)  |
| Exercise of stock options   |            |           | 13,345    |
| Sale of stock under employee stock purchase plans   | 515        | 982       | 737       |
| Awarded restricted stock, net of forfeitures  | (7,717)    | (4,619)   | 5,798     |

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|                           |   |                     |           |           |
|---------------------------|---|---------------------|-----------|-----------|
| Balance at end of year    | 535,135 shares of Common Stock in 2008, 258,821 shares in 2007 and 119,308 shares in 2006 | (13,949)            | (6,747)   | (3,110)   |
| <b>Total Stockholders</b> | <b>Equity</b>   | <b>\$ 6,278,945</b> | 5,066,174 | 4,121,273 |

See notes to consolidated financial statements, page F-8.

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**Table of Contents****MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| <b>Years Ended December 31 (Thousands of dollars)</b> | <b>2008</b>         | <b>2007</b> | <b>2006</b> |
|---|---------------------|-------------|-------------|
| Net income  | <b>\$ 1,739,986</b> | 766,529     | 644,669     |
| Other comprehensive income (loss), net of tax         |                     |             |             |
| Cash flow hedges                                      |                     |             |             |
| Net derivative losses                                 |                     |             | (5,154)     |
| Reclassification to income                            |                     |             | 18,613      |
| Total cash flow hedges                                |                     |             | 13,459      |
| Net gain (loss) from foreign currency translation     | <b>(383,021)</b>    | 204,266     | 37,143      |
| Retirement and postretirement plan adjustments        | <b>(56,441)</b>     | 14,155      | (819)       |
| Other comprehensive income (loss)                     | <b>(439,462)</b>    | 218,421     | 49,783      |
| Comprehensive Income                                  | <b>\$ 1,300,524</b> | 984,950     | 694,452     |

See notes to consolidated financial statements, page F-8.

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**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

The consolidated financial statements for the year ended December 31, 2008 include exploration expense of \$31,100,000 (with no tax benefit thereon) related to the unsuccessful drilling of the Abalone Deep #1 well offshore Western Australia that was completed in early 2009. The 2008 consolidated financial statements have been amended from those furnished to the U.S. Securities and Exchange Commission on Form 8-K on January 28, 2009 to include this additional exploration expense.

**Note A Significant Accounting Policies**

**NATURE OF BUSINESS** Murphy Oil Corporation is an international oil and gas company that conducts its business through various operating subsidiaries. The Company produces oil and/or natural gas in the United States, Canada, the United Kingdom, Malaysia and Ecuador and conducts oil and natural gas exploration activities worldwide. The Company has an interest in a Canadian synthetic oil operation, owns two petroleum refineries in the United States and one refinery in the United Kingdom. Murphy markets petroleum products under various brand names and to unbranded wholesale customers in the United States and United Kingdom.

**PRINCIPLES OF CONSOLIDATION** The consolidated financial statements include the accounts of Murphy Oil Corporation and all majority-owned subsidiaries. For consolidated subsidiaries that are less than wholly owned, the minority interest is reflected in the balance sheet as a liability. Undivided interests in oil and gas joint ventures are consolidated on a proportionate basis. Investments in affiliates in which the Company owns from 20% to 50% are accounted for by the equity method. Other investments are generally carried at cost. All significant intercompany accounts and transactions have been eliminated.

**REVENUE RECOGNITION** Revenues from sales of crude oil, natural gas and refined petroleum products are recorded when deliveries have occurred and legal ownership of the commodity transfers to the customer. Title transfers for crude oil, natural gas and bulk refined products generally occur at pipeline custody points or when a tanker lifting has occurred. Refined products sold at retail are recorded when the customer takes delivery at the pump. Merchandise revenues are recorded at the point of sale. Revenues from the production of oil and natural gas properties in which Murphy shares an undivided interest with other producers are recognized based on the actual volumes sold by the Company during the period. Gas imbalances occur when the Company's actual sales differ from its entitlement under existing working interests. The Company records a liability for gas imbalances when it has sold more than its working interest of gas production and the estimated remaining reserves make it doubtful that partners can recoup their share of production from the field. At December 31, 2008 and 2007, the liabilities for natural gas balancing were immaterial.

The Company enters into buy/sell and similar arrangements when crude oil and other petroleum products are held at one location but are needed at a different location. The Company often pays or receives funds related to the buy/sell arrangement based on location or quality differences. The Company accounts for such transactions on a net basis in its consolidated statement of income.

**TAXES COLLECTED FROM CUSTOMERS AND REMITTED TO GOVERNMENT AUTHORITIES** Excise and other taxes collected on sales of refined products and remitted to governmental agencies are excluded from revenues and costs and expenses in the Consolidated Statement of Income.

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

**MARKETABLE SECURITIES** The Company classifies investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities. The Company does not have any investments classified as trading. Available-for-sale securities are carried at fair value with the unrealized gain or loss, net of tax, reported in other comprehensive income. Held-to-maturity securities are recorded at amortized cost. Premiums and discounts are amortized or accreted into earnings over the life of the related available-for-sale or held-to-maturity security. Dividend and interest income is recognized when earned. Unrealized losses considered to be other than temporary are recognized currently in earnings. The cost of securities sold is based on the specific identification method. The fair value of investment securities is determined by available market prices. At December 31, 2008, the Company owned Canadian government securities with maturities greater than 90 days at date of acquisition that had a carrying value of \$420,340,000.

**ACCOUNTS RECEIVABLE** The Company's accounts receivable primarily consists of amounts owed to the Company by customers for sales of crude oil, natural gas and refined products under varying credit arrangements. The allowance for doubtful accounts is the Company's best

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estimate of the amount of probable credit losses on these receivables. The Company reviews this allowance for adequacy at least quarterly and bases its assessment on a combination of current information about its customers and historical write-off experience.

**PROPERTY, PLANT AND EQUIPMENT** The Company uses the successful efforts method to account for exploration and development expenditures. Leasehold acquisition costs are capitalized. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties. Costs of undeveloped leases are generally expensed over the life of the leases. Exploratory well costs are capitalized pending determination about whether proved reserves have been found. In certain cases, a determination of whether a drilled exploratory well has found proved reserves can not be made immediately. This is generally due to the need for a major capital expenditure to produce and/or evacuate the hydrocarbon(s) found. The determination of whether to make such a capital expenditure is usually dependent on whether further exploratory wells find a sufficient quantity of additional reserves. Using guidance issued in FASB Staff Position 19-1 (FSP 19-1),

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Accounting for Suspended Well Costs, the Company continues to capitalize exploratory well costs in Property, Plant and Equipment when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The Company reevaluates its capitalized drilling costs at least annually to ascertain whether drilling costs continue to qualify for ongoing capitalization. Other exploratory costs, including geological and geophysical costs, are charged to expense as incurred. Development costs, including unsuccessful development wells, are capitalized. Interest is capitalized on development projects that are expected to take one year or more to complete.

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

Asset retirement obligations (ARO) are accounted for using SFAS No. 143, Accounting for Asset Retirement Obligations, which requires the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The ARO liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when a well is drilled or the asset is placed in service. The ARO liability is estimated by the Company's engineers using existing regulatory requirements and anticipated future inflation rates. When the liability is initially recorded, the Company increases the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is increased over time to reflect the change in its present value, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Actual costs of asset retirements such as dismantling oil and gas production facilities and site restoration are charged against the related liability. Any difference between costs incurred upon settlement of an asset retirement obligation and the recorded liability is recognized as a gain or loss in the Company's earnings.

Depreciation and depletion of producing oil and gas properties is recorded based on units of production. Unit rates are computed for unamortized exploration drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. Asset retirement costs are amortized over proved reserves using the units of production method. As more fully described on page F-32 of this Form 10-K report, proved reserves are estimated by the Company's engineers and are subject to future revisions based on availability of additional information. Refineries and certain marketing facilities are depreciated primarily using the composite straight-line method with depreciable lives ranging from 14 to 25 years. Gasoline stations and other properties are depreciated over 3 to 20 years by individual unit on the straight-line method. Gains and losses on asset disposals or retirements are included in income as a separate component of revenues.

Turnarounds for major processing units are scheduled at four to five year intervals at the Company's three refineries. Turnarounds for coking units at Syncrude Canada Ltd. are scheduled at intervals of two to three years. Turnaround work associated with various other less significant units at the Company's refineries and Syncrude will vary depending on operating requirements and events. Murphy defers turnaround costs incurred and amortizes such costs through Operating Expenses over the period until the next scheduled turnaround. All other maintenance and repairs are expensed as incurred. Renewals and betterments are capitalized.

**INVENTORIES** Unsold crude oil production is carried in inventory at the lower of cost, generally applied on a first-in, first-out (FIFO) basis, or market, and include costs incurred to bring the inventory to its existing condition. Refinery inventories of crude oil and other feedstocks and finished product inventories are valued at the lower of cost, generally applied on a last-in, first-out (LIFO) basis, or market. Inventory held for resale at retail marketing stations is generally carried at average cost and is included in Finished Products Inventory. Materials and supplies are valued at the lower of average cost or estimated value and generally consist of tubulars and other drilling equipment as well as spare parts for refinery operations. Cash collected upon the sale of inventory to customers is classified as an operating activity in the Consolidated Statement of Cash Flows.

**GOODWILL** Goodwill is recorded in an acquisition when the purchase price exceeds the fair value of net assets acquired. All recorded goodwill arose from the purchase of Beau Canada Exploration Ltd. by the Company's wholly owned Canadian subsidiary in 2000. In accordance with SFAS No. 142, Goodwill and Other Intangible Assets, goodwill is not amortized. SFAS No. 142 requires an annual assessment of recoverability of the carrying value of goodwill. The Company assesses goodwill recoverability at each year-end by comparing the fair value of net assets for conventional oil and natural gas properties in Canada with the carrying value of these net assets including goodwill. The fair value of the conventional oil and natural gas reporting unit is determined using the expected present value of future cash flows. The change in the carrying value of goodwill during 2008 was caused by a change in the foreign currency translation rate between years and sale of certain assets in Canada during the year. Based on its assessment of the fair value of its Canadian conventional oil and natural gas operations, the Company believes the recorded value of goodwill is not impaired at December 31, 2008. Should a future assessment indicate that goodwill is not fully recoverable, an impairment charge to write down the carrying value of goodwill would be required.

**ENVIRONMENTAL LIABILITIES** A liability for environmental matters is established when it is probable that an environmental obligation exists and the cost can be reasonably estimated. If there is a range of reasonably estimated costs, the most likely amount will be recorded, or if no amount is most likely, the minimum of the range is used. Related expenditures are charged against the liability. Environmental remediation

liabilities have not been discounted for the time value of future expected payments. Environmental expenditures that have future economic benefit are capitalized.

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**INCOME TAXES** The Company accounts for income taxes using the asset and liability method. Under this method, income taxes are provided for amounts currently payable and for amounts deferred as tax assets and liabilities based on differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities. Deferred income taxes are measured using the enacted tax rates that are assumed will be in effect when the differences reverse. Petroleum revenue taxes are provided using the estimated effective tax rate over the life of applicable U.K. properties. The Company uses the deferral method to account for Canadian investment tax credits associated with the Hibernia and Terra Nova oil fields. As described in Notes B and H, the Company adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, as of January 1, 2007. This guidance permits recognition of income tax benefits only when they are more likely than not to be realized. The Company includes potential penalties and interest for uncertain income tax positions in income tax expense.

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

**DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES** The Company accounts for derivative instruments and hedging activity under SFAS No. 133, as amended by SFAS Nos. 138 and 149. The fair value of a derivative instrument is recognized as an asset or liability in the Company's Consolidated Balance Sheet. Upon entering into a derivative contract, the Company may designate the derivative as either a fair value hedge or a cash flow hedge, or decide that the contract is not a hedge, and thenceforth, recognize changes in the fair value of the contract in earnings. The Company documents the relationship between the derivative instrument designated as a hedge and the hedged items as well as its objective for risk management and strategy for use of the hedging instrument to manage the risk. Derivative instruments designated as fair value or cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. The Company assesses at inception and on an ongoing basis whether a derivative instrument used as a hedge is highly effective in offsetting changes in the fair value or cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting. Changes in the fair value of a qualifying fair value hedge are recorded in earnings along with the gain or loss on the hedged item. Changes in the fair value of a qualifying cash flow hedge are recorded in other comprehensive income until the hedged item is recognized in earnings. When the income effect of the underlying cash flow hedged item is recognized in the Statement of Income, the fair value of the associated cash flow hedge is reclassified from other comprehensive income into earnings. Ineffective portions of a cash flow hedge derivative's change in fair value are recognized currently in earnings. If a derivative instrument no longer qualifies as a cash flow hedge and the underlying forecasted transaction is no longer probable of occurring, hedge accounting is discontinued and the gain or loss recorded in other comprehensive income is recognized immediately in earnings.

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

**STOCK-BASED COMPENSATION** Under SFAS No. 123R, Share-Based Payment, the fair value of awarded stock options, restricted stock and restricted stock units is determined using a fair value based on a combination of management assumptions and the market value of the Company's common stock. The Company uses the Black-Scholes option pricing model for computing the fair value of stock options. The primary assumptions made by management include the expected life of the stock option award and the expected volatility of Murphy's common stock prices. The Company uses both historical data and current information to support its assumptions. Stock option expense is recognized on a straight-line basis over the respective vesting period of two or three years. The Company uses a Monte Carlo valuation model to determine the fair value of performance-based restricted stock and restricted stock units and expense is recognized over the three-year vesting period. The fair value of time-lapse restricted stock is determined based on the price of Company stock on the date of grant and is recognized over the vesting period. The Company estimates the number of stock options and performance-based restricted stock and restricted stock units that will not vest and adjusts its compensation expense accordingly. Differences between estimated and actual vested amounts are accounted for when known.

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

**Note B New Accounting Principles and Recent Accounting Pronouncements****New Accounting Principles Adopted**

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands



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disclosures about fair value measurements. This statement applies under other accounting pronouncements that require or permit fair value measurements, and where applicable simplifies and codifies related guidance within GAAP and does not require any new fair value

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measurements. The statement was originally effective for fiscal years beginning January 1, 2008. On February 12, 2008, the FASB issued FSP No. 157-2 that delayed for one year the effective date of SFAS No. 157 for most nonfinancial assets and nonfinancial liabilities. Provisions of the statement are to be applied prospectively except in limited situations. The Company adopted this statement as of January 1, 2008 and the adoption had no material impact on its consolidated financial statements. See further disclosures at Note N.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS No. 159). This pronouncement permits companies with eligible financial assets and financial liabilities to measure these items at fair value in the financial statements. This option to measure at fair value is both instrument specific and irrevocable. If the fair value option is elected, certain additional disclosures are required and financial statements for periods prior to the adoption may not be restated. The Company adopted this standard as of January 1, 2008, but the Company chose not to elect fair value measurement for any financial assets and financial liabilities, and therefore, the adoption of SFAS No. 159, had no impact on the Company's consolidated balance sheet or consolidated statement of income.

In June 2007, the FASB ratified the Emerging Issues Task Force's Issue No. 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards (EITF No. 06-11). This new guidance was effective for the Company beginning in January 2008 and required that income tax benefits received by the Company for dividends paid on share-based incentive awards be recorded in Capital in Excess of Par Value in Stockholders' Equity. Under certain circumstances, such tax benefits received on awards that do not vest could be reclassified to reduce income tax expense in the Consolidated Statements of Income. The effect of adopting EITF No. 06-11 in 2008 was not material to the Company's consolidated financial statements.

In September 2006, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of SFAS Nos. 87, 88, 106 and 132R (SFAS No. 158). This statement requires the Company to recognize in its consolidated balance sheet the overfunded or underfunded status of its defined benefit plans as an asset or liability and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This statement also requires that the Company measure the funded status of a plan as of December 31 rather than September 30 as previously permitted. The Company implemented this statement as to recognition of funded status as of December 31, 2006 and as to the year-end measurement date as of January 1, 2007. The adoption of the year-end measurement portion of this statement led to an adjustment to reduce Retained Earnings as of January 1, 2007 by \$4,301,000. Refer to Note J for further information.

In June 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48). This interpretation clarifies the criteria for recognizing income tax benefits under FASB Statement No. 109, Accounting for Income Taxes, and requires additional financial statement disclosures about uncertain tax positions. Effective January 1, 2007, the Company adopted FIN 48. Under FIN 48 the financial statement recognition of the benefit for a tax position is dependent upon the benefit being more likely than not to be sustainable upon audit by the applicable taxing authority. If this threshold is met, the tax benefit is then measured and recognized at the largest amount that is greater than 50 percent likely of being realized upon ultimate settlement. Upon adoption of FIN 48, the Company recognized a \$709,000 increase in its liability for unrecognized income tax benefits, which is included in Deferred Credits and Other Liabilities in the Consolidated Balance Sheet, and it recognized a similar decrease to Retained Earnings. Refer to Note H for further information.

**Recent Accounting Pronouncements**

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51. This statement is effective for the Company beginning January 1, 2009. Upon adoption, this statement will require noncontrolling interests to be reclassified as equity, and consolidated net income and comprehensive income shall include the respective results attributable to noncontrolling interests. It is to be applied prospectively and early adoption is not permitted. The Company does not expect this statement to have a significant effect on its consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations. This statement establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquired business. It also establishes how to recognize and measure goodwill acquired in the business combination or a gain from a bargain purchase, if applicable. This statement shall be applied prospectively by the Company to any business combination that occurs on or after January 1, 2009. Early application is prohibited. Assets and liabilities that arise from business combinations occurring prior to 2009 shall not be adjusted upon application of this statement. This statement will impact the recognition and measurement of assets and liabilities in business combinations that occur after 2008, and the Company is unable to predict at this time how the application of this statement will affect its financial statements in future periods.

In March 2008, the FASB issued SFAS No. 161, Disclosure about Derivative Instruments and Hedging Activities. This statement is effective for the Company beginning in January 2009, and it expands required disclosures regarding derivative instruments to include qualitative information about objectives and strategies for using derivatives, quantities disclosures about fair value amounts and gains and losses on derivative

instruments, and disclosures about credit-risk related contingent features in derivative agreements. The Company does not expect this statement to have a significant effect on its consolidated financial statements.

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In June 2008, the FASB issued FASB Staff Position on EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities (FSP EITF 03-6-1). This statement provides that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings per share (EPS) calculation under the two-class method. All prior-period EPS calculations must be adjusted retrospectively. This statement is effective for the Company in 2009. Although the Company is in the process of evaluating this statement, it does not expect the effect of adopting this statement in 2009 to have a significant impact on its prior-period EPS calculations.

In December 2008, the FASB issued Staff Position No. FAS 132(R)-1, Employers' Disclosures about Postretirement Benefit Plan Assets. This guidance will require additional disclosures about benefit plan assets, including how asset investment allocation decisions are made, the fair value of each major category of plan assets, and how fair value is determined for each major asset category. This guidance is effective for the Company at year-end 2009. Upon adoption, no comparative disclosures are required for earlier years presented. The Company does not expect the adoption of this standard to have a material impact on its consolidated financial statements in future periods.

In November 2008, the EITF published Issue No. 08-6, Equity Method Investment Accounting Considerations. This pronouncement gives guidance about how to initially measure contingent consideration for an equity method investment, how to recognize other-than-temporary impairments of an equity method investment, and how an equity method investor is to account for a share issuance by an investee. This guidance is effective for the Company at the beginning of its 2009 fiscal year. The guidance is to be applied prospectively and early adoption is not permitted. The Company is currently evaluating this guidance and is unable to predict at this time how it will impact its consolidated financial statements in future periods.

**Note C Milford Haven Refinery Acquisition**

On December 1, 2007, Murphy Oil's indirect wholly-owned subsidiary, Murco Petroleum Limited (Murco), acquired the remaining 70% interest in the Milford Haven, Wales, refinery in the U.K. Prior to the acquisition, Murco held an effective 30% interest in the 108,000 barrel per day refinery located in Pembrokeshire in southwest Wales. Post-acquisition, Murco owns 100% of the refinery. Murco paid cash consideration for the refinery complex, certain nearby land, the adjacent jetty, a pipeline connection to the Mainline Pipeline and spare parts. Murco also obtained the refinery workforce and primary operational systems, and purchased certain crude oil and products inventory at the time of acquisition. The total purchase price of \$348,292,000 included \$11,078,000 of transaction costs. Revenue and expenses associated with the 70% interest acquired have been included in the Company's consolidated financial statements beginning on December 1, 2007. No goodwill was recorded associated with this acquisition as the fair value of the assets acquired exceeded the purchase price paid by the Company.

**Note D Property, Plant and Equipment**

| <i>(Thousands of dollars)</i>           | December 31, 2008 |                        | December 31, 2007 |                        |
|---|-------------------|------------------------|-------------------|------------------------|
|   | Cost              | Net                    | Cost              | Net                    |
| Exploration and production <sup>1</sup> | \$ 8,485,391      | 5,791,945 <sub>2</sub> | 7,748,041         | 5,316,671 <sub>2</sub> |
| Refining                                | 1,649,679         | 881,436                | 1,665,807         | 922,443                |
| Marketing                               | 1,337,223         | 1,008,703              | 1,133,788         | 822,580                |
| Corporate and other                     | 79,818            | 45,634                 | 78,524            | 48,128                 |
|   | \$ 11,552,111     | 7,727,718              | 10,626,160        | 7,109,822              |

<sup>1</sup> Includes mineral rights as follows: \$ 536,884 374,646 461,974 377,307

<sup>2</sup> Includes \$13,983 in 2008 and \$13,730 in 2007 related to administrative assets and support equipment.

On December 1, 2006, the Company exchanged its interest in the Rimbey field in western Canada for an 80% interest in the common stock of Berkana Energy Corporation (Berkana). The Company recorded a \$9,909,000 pretax gain in 2006 associated with the Rimbey exchange. The transaction was accounted for as a reverse acquisition and the 20% interest of Berkana held by its other shareholders has been reported as Minority Interest in the Consolidated Balance Sheet. Murphy recorded 20% of Berkana's pretax results of operations as Minority Interest in the Consolidated Income Statement subsequent to the transaction. In January 2008, the Company sold its interest in Berkana Energy Corporation and recorded a pretax gain of \$41,950,000 (\$40,161,000 after-tax). In May 2008, the Company sold its interest in the Lloydminster area properties in Western Canada for a pretax gain of \$90,451,000 (\$67,236,000 after-tax).

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In 2007, the Company entered into an agreement with Walmart Stores, Inc. to purchase parcels of property leased from Walmart for its Murphy USA retail gasoline stations. A total of 835 sites have been purchased at a cost of \$304,200,000. In conjunction with purchasing these sites, the Company closed 55 stations in the U.S. and Canada in 2007. In the Consolidated Statement of Income for 2007, the Company recorded noncash impairment charges of \$40,708,000 primarily for writedown of the remaining book value and associated abandonment costs related to the North American retail gasoline station closures.

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The FASB issued FSP 19-1 to provide guidance on accounting for exploratory well costs and to amend SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies (SFAS No. 19). The guidance in FSP 19-1 applies to companies that use the successful efforts method of accounting as described in SFAS No. 19. This FSP clarifies that exploratory well costs should continue to be capitalized when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The guidance in this FSP was applied on a prospective basis beginning in April 2005 to existing and newly-capitalized exploratory well costs.

At December 31, 2008, 2007 and 2006, the Company had total capitalized drilling costs pending the determination of proved reserves of \$310,118,000, \$272,155,000 and \$315,445,000, respectively. The following table reflects the net changes in capitalized exploratory well costs during the three-year period ended December 31, 2008.

| <i>(Thousands of dollars)</i>  | 2008              | 2007     | 2006      |
|--|-------------------|----------|-----------|
| Beginning balance at January 1   | \$ 272,155        | 315,445  | 275,256   |
| Additions to capitalized exploratory well costs pending the determination of proved reserves | 44,832            | 6,856    | 158,234   |
| Reclassifications to proved properties based on the determination of proved reserves         | (6,869)           | (50,146) | (114,614) |
| Capitalized exploratory well costs charged to expense or sold                                |                   |          | (3,431)   |
| Ending balance at December 31  | <b>\$ 310,118</b> | 272,155  | 315,445   |

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

| <i>(Thousands of dollars)</i>    | 2008              |              |                 | 2007       |              |                 | 2006       |              |                 |
|----------------------------------|-------------------|--------------|-----------------|------------|--------------|-----------------|------------|--------------|-----------------|
|                                  | Amount            | No. of Wells | No. of Projects | Amount     | No. of Wells | No. of Projects | Amount     | No. of Wells | No. of Projects |
| Aging of capitalized well costs: |                   |              |                 |            |              |                 |            |              |                 |
| Zero to one year                 | \$ 48,424         | 4            | 4               | \$ 8,851   | 10           | 1               | \$ 122,399 | 25           | 5               |
| One to two years                 | 8,870             | 7            |                 | 101,120    | 19           | 4               | 107,212    | 10           | 2               |
| Two to three years               | 101,151           | 18           | 4               | 87,393     | 8            | 2               | 73,681     | 10           | 3               |
| Three years or more              | 151,673           | 14           | 4               | 74,791     | 8            | 2               | 12,153     | 1            | 1               |
|                                  | <b>\$ 310,118</b> | <b>43</b>    | <b>12</b>       | \$ 272,155 | 45           | 9               | \$ 315,445 | 46           | 11              |

Of the \$261,694,000 of exploratory well costs capitalized more than one year, \$169,283,000 is in Malaysia, \$60,251,000 is in the Republic of the Congo, \$27,633,000 is in the U.S., and \$4,527,000 is in Canada. In Malaysia either further appraisal or development drilling is planned and/or development studies/plans are in various stages of completion. In the Republic of the Congo a development program is underway for the offshore Azurite field with first oil production expected in 2009. In the U.S. further drilling is anticipated and development plans are being formulated, and in Canada a continuing drilling and development program is underway.

**Note E Financing Arrangements**

At December 31, 2008, the Company had a \$1,962,500,000 committed credit facility with a major banking consortium that matures in June 2012. Between June 2010 and June 2011, the capacity of the committed facility is reduced to \$1,905,000,000 and between June 2011 and June 2012 the maximum facility is \$1,827,500,000. At December 31, 2008, the Company had borrowed \$318,500,000 under this committed facility. Borrowings under this facility bear interest at prime or varying cost of fund options. Facility fees are due at varying rates on the commitment. At December 31, 2008 the Company had borrowed \$110,000,000 under uncommitted credit lines. If necessary, the Company could convert borrowings under these uncommitted lines to the committed long-term credit facility outstanding through 2012. The Company's shelf registration statement on file with the U.S. Securities and Exchange Commission that permitted the offer and sale of up to \$650,000,000 in debt and/or equity securities expired on December 31, 2008. The Company expects to file a new shelf registration in the second quarter of 2009.



**Table of Contents****Note F Long-term Debt**

| <i>(Thousands of dollars)</i>  | December 31         |                  |
|--|---------------------|------------------|
|  | 2008                | 2007             |
| Notes payable  |                     |                  |
| 6.375% notes, due 2012, net of unamortized discount of \$384 at December 31, 2008          | \$ 349,616          | 349,501          |
| 7.05% notes, due 2029, net of unamortized discount of \$1,894 at December 31, 2008         | 248,106             | 248,014          |
| Notes payable to banks, 0.925% to 3.20% at December 31, 2008                               | 428,500             | 915,500          |
| <b>Total notes payable</b>   | <b>1,026,222</b>    | <b>1,513,015</b> |
| Nonrecourse debt of a subsidiary   |                     |                  |
| Loans payable to Canadian government, interest free, payable in Canadian dollars, due 2009 | 2,572               | 8,349            |
| <b>Total debt including current maturities</b>   | <b>1,028,794</b>    | <b>1,521,364</b> |
| <b>Current maturities</b>  | <b>(2,572)</b>      | <b>(5,208)</b>   |
| <b>Total long-term debt</b>  | <b>\$ 1,026,222</b> | <b>1,516,156</b> |

Maturities for the four years after 2009 are: nil in 2010 and 2011, \$778,116,000 in 2012 and nil in 2013.

The interest-free loans from the Canadian government were used to finance expenditures for the Hibernia field. The outstanding balance is to be repaid in annual installments through 2009.

**Note G Asset Retirement Obligations**

The majority of the asset retirement obligations (ARO) recognized by the Company at December 31, 2008 and 2007 related to the estimated costs to dismantle and abandon its producing oil and gas properties and related equipment. A portion of the ARO relates to retail gasoline stations. The Company did not record an ARO for its refining and certain of its marketing assets because sufficient information is presently not available to estimate a range of potential settlement dates for the obligation. These assets are consistently being upgraded and are expected to be operational into the foreseeable future. In these cases, the obligation will be initially recognized in the period in which sufficient information exists to estimate the obligation.

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

| <i>(Thousands of dollars)</i>                    | 2008              | 2007           |
|--|-------------------|----------------|
| Balance at beginning of year                     | \$ 336,107        | 237,875        |
| Accretion expense                                | 24,484            | 16,244         |
| Liabilities incurred                             | 46,367            | 50,686         |
| Revision of previous estimates                   | 68,245            | 29,103         |
| Liabilities settled                              | (23,335)*         | (13,039)       |
| Changes due to translation of foreign currencies | (16,279)          | 15,238         |
| <b>Balance at end of year</b>                    | <b>\$ 435,589</b> | <b>336,107</b> |

\* Includes non-cash settlements related to sale of assets in Canada in 2008.

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





**Table of Contents****Note H Income Taxes**

The components of income before income taxes for each of the three years ended December 31, 2008 and income tax expense (benefit) attributable thereto were as follows.

| <i>(Thousands of dollars)</i> | 2008                | 2007      | 2006      |
|-------------------------------|---------------------|-----------|-----------|
| Income before income taxes    |                     |           |           |
| United States                 | \$ 476,882          | 415,124   | 339,426   |
| Foreign                       | 2,341,669           | 822,108   | 698,972   |
|                               | <b>\$ 2,818,551</b> | 1,237,232 | 1,038,398 |
| Income tax expense (benefit)  |                     |           |           |
| Federal Current               | \$ 134,759          | 82,033    | 120,591   |
| Deferred                      | 40,328              | 56,407    | (8,210)   |
|                               | <b>175,087</b>      | 138,440   | 112,381   |
| State                         | 16,714              | 15,969    | 2,245     |
| Foreign Current*              | 694,356             | 269,080   | 241,353   |
| Deferred*                     | 192,408             | 47,214    | 37,750    |
|                               | <b>886,764</b>      | 316,294   | 279,103   |
| Total                         | <b>\$ 1,078,565</b> | 470,703   | 393,729   |

\* Includes benefits of \$38,687 in 2007 and \$37,554 in 2006 for enacted reductions in federal and provincial tax rates in Canada. Tax expense in 2006 includes a charge of \$17,845 for an enacted increase in income tax rate for exploration and production operations in the U.K. Income tax benefits attributable to employee stock option transactions of \$22,495,000 in 2008, \$33,895,000 in 2007 and \$13,680,000 in 2006 were included in Capital in Excess of Par Value in the Consolidated Balance Sheets. Income tax charges of \$5,398,000 in 2006 relating to derivatives were included in Accumulated Other Comprehensive Income (AOCI).

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

| <i>(Thousands of dollars)</i>  | 2008                | 2007     | 2006     |
|--|---------------------|----------|----------|
| Income tax expense based on the U.S. statutory tax rate  | \$ 986,493          | 433,031  | 363,439  |
| Foreign income subject to foreign taxes at a rate different than the U.S. statutory rate       | 24,707              | 35,920   | 22,987   |
| State income taxes, net of federal benefit   | 10,864              | 10,380   | 1,459    |
| Changes in foreign tax rates   |                     | (38,687) | (19,709) |
| Increase in deferred tax asset valuation allowance related to foreign exploration expenditures | 31,535              | 12,533   | 20,147   |
| Other, net   | 24,966              | 17,526   | 5,406    |
| Total  | <b>\$ 1,078,565</b> | 470,703  | 393,729  |

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2008 and 2007 showing the tax effects of significant temporary differences follows.

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| <i>(Thousands of dollars)</i>                        | 2008                | 2007               |
|--|---------------------|--------------------|
| Deferred tax assets                                  |                     |                    |
| Property and leasehold costs                         | \$ 261,019          | 198,830            |
| Liabilities for dismantlements                       | 87,226              | 88,139             |
| Postretirement and other employee benefits           | 114,221             | 87,906             |
| Foreign tax credit carryforwards                     | 41,043              | 41,043             |
| Other deferred tax assets                            | 119,314             | 107,219            |
| <b>Total gross deferred tax assets</b>               | <b>622,823</b>      | <b>523,137</b>     |
| Less valuation allowance                             | (266,755)           | (214,120)          |
| <b>Net deferred tax assets</b>                       | <b>356,068</b>      | <b>309,017</b>     |
| Deferred tax liabilities                             |                     |                    |
| Property, plant and equipment                        | (430,056)           | (307,008)          |
| Accumulated depreciation, depletion and amortization | (604,267)           | (587,331)          |
| Deferred major repair costs                          | (18,142)            | (9,451)            |
| Foreign currency translation gains                   | (8,128)             | (150,005)          |
| Other deferred tax liabilities                       | (144,803)           | (98,748)           |
| <b>Total gross deferred tax liabilities</b>          | <b>(1,205,396)</b>  | <b>(1,152,543)</b> |
| <b>Net deferred tax liabilities</b>                  | <b>\$ (849,328)</b> | <b>(843,526)</b>   |

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In management's judgment, the net deferred tax assets in the preceding table will more likely than not be realized as reductions of future taxable income or by utilizing available tax planning strategies. The valuation allowance for deferred tax assets relates primarily to tax assets arising in foreign tax jurisdictions and foreign tax credit carryforwards. In the judgment of management at the present time, these tax assets are not likely to be realized. The foreign tax credit carryforwards expire in 2011, 2014 and 2015. The valuation allowance increased \$52,635,000 in 2008, with these changes primarily offsetting the change in certain deferred tax assets. Any subsequent reductions of the valuation allowance will be reported as reductions of tax expense assuming no offsetting change in the deferred tax asset.

The Company has not recognized a deferred tax liability for undistributed earnings of its Canadian and certain other foreign subsidiaries because such earnings are considered indefinitely invested in foreign countries. As of December 31, 2008, undistributed earnings of the Company's subsidiaries considered indefinitely invested were approximately \$3,177,000,000. The unrecognized deferred tax liability is dependent on many factors including withholding taxes under current tax treaties and foreign tax credits and is estimated to be \$224,100,000. The Company does not consider undistributed earnings from certain other international operations to be indefinitely invested; however, any estimated tax liabilities upon repatriation of earnings from these international operations are expected to be offset with foreign tax credits.

Tax returns are subject to audit by various taxing authorities. Although the Company believes that recorded liabilities for unsettled issues are adequate, additional gains or losses could occur in future years from resolution of outstanding unsettled matters.

In October 2004 the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004 (the Act) became law. The FASB issued FASB Staff Position (FSP) 109-1 in December 2004 to provide guidance on the application of SFAS No. 109, Accounting for Income Taxes, to the provision within the Act that provides, beginning in 2005, a tax deduction on qualified production activities. The tax deduction phased in at 3% in 2005 and is scheduled to reach 9% in 2010, however, the deduction will be limited to 6% for oil rated qualified production activities. FSP 109-1 concluded that the tax benefit for the deduction should be recognized as realized. This FSP was effective upon issuance and the Company applied it in computing U.S. income tax expense beginning in 2005. The Company recorded tax benefits of nil, \$4,725,000 and \$2,450,000 in 2008, 2007 and 2006, respectively, related to the Act.

**Uncertain Income Tax Positions**

Effective January 1, 2007, the Company adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48). This interpretation clarifies the criteria for recognizing income tax benefits under FASB Statement No. 109, Accounting for Income Taxes, and requires additional disclosures about uncertain tax positions. Under FIN 48 the financial statement recognition of the benefit for a tax position is dependent upon the benefit being more likely than not to be sustainable upon audit by the applicable taxing authority. If this threshold is met, the tax benefit is then measured and recognized at the largest amount that is greater than 50 percent likely of being realized upon ultimate settlement. Upon adoption of FIN 48, the Company recognized a \$709,000 increase in its liability for unrecognized income tax benefits, which is included in Deferred Credits and Other Liabilities in the Consolidated Balance Sheet, and it recognized a similar reduction of Retained Earnings. A reconciliation of the beginning and ending amount of the consolidated liability for unrecognized income tax benefits during the year ended December 31, 2008 follows.

| <i>(Thousands of dollars)</i>                          | 2008      | 2007   |
|--|-----------|--------|
| Balance at January 1                                   | \$ 25,598 | 16,436 |
| Additions for tax positions related to respective year | 6,558     | 9,101  |
| Settlements with tax authorities                       | (3,837)   |        |
| Settlements due to lapse of time                       | (7,502)   |        |
| Changes due to translation of foreign currencies       | (52)      | 61     |
| Balance at December 31                                 | \$ 20,765 | 25,598 |

All additions or reductions to the above liability, other than translation of foreign currencies, affect the Company's effective income tax rate in the respective period of change. The Company accounts for any applicable interest and penalties on uncertain tax positions as a component of income tax expense. The Company also had other recorded liabilities as of December 31, 2008 and 2007 for interest and penalties of \$2,640,000 and \$4,065,000, respectively, associated with uncertain tax positions. Income tax expense for the years ended December 31, 2008 and 2007 included a benefit for interest and penalties of \$1,185,000 and \$2,228,000, respectively, associated with uncertain tax positions.

During the next twelve months, the Company currently expects to add to the liability for uncertain taxes for 2009 events in amounts that approximate the liabilities included for 2008. Although existing liabilities could be reduced by settlement with taxing authorities or lapse due to

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statute of limitations, the Company believes that the changes in its unrecognized tax benefits due to these events will not have a material impact on the Consolidated Statement of Income during 2008. The Company's tax returns in multiple jurisdictions are subject to audit by taxing authorities. These audits often take years to complete and settle. As of December 31, 2008, the earliest years remaining open for audit and/or settlement in our major taxing jurisdictions are as follows: United States 2005; Canada 2003; United Kingdom 2005; Malaysia 2006; and Ecuador 2000.

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Statement of Financial Accounting Standards (SFAS) No. 123 (revised 2004), Share-Based Payment (SFAS No. 123R), requires that the cost resulting from all share-based payment transactions be recognized as an expense in the financial statements using a fair value-based measurement method over the periods that the awards vest.

At the annual meeting of shareholders on May 9, 2007, two new incentive compensation plans were approved and the Employee Stock Purchase Plan was amended. The 2007 Annual Incentive Plan (2007 Annual Plan) authorizes the Executive Compensation Committee (the Committee) to establish specific performance goals associated with annual cash awards that may be earned by officers, executives and other key employees. Cash awards under the 2007 Annual Plan are determined based on the Company's actual financial and operating results as measured against the performance goals established by the Committee. The 2007 Long-Term Incentive Plan (2007 Long-Term Plan) authorizes the Committee to make grants of the Company's Common Stock to employees. These grants may be in the form of stock options (nonqualified or incentive), stock appreciation rights (SAR), restricted stock, restricted stock units, performance units, performance shares, dividend equivalents and other stock-based incentives. The 2007 Long-Term Plan expires in 2017. A total of 6,700,000 shares are issuable during the life of the 2007 Long-Term Plan, with annual grants limited to 1% of Common shares outstanding; allowed shares not granted may be granted in future years. The Company also has a Stock Plan for Non-Employee Directors that permits the issuance of restricted stock, restricted stock units and stock options or a combination thereof to the Company's Directors. Upon approval by shareholders, the 2007 Long-Term Plan replaced the 1992 Stock Incentive Plan (1992 Plan). The 1992 Plan authorized the Committee to make annual grants of the Company's Common Stock to executives and other key employees in the form of stock options (nonqualified or incentive), SAR, and/or restricted stock. Annual grants could not exceed 1% of shares outstanding at the end of the preceding year.

The Company generally expects to issue new shares to satisfy future stock option exercises and vesting of restricted stock and restricted stock units.

Amounts recognized in the financial statements with respect to share-based plans are as follows.

| <i>(Thousands of dollars)</i>                                 | 2008      | 2007   | 2006   |
|---|-----------|--------|--------|
| Compensation charged against income before income tax benefit | \$ 25,656 | 22,241 | 18,814 |
| Related income tax benefit recognized in income               | 8,628     | 7,778  | 6,112  |

As of December 31, 2008, there was \$29,668,000 in compensation costs to be expensed over approximately the next two years related to unvested share-based compensation arrangements granted by the Company. Cash received from options exercised under all share-based payment arrangements for the years ended December 31, 2008, 2007 and 2006 was \$29,687,000, \$41,624,000 and \$24,864,000, respectively. Total income tax benefits realized from tax deductions related to stock option exercises under share-based payment arrangements were \$23,031,000, \$32,844,000 and \$14,134,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

**STOCK OPTIONS** The Committee fixes the option price of each option granted at no less than fair market value (FMV) on the date of the grant and fixes the option term at no more than 10 years from such date. Each option granted to date under the 2007 Long-Term Plan and the 1992 Plan has had a term of 7 to 10 years, has been nonqualified, and has had an option price equal to or higher than FMV at date of grant. Under the 2007 Long-Term Plan and the 1992 Plan, one-half of each grant is exercisable after two years and the remainder after three years. Under the 2003 Director Plan, one-third of each grant is exercisable after each of the first three years.

Under SFAS 123R, the fair value of each option award is estimated on the date of grant using the Black-Scholes pricing model that uses the assumptions noted in the following table. Expected volatility is based on historical volatility of the Company's stock and implied volatility on publicly traded at-the-money options on the Company's stock. The Company uses historical data to estimate option exercise patterns within the valuation model. The expected term of the options granted is derived from historical behavior and considers certain groups of employees exhibiting different behavior. The risk-free rate for periods within the expected term of the option is based on the U.S. Treasury yield curve in effect at the time of grant.

|                             | 2008     | 2007  | 2006     |
|-----------------------------|----------|-------|----------|
| Fair value per option grant | \$ 17.69 | 15.02 | \$ 17.53 |
| Assumptions                 |          |       |          |

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|                         |                  |           |           |
|-------------------------|------------------|-----------|-----------|
| Dividend yield          | <b>1.20%</b>     | 1.20%     | 0.90%     |
| Expected volatility     | <b>27.00%</b>    | 29.00%    | 30.00%    |
| Risk-free interest rate | <b>2.58%</b>     | 4.70%     | 4.42%     |
| Expected life           | <b>4.75 yrs.</b> | 4.75 yrs. | 4.75 yrs. |

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

|   | Number of<br>Shares | Average<br>Exercise<br>Price |
|---|---------------------|------------------------------|
| Outstanding at December 31, 2005        | 8,414,637           | \$ 21.92                     |
| Granted at FMV                          | 787,500             | 57.32                        |
| Exercised                               | (1,374,827)         | 17.18                        |
| Forfeited                               | (345,500)           | 45.73                        |
| Outstanding at December 31, 2006        | 7,481,810           | 25.41                        |
| Granted at FMV                          | 895,500             | 51.07                        |
| Exercised                               | (2,249,300)         | 17.96                        |
| Forfeited                               | (326,500)           | 35.74                        |
| Outstanding at December 31, 2007        | 5,801,510           | 31.65                        |
| Granted at FMV                          | <b>932,500</b>      | <b>72.75</b>                 |
| Exercised                               | <b>(1,255,450)</b>  | <b>20.56</b>                 |
| Forfeited                               | <b>(79,500)</b>     | <b>60.40</b>                 |
| <b>Outstanding at December 31, 2008</b> | <b>5,399,060</b>    | <b>\$ 40.90</b>              |
| Exercisable at December 31, 2006        | 5,544,656           | \$ 18.31                     |
| Exercisable at December 31, 2007        | 3,997,010           | 22.44                        |
| <b>Exercisable at December 31, 2008</b> | <b>3,375,810</b>    | <b>28.46</b>                 |

Additional information about stock options outstanding at December 31, 2008 is shown below.

| Range of Exercise  | Options Outstanding |                       |                                 | Options Exercisable |                       |                                 |
|--------------------|---------------------|-----------------------|---------------------------------|---------------------|-----------------------|---------------------------------|
|                    | No. of<br>Options   | Avg. Life<br>in Years | Aggregate<br>Intrinsic<br>Value | No. of<br>Options   | Avg. Life<br>in Years | Aggregate<br>Intrinsic<br>Value |
| Prices per Option  |                     |                       |                                 |                     |                       |                                 |
| \$ 8.92 to \$19.43 | 1,150,800           | 2.2                   | \$ 32,012,000                   | 1,150,800           | 2.2                   | \$ 32,012,000                   |
| \$21.17 to \$38.18 | 1,370,010           | 3.2                   | 25,808,000                      | 1,370,010           | 3.2                   | 25,808,000                      |
| \$45.23 to \$72.75 | 2,878,250           | 4.8                   |                                 | 855,000             | 3.4                   |                                 |
|                    | 5,399,060           | 3.9                   | \$ 57,820,000                   | 3,375,810           | 2.9                   | \$ 57,820,000                   |

The total intrinsic value of options exercised during 2008, 2007 and 2006 was \$71,405,000, \$98,863,000 and \$48,701,000, respectively. Intrinsic value is the excess of the market price of stock at date of exercise over the exercise price received by the Company upon exercise. Aggregate intrinsic value is nil when the exercise price of the stock option exceeds the market price of the Company's Common stock.

SAR SAR may be granted in conjunction with or independent of stock options; if granted, the Committee would determine when SAR may be exercised and the price. No SAR have been granted.

**PERFORMANCE-BASED RESTRICTED STOCK AND RESTRICTED STOCK UNITS** Shares of restricted stock were granted under the 1992 Plan in certain years and restricted stock units were granted in 2008 and 2007 under the 2007 Long-Term Plan. Each grant will vest if the Company achieves specific objectives based on market conditions at the end of the designated performance period. Additional shares may be awarded if objectives are exceeded, but some or all shares may be forfeited if objectives are not met. The market conditions generally include a measure of the Company's total shareholder return over the performance period compared to an industry peer group of companies. During the performance period, a grantee receives dividends on restricted stock and may vote these shares, but shares are subject to transfer restrictions and are subject to forfeiture if a grantee terminates. No dividends are paid or voting rights exist on awards of restricted stock units. Changes in



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performance-based restricted stock and restricted stock units outstanding for each of the last three years are presented in the following table.

| <i>(Number of shares)</i>    | <b>2008</b>        | <b>2007</b> | <b>2006</b> |
|------------------------------|--------------------|-------------|-------------|
| Balance at beginning of year | <b>798,497</b>     | 680,292     | 478,445     |
| Granted                      | <b>328,000</b>     | 299,000     | 265,750     |
| Forfeited                    | <b>(319,675)</b>   | (180,795)   | (63,903)    |
| <br>Balance at end of year   | <br><b>806,822</b> | <br>798,497 | <br>680,292 |

The fair value of the performance-based awards granted in 2008, 2007 and 2006 was estimated on the date of grant using a Monte Carlo valuation model. If performance goals are not met, shares will not be awarded, but recognized compensation cost associated with the stock award would not be reversed.

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Expected volatility was based on daily historical volatility of the Company's stock price compared to a peer group average over a three year period. The risk-free interest rate is based on the yield curve of three year U.S. Treasury bonds and the stock beta was calculated using three years of historical averages of daily stock data for Murphy and the peer group. The assumptions used in the valuation of the performance awards granted in 2008, 2007 and 2006 are presented in the following table.

|                                    | 2008      |          | 2007      |          | 2006      |
|------------------------------------|-----------|----------|-----------|----------|-----------|
| Fair value per share at grant date | \$ 52.70  | \$ 62.53 | \$ 45.05  | \$ 48.23 | \$ 37.33  |
| Assumptions                        |           |          |           |          |           |
| Expected volatility                | 29.00%    |          | 27.10%    |          | 26.30%    |
| Risk-free interest rate            | 2.08%     |          | 4.64%     |          | 4.49%     |
| Stock beta                         | 0.885     |          | 0.912     |          | 0.955     |
| Expected life                      | 3.00 yrs. |          | 3.00 yrs. |          | 3.00 yrs. |

**TIME-LAPSE RESTRICTED STOCK** Shares of restricted stock were granted to the Company's Directors under the 2003 Director Plan and vest on the third anniversary of the date of grant. In addition, the Committee awarded 60,000 time-lapse restricted stock units to an officer during 2008. The fair value of these awards was estimated based on the fair market value of the Company's stock on the date of grant, which was \$72.75 per share in 2008, \$51.07 per share in 2007, and \$57.32 per share in 2006. Changes in time-lapse restricted stock and restricted stock units outstanding for each of the periods are presented in the following table.

| <i>(Number of shares)</i>    | 2008     | 2007     | 2006   |
|------------------------------|----------|----------|--------|
| Balance at beginning of year | 68,289   | 56,142   | 35,574 |
| Granted                      | 84,930   | 32,750   | 20,568 |
| Expired                      | (20,400) | (15,706) |        |
| Forfeited                    |          | (4,897)  |        |
| Balance at end of year       | 132,819  | 68,289   | 56,142 |

**EMPLOYEE STOCK PURCHASE PLAN (ESPP)** The Company has an ESPP under which the Company's Common Stock can be purchased by eligible U.S. and Canadian employees. Each quarter, an eligible employee may elect to withhold up to 10% of his or her salary to purchase shares of the Company's stock at the end of the quarter at a price equal to 90% of the fair value of the stock as of the first day of the quarter. The ESPP was amended in 2007 to increase the authorized number of shares and increase its term. The ESPP will now terminate on the earlier of the date that employees have purchased all 980,000 authorized shares or June 30, 2017. Employee stock purchases under the ESPP were 20,715 shares at an average price of \$73.94 per share in 2008, 30,011 shares at \$52.68 per share in 2007, and 28,280 shares at \$45.88 per share in 2006. At December 31, 2008, 450,479 shares remained available for sale under the ESPP. Compensation costs related to the ESPP are estimated based on the value of the 10% discount and the fair value of the option that provides for the refund of participant withholdings, and such expenses were \$401,000 in 2008, \$253,000 in 2007 and \$256,000 in 2006. The fair value per share issued under the ESPP was approximately \$13.03, \$8.32, and \$7.57 for the years ended December 31, 2008, 2007 and 2006, respectively.

**SAVINGS-RELATED SHARE OPTION PLAN (SOP)** One of the Company's U.K. subsidiaries provides a plan that allows shares of the Company's Common stock to be purchased by eligible employees using payroll withholdings. An eligible employee may elect to withhold from £5 to £250 per month to purchase shares of Company stock at a price equal to 90% of the fair value of the stock as of the date of grant. The SOP plan has a term of three years and employee withholdings are fixed over the life of the plan. At the end of the term of the SOP plan an employee receives interest on withholdings and has six months to either use all or part of the withholdings plus credited interest to purchase shares of Company stock or receive a repayment of withholdings plus credited interest. Compensation costs related to the SOP plan are estimated based on the value of the 10% discount and the fair value of the option that allows the employee to receive a repayment of withholdings plus credited interest. The fair value per share of the SOP plans with holding periods ending in May 2007, December 2009 and August 2010 were determined to be \$11.64, \$19.57 and \$19.90, respectively.

**CASH AWARDS** The Committee also administers the Company's incentive compensation plans, which provide for annual or periodic cash awards to officers, directors and key employees. These cash awards are generally determinable based on the Company achieving specific financial and/or operational objectives. Compensation expense of \$23,793,000, \$23,716,000 and \$14,862,000 was recorded in 2008, 2007 and 2006, respectively, for these plans.

**Note J Employee and Retiree Benefit Plans**

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

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In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* an amendment of SFAS Nos. 87, 88, 106 and 132R (SFAS No. 158). This statement requires the Company to recognize in its consolidated balance sheet the overfunded or underfunded status of its defined benefit plans as an asset or liability and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This statement also requires that the Company measure the funded status of all plans as of December 31 rather than September 30 as previously permitted.

The Company adopted the requirement to use a December 31 measurement date for defined benefit plan measurement beginning in 2007. The transition from a measurement date as of September 30 to December 31 required the Company to reduce its consolidated Retained Earnings as of January 1, 2007 by \$4,301,000 to recognize the one-time after-tax effect of an additional three months of net periodic benefit expense for its retirement and postretirement benefit plans.

The tables that follow provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets for the years ended December 31, 2008 and 2007 and a statement of the funded status as of December 31, 2008 and 2007.

| <i>(Thousands of dollars)</i>   | Pension Benefits |           | Other Postretirement Benefits |          |
|---|------------------|-----------|-------------------------------|----------|
|   | 2008             | 2007      | 2008                          | 2007     |
| <b>Change in benefit obligation</b>   |                  |           |                               |          |
| Obligation at January 1   | \$ 446,386       | 429,398   | 80,685                        | 72,567   |
| Adjustment due to adoption of SFAS No. 158  |                  | 2,606     |                               | 1,685    |
| Service cost  | 17,928           | 11,424    | 2,708                         | 2,283    |
| Interest cost   | 27,667           | 24,492    | 5,087                         | 4,354    |
| Plan amendments   | 2,582            |           |                               |          |
| Participant contributions   | 36               | 51        | 846                           | 941      |
| Actuarial (gain) loss   | (1,035)          | (5,456)   | 2,802                         | 3,257    |
| Medicare Part D subsidy   |                  |           | 195                           | 387      |
| Exchange rate changes   | (29,756)         | 5,313     |                               |          |
| Benefits paid   | (22,111)         | (21,442)  | (5,005)                       | (4,789)  |
| Other   |                  |           |                               |          |
| Obligation at December 31   | 441,697          | 446,386   | 87,318                        | 80,685   |
| <b>Change in plan assets</b>  |                  |           |                               |          |
| Fair value of plan assets at January 1  | 339,259          | 313,214   |                               |          |
| Adjustment due to adoption of SFAS No. 158  |                  | 3,736     |                               |          |
| Actual return on plan assets  | (63,312)         | 25,107    |                               |          |
| Employer contributions  | 50,639           | 12,156    | 3,964                         | 3,461    |
| Participant contributions   | 36               | 51        | 846                           | 941      |
| Medicare Part D subsidy   |                  |           | 195                           | 387      |
| Exchange rate changes   | (26,090)         | 6,785     |                               |          |
| Benefits paid   | (22,111)         | (21,442)  | (5,005)                       | (4,789)  |
| Other   | (338)            | (348)     |                               |          |
| Fair value of plan assets at December 31  | 278,083          | 339,259   |                               |          |
| <b>Funded status and amounts recognized in the Consolidated Balance Sheets at December 31</b> |                  |           |                               |          |
| Deferred charges and other assets   | 11,069           | 17,649    |                               |          |
| Other accrued liabilities   | (13,244)         | (33,251)  |                               |          |
| Deferred credits and other liabilities  | (161,439)        | (91,525)  | (87,318)                      | (80,685) |
| Funded status and net plan liability recognized at December 31                                | \$ (163,614)     | (107,127) | (87,318)                      | (80,685) |



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At December 31, 2008, amounts included in accumulated other comprehensive income (AOCI), before reduction for associated deferred income taxes, which have not been recognized in net periodic benefit expense are shown in the following table.

| <i>(Thousands of dollars)</i> | Pension<br>Benefits<br>2008 | Other<br>Postretirement<br>Benefits<br>2008 |
|-------------------------------|-----------------------------|---|
| Net loss                      | \$ (169,101)                | (32,528)                                    |
| Prior service (cost) credit   | (9,686)                     | 2,511                                       |
| Transitional asset            | 2,996                       |   |
|                               | \$(175,791)                 | (30,017)                                    |

Amounts included in AOCI at December 31, 2008 that are expected to be amortized into net periodic benefit expense during 2009 are shown in the following table.

| <i>(Thousands of dollars)</i> | Pension<br>Benefits<br>2008 | Other<br>Postretirement<br>Benefits<br>2008 |
|-------------------------------|-----------------------------|---|
| Net loss                      | \$ (11,239)                 | (1,673)                                     |
| Prior service (cost) credit   | (1,793)                     | 264   |
| Transitional costs            | (499)                       |   |
|                               | \$ (13,531)                 | (1,409)                                     |

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

| <i>(Thousands of dollars)</i>   | Projected Benefit<br>Obligations |         | Accumulated<br>Benefit<br>Obligations |         | Fair Value of Plan<br>Assets |         |
|---|----------------------------------|---------|---------------------------------------|---------|------------------------------|---------|
|   | 2008                             | 2007    | 2008                                  | 2007    | 2008                         | 2007    |
| Funded qualified plans where accumulated benefit obligation exceeds fair value of plan assets                     | \$ 370,793                       | 377,503 | 317,418                               | 330,511 | 254,819                      | 302,970 |
| Unfunded nonqualified and directors' plans where accumulated benefit obligation exceeds fair value of plan assets | 58,709                           | 50,244  | 40,667                                | 39,970  |                              |         |
| Unfunded other postretirement plans   | 87,318                           | 80,685  | 87,318                                | 80,685  |                              |         |

The table that follows provides the components of net periodic benefit expense for each of the three years ended December 31, 2008.

| <i>(Thousands of dollars)</i>      | Pension Benefits |          |          | Other<br>Postretirement Benefits |       |       |
|------------------------------------|------------------|----------|----------|----------------------------------|-------|-------|
|                                    | 2008             | 2007     | 2006     | 2008                             | 2007  | 2006  |
| Service cost                       | \$ 17,928        | 11,424   | 10,264   | 2,708                            | 2,283 | 2,128 |
| Interest cost                      | 27,667           | 24,492   | 21,670   | 5,087                            | 4,354 | 3,923 |
| Expected return on plan assets     | (23,131)         | (21,644) | (20,315) |                                  |       |       |
| Amortization of prior service cost | 1,693            | 1,422    | 1,929    | (264)                            | (264) | (277) |

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|                                      |           |        |        |       |       |       |
|--------------------------------------|-----------|--------|--------|-------|-------|-------|
| Amortization of transitional asset   | (499)     | (494)  | (490)  |       |       |       |
| Recognized actuarial loss            | 5,119     | 5,746  | 6,416  | 1,639 | 1,589 | 1,637 |
|                                      | 28,777    | 20,946 | 19,474 | 9,170 | 7,962 | 7,411 |
| Special termination benefits expense |           |        | 4,748  |       |       |       |
| Curtailment expense (benefit)        |           |        | 594    |       |       | (152) |
| Net periodic benefit expense         | \$ 28,777 | 20,946 | 24,816 | 9,170 | 7,962 | 7,259 |

Termination and curtailment expense in 2006 primarily related to the reorganization of the Company's U.S. exploration and production operation.

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

|  | Pension Benefits |         | Other Postretirement Benefits |      |
|--|------------------|---------|-------------------------------|------|
|  | 2008             | 2007    | 2008                          | 2007 |
| <i>(Thousands of dollars)</i>            |                  |         |                               |      |
| Benefit obligation at December 31        | \$ 84,696        | 117,224 |                               |      |
| Fair value of plan assets at December 31 | 78,025           | 106,057 |                               |      |
| Net plan liability (asset) recognized    | (6,671)          | 11,165  |                               |      |
| Net periodic benefit expense             | 8,231            | 3,342   |                               |      |

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2008 and 2007 and net periodic benefit expense for the years 2008 and 2007.

|                                | Benefit Obligations |             |                         |             | Net Periodic Benefit Expense |       |                         |       |
|--------------------------------|---------------------|-------------|-------------------------|-------------|------------------------------|-------|-------------------------|-------|
|                                | Pension Benefits    |             | Postretirement Benefits |             | Pension Benefits             |       | Postretirement Benefits |       |
|                                | December 31         | December 31 | December 31             | December 31 | Year                         | Year  | Year                    | Year  |
|                                | 2008                | 2007        | 2008                    | 2007        | 2008                         | 2007  | 2008                    | 2007  |
| Discount rate                  | 6.40%               | 6.25%       | 6.50%                   | 6.50%       | 6.31%                        | 5.76% | 6.50%                   | 6.00% |
| Expected return on plan assets | 6.58%               | 6.93%       |                         |             | 6.58%                        | 6.89% |                         |       |
| Rate of compensation increase  | 4.41%               | 4.42%       |                         |             | 4.41%                        | 4.40% |                         |       |

The discount rates used for purposes of determining the plan obligations and expense are based on the universe of

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

The weighted average asset allocation for the Company's benefit plans at the annual measurement dates of December 31, 2008 and 2007 are presented in the following table.

|                   | December 31, |        |
|-------------------|--------------|--------|
|                   | 2008         | 2007   |
| Equity securities | 52.2%        | 57.3%  |
| Debt securities   | 47.1         | 41.4   |
| Cash              | .7           | 1.3    |
|                   | 100.0%       | 100.0% |

The Company has directed the asset investment advisors of its benefit plans to maintain a portfolio nearly balanced between equity and debt securities. The investment advisors may vary the asset mix within the range of 40% to 70% for equity securities and 30% to 60% for debt securities. The Company believes that over time a balanced to slightly heavier weighting of the portfolio in equity securities compared to debt securities represents the most appropriate long-term mix for future investment return on domestic plans' assets. Investment advisors are not permitted to invest benefit plan assets in Murphy Oil's Common Stock.

The Company's weighted average expected return on plan assets was 6.58% in 2008 and the return was determined based on an assessment of actual long-term historical returns and expected future returns for a portfolio with investment characteristics similar to that maintained by the



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plans. The 6.58% expected return was based on an expected average future equity securities return of 8.47% and a debt securities return of 5.24% and is net of average expected investment expenses of 0.52%. Over the last 10 years, the return on funded retirement plan assets has averaged 5.43%.

During 2008, the Company made contributions of \$30,010,000 to its domestic defined benefit pension plans, \$20,629,000 to its foreign defined benefit pension plan and \$3,964,000 to its domestic postretirement benefits plan. The Company currently expects during 2009 to make contributions of \$43,153,000 to its domestic defined benefit pension plans, \$7,077,000 to its foreign defined benefit pension plans and \$4,890,000 to its domestic postretirement benefits plan. The 2009 retirement plan contribution includes a currently anticipated voluntary contribution of \$30,000,000.

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

| <i>(Thousands of dollars)</i> | <b>Pension<br/>Benefits</b> | <b>Other<br/>Postretirement<br/>Benefits</b> |
|-------------------------------|-----------------------------|--|
| 2009                          | \$ 22,681                   | 5,413  |
| 2010                          | 23,423                      | 5,891  |
| 2011                          | 24,061                      | 6,267  |
| 2012                          | 24,906                      | 6,653  |
| 2013                          | 26,156                      | 7,037  |
| 2014-2018                     | 149,858                     | 40,484                                       |

For purposes of measuring postretirement benefit obligations at December 31, 2008, the future annual rates of increase in the cost of health care were assumed to be 9.0% for 2009 decreasing each year to an ultimate rate of 5.0% in 2018 and thereafter.

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

| <i>(Thousands of dollars)</i>  | <b>1% Increase</b> | <b>1% Decrease</b> |
|--|--------------------|--------------------|
| Effect on total service and interest cost components of net periodic postretirement benefit expense for the year ended December 31, 2008 | \$ 1,314           | (1,046)            |
| Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 2008                            | 11,887             | (9,768)            |

During 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) became law. Among other provisions, the Act changed prescription drug coverage under Medicare beginning in 2006. Generally, companies that provide qualifying prescription drug coverage that is deemed actuarially equivalent to Medicare coverage for retirees aged 65 and above will be eligible to receive a federal subsidy equal to 28% of drug costs between \$250 and \$5,000 per annum of each covered individual that does not elect to receive coverage under the new Medicare Part D. The Company currently provides prescription drug coverage to qualifying retirees under its retiree medical plan. As a result of provisions in the Act, the Company's postretirement benefit expense was reduced by \$2,457,000, \$1,507,000 and \$1,422,000 during 2008, 2007 and 2006, respectively.

**THRIFT PLANS** Most full-time employees of the Company may participate in thrift or savings plans by allotting up to a specified percentage of their base pay. The Company matches contributions at a stated percentage of each employee's allotment based on years of participation in the plans. A U.K. savings plan allows eligible employees to allot a portion of their base pay to purchase Company Common Stock at market value. Such employee allotments are matched by the Company. Common Stock issued from the Company's treasury under this U.K. savings plan was 7,780 shares in 2007 and 16,571 shares in 2005. Amounts charged to expense of these U.S. and U.K. plans were \$6,215,000 in 2008, \$9,252,000 in 2007 and \$2,957,000 in 2006.

**Note K Financial Instruments and Risk Management**

**DERIVATIVE INSTRUMENTS** Murphy makes limited use of derivative instruments to manage certain risks related to commodity prices, interest rates and foreign currency exchange rates. The use of derivative instruments for risk management is covered by operating policies and is closely monitored by the Company's senior management. The Company does not hold any derivatives for speculative purposes and it does not use derivatives with leveraged or complex features. Derivative instruments are traded primarily with creditworthy major financial institutions or over national exchanges such as the New York Mercantile Exchange (NYMEX). To qualify for hedge accounting, the changes in the market value of a derivative instrument must historically have been, and would be expected to continue to be, highly effective at offsetting changes in the prices of the hedged item. To the extent that the change in fair value of a derivative instrument has less than perfect correlation with the change in the fair value of the hedged item, a portion of the change in fair value of the derivative instrument is considered ineffective and would normally be recorded in earnings during the affected period.

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*Crude Oil Purchase Price Risks* The Company purchases crude oil as feedstock at its U.S. and U.K. refineries and is therefore subject to commodity price risk. Short-term derivative instruments were outstanding at December 31, 2008 to manage the 2009 purchase price of 1,063,000 barrels of crude oil at the Company's Superior, Wisconsin refinery. At December 31, 2007 essentially offsetting short-term derivative instruments were outstanding to manage the 2008 purchase price of 403,000 barrels of crude oil at the Company's Meraux, Louisiana refinery. The total impact of marking these contracts to market at the respective year-end was pretax charges of \$1,378,000 in 2008 and \$40,000 in 2007.

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**Natural Gas Fuel Price Risks** The Company purchases natural gas as fuel at its Meraux, Louisiana and Superior, Wisconsin refineries, and as such, is subject to commodity price risk related to the purchase price of this gas. Murphy hedged the cash flow risk associated with the cost of a portion of the natural gas it purchased during 2006 by entering into financial contracts known as natural gas swaps with a notional volume during 2006 of 720,000 MMBTU (1 MMBTU = 1 million British Thermal Units). Under the natural gas swaps, the Company paid a fixed rate averaging \$3.35 per MMBTU and received a floating rate in each month of settlement based on the average NYMEX price for the final three trading days of the month. Murphy has a risk management control system to monitor natural gas price risk attributable both to forecasted natural gas requirements and to Murphy's natural gas swaps. The control system involves using analytical techniques, including various correlations of natural gas purchase prices to future prices, to estimate the impact of changes in natural gas fuel prices on Murphy's cash flows. The fair value of the effective portions of the natural gas swaps and changes thereto was deferred in AOCI and was subsequently reclassified into Operating Expenses in the income statements in the periods in which the hedged natural gas fuel purchases occurred. For the year ended December 31, 2006, expense from cash flow hedging ineffectiveness for these contracts was \$28,000. During the year ended December 31, 2006, the Company received approximately \$2,791,000 in cash proceeds from maturing swap agreements.

**Crude Oil Sales Price Risks** The sales price of crude oil produced by the Company is subject to commodity price risk. Murphy hedged the cash flow risk associated with the sales price for a portion of its 2006 Canadian heavy oil production by entering into forward sale contracts covering a notional volume of approximately 4,000 barrels per day. The Company paid the average of the posted price at the Hardisty terminal in Canada for each month and received a fixed price of \$25.23 per barrel. Murphy has a risk management control system to monitor crude oil price risk attributable both to forecasted crude oil sales prices and to Murphy's hedging instruments. The control system involves using analytical techniques, including various correlations of crude oil sales prices to futures prices, to estimate the impact of changes in crude oil prices on Murphy's cash flows from the sale of crude oil. The fair value of the effective portions of the crude oil sales price hedges and changes thereto was deferred in AOCI and was subsequently reclassified into Sales and Other Operating Revenues in the income statement in the periods in which the hedged crude oil sales occurred. During 2006, earnings were increased by \$160,000 for cash flow hedging ineffectiveness on crude oil sales price hedges, and the Company paid approximately \$29,373,000 for settlement of maturing crude oil sales swaps.

**CREDIT RISKS** The Company's primary credit risks are associated with trade accounts receivable, cash equivalents and derivative instruments. Trade receivables arise mainly from sales of crude oil, natural gas and petroleum products to a large number of customers in the United States, Canada and the United Kingdom. The Company also has credit risk for sales of crude oil to various customers in Malaysia and Ecuador. The credit history and financial condition of potential customers are reviewed before credit is extended, security is obtained when deemed appropriate based on a potential customer's financial condition, and routine follow-up evaluations are made. The combination of these evaluations and the large number of customers tends to limit the risk of credit concentration to an acceptable level. Cash equivalents are placed with several major financial institutions, which limits the Company's exposure to credit risk. The Company controls credit risk on derivatives through credit approvals and monitoring procedures and believes that such risks are minimal because counterparties to the majority of transactions are major financial institutions.

**Note L Earnings per Share**

The following table reconciles the weighted-average shares outstanding for computation of basic and diluted income per Common share for each of the three years ended December 31, 2008. No difference existed between net income used in computing basic and diluted income per Common share for these years.

| <i>(Weighted-average shares outstanding)</i> | 2008               | 2007        | 2006        |
|--|--------------------|-------------|-------------|
| Basic method                                 | <b>189,608,846</b> | 188,027,557 | 186,105,086 |
| Dilutive stock options                       | <b>2,524,826</b>   | 3,113,180   | 3,053,325   |
| Diluted method                               | <b>192,133,672</b> | 191,140,737 | 189,158,411 |

Certain outstanding options to purchase shares of Common stock at year-end 2008 and 2006 were not included in the computation of diluted earnings per share because the incremental shares from assumed conversion were antidilutive. These included options for 924,000 shares at a weighted average of \$72.75 at year-end 2008, and 706,000 shares at a weighted average price of \$57.32 at year-end 2006. There were no antidilutive options for the 2007 period.

**Note M Other Financial Information**

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**INVENTORIES** Inventories accounted for under the LIFO method totaled \$342,984,000 and \$361,651,000 at December 31, 2008 and 2007, respectively, and these amounts were \$202,477,000 and \$709,743,000 less than such inventories would have been valued using the FIFO method.

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ACCUMULATED OTHER COMPREHENSIVE INCOME At December 31, 2008 and 2007, the components of Accumulated Other Comprehensive Income were as follows.

| <i>(Thousands of dollars)</i>  | 2008        | 2007     |
|--|-------------|----------|
| Foreign currency translation gains, net of tax                       | \$ 45,517   | 428,538  |
| Retirement and postretirement plan liability adjustments, net of tax | (133,214)   | (76,773) |
| Balance at end of year   | \$ (87,697) | 351,765  |

At December 31, 2008, components of the net foreign currency translation gain of \$45,517,000 were gains of \$10,373,000 for Canadian dollars, \$32,139,000 for pounds sterling and \$3,005,000 for other currencies. Foreign currency translation gains shown in the table are net of income taxes of \$8,128,000 and \$150,005,000 at year-end 2008 and 2007, respectively. Net losses from foreign currency transactions included in the Consolidated Statements of Income were \$105,620,000 in 2008, \$20,637,000 in 2007 and \$8,000,000 in 2006.

The effect of SFAS Nos. 133/138, Accounting for Derivative Instruments and Hedging Activities, increased AOCI for the year ended December 31, 2006 by \$13,459,000, net of \$5,398,000 in income taxes, and income increased by \$132,000 for the same period.

CASH FLOW DISCLOSURES Cash income taxes paid were \$380,602,000, \$297,274,000 and \$466,087,000 in 2008, 2007 and 2006, respectively. Interest paid, net of amounts capitalized, was \$43,715,000, \$22,274,000 and \$7,270,000 in 2008, 2007 and 2006, respectively.

Noncash operating working capital (increased) decreased during each of the three years ended December 31, 2008 as follows.

| <i>(Thousands of dollars)</i>   | 2008       | 2007      | 2006      |
|---|------------|-----------|-----------|
| Accounts receivable   | \$ 386,605 | (445,677) | (128,004) |
| Inventories   | 22,474     | (107,945) | (96,122)  |
| Prepaid expenses  | (12,959)   | 57,089    | (103,435) |
| Deferred income tax assets  | 56,451     | (65,391)  | 19,403    |
| Accounts payable and accrued liabilities  | (626,948)  | 661,599   | 95,069    |
| Current income tax liabilities  | 342,589    | 45,779    | (42,881)  |
| Net (increase) decrease in noncash operating working capital, excluding acquisition of the Milford Haven refinery in 2007 | \$ 168,212 | 145,454   | (255,970) |

**Note N Assets and Liabilities Measured at Fair Value**

As described in Note B, the Company adopted SFAS No. 157, Fair Value Measurements (SFAS No. 157), on January 1, 2008, other than for nonrecurring nonfinancial assets and liabilities, which will be effective for the Company on January 1, 2009. SFAS No. 157 establishes a fair value hierarchy based on the quality of inputs used to measure fair value, with Level 1 being the highest quality and Level 3 being the lowest quality. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs which reflect assumptions about pricing by market participants.

The fair value measurements for the Company's financial liabilities accounted for at fair value on a recurring basis at December 31, 2008 are presented in the following table.

| December 31, 2008 | Fair Value Measurements at Reporting Date Using |  |                                       |
|-------------------|---|--|---------------------------------------|
|                   | Quoted Prices<br>in Active<br>Markets           | Significant Other<br>Observable<br>Inputs<br>(Level 2) | Significant<br>Unobservable<br>Inputs |

**for Identical  
Assets (Liabilities)  
(Level 1)**

(Level 3)

*(Thousands of dollars)*Liabilities

|                                    |            |         |         |
|------------------------------------|------------|---------|---------|
| Nonqualified employee savings plan | \$ (6,804) | (6,804) |         |
| Commodity derivatives              | (1,378)    |         | (1,378) |
| Total liabilities at fair value    | \$ (8,182) | (6,804) | (1,378) |

The nonqualified employee savings plan is an unfunded savings plan through which the owners seek a return via phantom investments in equity securities and/or mutual funds. Fair value of this liability was based on quoted prices for these equity securities and mutual funds. The fair value of commodity derivatives was determined based on market quotes for WTI crude contracts at the balance sheet date. The income effect of the changes in the fair value of nonqualified employee savings plan is recorded in Selling and General Expense in the Consolidated Statement of Income, while the change in fair value of commodity derivatives is recorded in Crude Oil and Product Purchases. The carrying value of the Company's Cash and Cash Equivalents, Accounts Receivable and Accounts Payable approximates fair value.

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The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2008 and 2007. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties. The table excludes cash and cash equivalents, trade accounts receivable, short-term notes payable, trade accounts payable and accrued expenses, all of which had fair values approximating carrying amounts. The carrying value of Canadian government securities is determined based on cost plus earned interest. The fair value of current and long-term debt was estimated based on rates offered to the Company at that time for debt of the same maturities. The Company has off-balance sheet exposures relating to certain financial guarantees and letters of credit. The fair value of these, which represents fees associated with obtaining the instruments, was nominal.

|  | 2008            |            | At December 31, 2007 |             |
|--|-----------------|------------|----------------------|-------------|
|  | Carrying Amount | Fair Value | Carrying Amount      | Fair Value  |
| <i>(Thousands of dollars)</i>  |                 |            |                      |             |
| <b>Financial assets (liabilities):</b>   |                 |            |                      |             |
| Canadian government securities with maturities greater than 90 days at the date of acquisition | \$ 420,340      | 422,138    |                      |             |
| Current and long-term debt   | (1,028,794)     | (910,862)  | (1,521,364)          | (1,517,678) |

**Note O Hurricane and Insurance Related Matters**

In 2007 and 2006, the Company recorded pretax expenses, net of anticipated insurance recoveries, of \$3,000,000 and \$109,244,000, respectively, associated with hurricanes that occurred in the United States in 2005. The costs for the respective periods are reported in Net Costs Associated With Hurricanes in the Consolidated Statements of Income. The 2007 costs relate to a reduction in the estimated insurance recoverable on Meraux property damages based on the most recent estimate of loss limits as provided by the Company's primary property insurer. The components of the 2006 costs included \$107,410,000 at the Meraux refinery, including \$49,500,000 for refinery repair costs not expected to be recovered due to certain coverage limits for the Company's insurance policies; \$5,909,000 for incremental insurance costs; \$9,013,000 for other uninsured incremental expenses incurred; \$18,000,000 for settlement of oil spill class action litigation; and \$24,988,000 for depreciation and salaries while the refinery was temporarily idled prior to restarting in mid-2006. Total amounts receivable from insurers for hurricane-related matters were \$74,562,000 at December 31, 2008, of which \$48,030,000 was classified as current in the Consolidated Balance Sheet. Through 2008, the Company's refining and marketing operations received Hurricane Katrina insurance proceeds of \$118,040,000 related to property damage incurred as a result of Hurricane Katrina. See Note Q for additional information regarding environmental and other contingencies relating to Hurricane Katrina.

The Company maintains insurance coverage related to losses of production and profits for occurrences such as storms, fires and other issues. During 2007, the Company's exploration and production operations recorded \$2,048,000 in business interruption insurance recoveries relating to Hurricane Rita in 2005. In 2006, the Company recorded \$15,700,000 in business interruption insurance recoveries relating to Hurricane Katrina in 2005, and \$5,000,000 due to lost production at Terra Nova related to the mechanical failure of the main power generator. These business interruption collections were reported in Sales and Other Operating Revenues in the Consolidated Statements of Income.

**Note P Commitments**

The Company leases land, gasoline stations, and production and other facilities under operating leases. The most significant operating lease is associated with the Kikeh field floating, production, storage and offloading facility in Malaysia, which was initiated in 2007 for an eight-year term prior to start-up of this significant oil field. During the next five years, expected future rental payments under all operating leases are approximately \$96,276,000 in 2009, \$94,435,000 in 2010, \$86,570,000 in 2011, \$82,841,000 in 2012 and \$82,260,000 in 2013. Rental expense for noncancellable operating leases, including contingent payments when applicable, was \$88,890,000 in 2008, \$61,439,000 in 2007 and \$46,336,000 in 2006.

To assure long-term supply of hydrogen at its Meraux, Louisiana refinery, the Company has contracted to purchase up to 35 million standard cubic feet of hydrogen per day at market prices through 2021. The contract requires the payment of a base facility charge for use of the facility. Future required minimum annual payments for base facility charges for the next five years are \$6,625,000 in 2009, \$6,890,000 in 2010, \$7,166,000 in 2011, \$7,452,000 in 2012 and \$7,750,000 in 2013. Base facility charges and hydrogen costs incurred in 2008, 2007 and 2006 totaled \$45,396,000, \$42,512,000 and \$23,903,000, respectively. There were no base facility charges or hydrogen costs incurred at the Meraux refinery for the first four months of 2006 while the facility was shut-down for repairs after Hurricane Katrina.



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The Company has operating, production handling and transportation agreements providing for processing, production handling and transportation services for hydrocarbon production from certain fields in the Gulf of Mexico and Western Canada. These agreements require minimum monthly or annual payments for processing or transportation charges through 2013. Future required minimum monthly payments for

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the next five years are \$4,654,000 in 2009, \$9,036,000 in 2010, \$10,512,000 in 2011, \$7,770,000 in 2012 and \$2,249,000 in 2013. Under certain circumstances, the Company is required to pay additional amounts depending on the actual hydrocarbon quantities processed under the agreement. Costs incurred under these arrangements were \$9,276,000 in 2008, \$13,476,000 in 2007 and \$27,007,000 in 2006.

Additionally, the Company has a Reserved Capacity Service Agreement providing for the availability of needed crude oil storage capacity for certain oil fields through 2020. Under the agreement, the Company must make specified minimum payments monthly. Future required minimum annual payments are approximately \$3,500,000 in 2009 through 2013. In addition, the Company is required to pay additional amounts depending on actual crude oil quantities under the agreement. Total payments under the agreement were \$3,703,000 in 2008, \$3,992,000 in 2007 and \$3,666,000 in 2006.

In 2006, the Company committed to fund an educational assistance program known as the El Dorado Promise. Under this commitment, the Company will pay \$5,000,000 per year from 2007 to 2016 to cover a specified amount of college expenses for eligible graduates of El Dorado High School in Arkansas. The first three payments have been made through January 2009. Based on SFAS 116, Accounting for Contributions Received and Contributions Made, the Company recorded a discounted liability of \$38,700,000 in 2006 for this unconditional commitment. The liability was discounted at the Company's 10-year borrowing rate and the discounted liability will increase for accretion monthly with a corresponding charge to Selling and General Expense in the Consolidated Statement of Income. Total accretion cost included in Selling and General Expense in 2008 and 2007 was \$1,931,000 and \$2,112,000, respectively.

Commitments for capital expenditures were approximately \$2,129,136,000 at December 31, 2008, including \$172,900,000 for costs to develop deepwater Gulf of Mexico fields, \$1,015,755,000 for field development and future work commitments in Malaysia, and \$322,528,000 for field development and a work commitment in the Republic of the Congo.

The Company has entered into contracts to hire various drilling rigs and associated equipment for periods beyond December 31, 2008. These rigs are primarily utilized for deepwater drilling operations in the Gulf of Mexico, Malaysia, Canada, Australia and the Republic of the Congo. Future commitments under these contracts, all of which expire by 2012, total approximately \$865,000,000. A significant portion of these costs are expected to be borne by other working interest owners as partners of the Company when the wells are drilled. These drilling costs are generally expected to be accounted for as capital expenditures as incurred during the contract periods.

**Note Q Contingencies**

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

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

The Company currently owns or leases, and has in the past owned or leased, properties at which hazardous substances have been or are being handled. Although the Company has used operating and disposal practices that were standard in the industry at the time, hazardous substances may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes were not under Murphy's control. Under existing laws the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. While some of these historical properties are in various stages of negotiation, investigation, and/or cleanup, the Company is investigating the extent of any such liability and the availability of applicable defenses and believes costs related to these sites will not have a material adverse affect on Murphy's net income, financial condition or liquidity in a future period.



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The Company's liability for remedial obligations includes certain amounts that are based on anticipated regulatory approval for proposed remediation of former refinery waste sites. Although regulatory authorities may require more costly alternatives than the proposed processes, the cost of such potential alternative processes is not expected to exceed the accrued liability by a material amount. Certain environmental expenditures are likely to be recovered by the Company from other sources, primarily environmental funds maintained by certain states. Since no assurance can be given that future recoveries from other sources will occur, the Company has not recorded a benefit for likely recoveries at December 31, 2008.

The U.S. Environmental Protection Agency (EPA) currently considers the Company to be a Potentially Responsible Party (PRP) at two Superfund sites. The potential total cost to all parties to perform necessary remedial work at these sites 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 these Superfund sites. The Company has not recorded a liability for remedial costs on Superfund sites. 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 the two sites or other Superfund sites. The Company believes that its share of the ultimate costs to clean-up the Superfund sites will be immaterial and will not have a material adverse effect on its net income, financial condition or liquidity in a future period.

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

**LEGAL MATTERS** On September 9, 2005, a class action lawsuit was filed in federal court in the Eastern District of Louisiana seeking unspecified damages to the class comprised of residents of St. Bernard Parish caused by a release of crude oil at Murphy Oil USA, Inc.'s (a wholly-owned subsidiary of Murphy Oil Corporation) Meraux, Louisiana, refinery as a result of flood damage to a crude oil storage tank following Hurricane Katrina. Additional class action lawsuits were consolidated with the first suit into a single action in the U.S. District Court for the Eastern District of Louisiana. In September 2006, the Company reached a settlement with class counsel and on October 10, 2006, the court granted preliminary approval of a class action Settlement Agreement. A Fairness Hearing was held January 4, 2007 and the court entered its ruling on January 30, 2007 approving the class settlement. The majority of the settlement of \$330 million will be paid by insurance. The Company recorded an expense of \$18 million in 2006 related to settlement costs not expected to be covered by insurance. As part of the settlement, all properties in the class area received a fair and equitable cash payment and have had residual oil cleaned. As part of the settlement, the Company offered to purchase all properties in an agreed area adjacent to the west side of the Meraux refinery; these property purchases and associated remediation have been paid by the Company at a cost of \$55 million. As of December 31, 2008, the Company has fulfilled its obligations under the Class Action Settlement Agreement. Approximately 40 non-class action suits regarding the oil spill have been filed and remain pending. The Company believes that insurance coverage exists and it does not expect to incur significant costs associated with this litigation. On August 14, 2007, four of the Company's high level excess insurers noticed the Company for arbitration in London. The insurers do not deny coverage, but seek arbitration as to whether and to what extent expenditures made by the Company in resolving the oil spill litigation have reached the attachment point for covered loss under their respective policies. The Company is of the position that full coverage should be afforded. Accordingly, the Company believes neither the ultimate resolution of the remaining litigation nor the insurance arbitration will have a material adverse effect on its net income, financial condition or liquidity in a future period.

On June 10, 2003, a fire severely damaged the Residual Oil Supercritical Extraction (ROSE) unit at the Company's Meraux, Louisiana refinery. The ROSE unit recovers feedstock from the heavy fuel oil stream for conversion into gasoline and diesel. Subsequent to the fire, numerous class action lawsuits have been filed seeking damages for area residents. All the lawsuits have been administratively consolidated into a single legal action in St. Bernard Parish, Louisiana, except for one such action which was filed in federal court. Additionally, individual residents of Orleans Parish, Louisiana, have filed an action in that venue. On May 5, 2004, plaintiffs in the consolidated action in St. Bernard Parish amended their petition to include a direct action against certain of the Company's liability insurers. The St. Bernard Parish action has since been removed to federal court, which issued an order on July 25, 2008 denying plaintiff's request to certify the case as a class action. In responding to this direct action, one of the Company's insurers, AEGIS, has raised lack of coverage as a defense. The Company believes that this contention lacks merit and has been advised by counsel that the applicable policy does provide coverage for the underlying incident. Because the Company believes that insurance coverage exists for this matter, it does not expect to incur any significant costs associated with the lawsuits. Accordingly, the Company continues to believe that the ultimate resolution of the June 2003 ROSE fire litigation will not have a material adverse effect on its net income, financial condition or liquidity in a future period.

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



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**OTHER MATTERS** 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. At December 31, 2008, the Company had contingent liabilities of \$7,798,000 under a financial guarantee described in the following paragraph and \$120,029,000 on outstanding letters of credit. The Company has not accrued a liability in its balance sheet related to these letters of credit because it is believed that the likelihood of having these drawn is remote.

The Company owns a 3.2% interest in the Louisiana Offshore Oil Port (LOOP) that it accounts for at cost. At year-end 2008, LOOP had \$243,690,000 of outstanding bonds, which mature in varying amounts between 2014 and 2027 and which are secured by a Throughput and Deficiency Agreement (T&D). The Company is obligated to ship crude oil in quantities sufficient for LOOP to pay certain of its expenses and obligations, including long-term debt secured by the T&D, or to make cash payments for which the Company will receive credit for future throughput. No other collateral secures the investee's obligation or the Company's guarantee. As of December 31, 2008, it is not probable that the Company will be required to make payments under the guarantee; therefore, no liability has been recorded for the Company's obligation under the T&D agreement. The Company continues to monitor conditions that are subject to guarantees to identify whether it is probable that a loss has occurred, and it would recognize any such losses under the guarantees should losses become probable.

The joint agreement between the owners of Terra Nova requires a redetermination of working interests based on an analysis of reservoir quality among fault separated areas where varying ownership interests exist. The operator expects to complete the initial redetermination in March 2009, and the calculation is expected to be the subject of renegotiation and/or arbitration before final interests are determined. This redetermination is expected to be finalized in 2010, and is retroactive to 2005. Upon completion of the redetermination process, a cash settlement is required among partners to balance cash flows retroactive to the effective date. The Company cannot predict the final outcome of the redetermination process.

**Note R Common Stock Issued and Outstanding**

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2008 is shown below.

| <i>(Number of shares outstanding)</i>       | 2008        | 2007        | 2006        |
|---|-------------|-------------|-------------|
| At beginning of year                        | 189,714,149 | 187,572,200 | 185,946,678 |
| Stock options exercised                     | 1,275,971   | 2,249,300   | 1,374,827   |
| Employee stock purchase and thrift plans    | 19,755      | 37,679      | 28,280      |
| Restricted stock awards, net of forfeitures | (299,334)   | (144,442)   | 222,415     |
| All other                                   | 3,265       | (588)       |             |
| At end of year                              | 190,713,806 | 189,714,149 | 187,572,200 |

**Note S Business Segments**

Murphy's reportable segments are organized into two major types of business activities, each subdivided into geographic areas of operations. The Company's exploration and production activity is subdivided into segments for the United States, Canada, the United Kingdom, Malaysia, Ecuador and all other countries; each of these segments derives revenues primarily from the sale of crude oil and/or natural gas. The Company's refining and marketing segments are North America and the United Kingdom and each derives revenue mainly from the sale of petroleum products and merchandise. The Company sells gasoline in the United States at retail stations built primarily at Walmart Supercenters. The U.S. refining and marketing business and the former Canadian marketing business are included in the North American segment. In 2007, the Company exited the gasoline marketing business in Canada by closing and writing off all eight gasoline stations in that country. The Company's management evaluates segment performance based on income from operations, excluding interest income and interest expense. Intersegment transfers of crude oil, natural gas and petroleum products are at market prices and intersegment services are recorded at cost.

Information about business segments and geographic operations is reported in the following tables. For geographic purposes, revenues are attributed to the country in which the sale occurs. The Company had no single customer from which it derived more than 10% of its revenues. Corporate and other activities, including interest income, miscellaneous gains and losses, interest expense and unallocated overhead, are shown in the tables to reconcile the business segments to consolidated totals. As used in the table on page F-30, Certain Long-Lived Assets at December 31 exclude investments, noncurrent receivables, deferred tax assets and goodwill and other intangible assets.

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Excise taxes on petroleum products of \$2,140,338,000, \$2,070,077,000 and \$1,741,707,000 for the years 2008, 2007 and 2006, respectively, that were collected by the Company and remitted to various government entities were excluded from revenues and costs and expenses.

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| Segment Information<br>(Millions of dollars) | Exploration and Production               |                |              |                |             |              | Total          |
|--|--|----------------|--------------|----------------|-------------|--------------|----------------|
|  | U.S.                                     | Canada         | U.K.         | Malaysia       | Ecuador     | Other        |                |
| <b>Year ended December 31, 2008</b>          |  |                |              |                |             |              |                |
| Segment income (loss)                        | \$ 156.6                                 | 588.7          | 73.8         | 865.3          | (2.9)       | (81.6)       | 1,599.9        |
| Revenues from external customers             | 529.1                                    | 1,210.0        | 215.8        | 2,000.6        | 80.2        | 1.8          | 4,037.5        |
| Intersegment revenues                        |  | 166.5          | .2           |                |             |              | 166.7          |
| Interest income                              |  |                |              |                |             |              |                |
| Interest expense, net of capitalization      |  |                |              |                |             |              |                |
| Income tax expense (benefit)                 | 85.8                                     | 244.7          | 72.9         | 552.9          | 5.0         |              | 961.3          |
| Significant noncash charges (credits)        |  |                |              |                |             |              |                |
| Depreciation, depletion, amortization        | 110.0                                    | 139.4          | 28.9         | 248.4          | 45.7        | 1.1          | 573.5          |
| Accretion of asset retirement obligations    | 6.2                                      | 8.3            | 2.4          | 5.9            |             | .7           | 23.5           |
| Amortization of undeveloped leases           | 25.2                                     | 85.9           |              |                |             | .9           | 112.0          |
| Deferred and noncurrent income taxes         | 25.6                                     | (.5)           | 3.0          | 176.2          |             | (3.2)        | 201.1          |
| Additions to property, plant, equipment      | 366.4                                    | 470.7          | 31.7         | 664.1          | 6.9         | 163.1        | 1,702.9        |
| Total assets at year-end                     | 1,458.3                                  | 2,017.0        | 210.8        | 2,675.4        | 74.6        | 450.7        | 6,886.8        |
| <b>Year ended December 31, 2007</b>          |  |                |              |                |             |              |                |
| Segment income (loss)                        | \$ 98.2                                  | 370.2          | 47.6         | 148.2          | 28.5        | (35.6)       | 657.1          |
| Revenues from external customers             | 429.8                                    | 873.0          | 146.6        | 435.7          | 126.1       | 4.5          | 2,015.7        |
| Intersegment revenues                        |  | 130.3          | .1           |                |             |              | 130.4          |
| Interest income                              |  |                |              |                |             |              |                |
| Interest expense, net of capitalization      |  |                |              |                |             |              |                |
| Income tax expense (benefit)                 | 45.1                                     | 122.3          | 48.4         | 109.8          | 20.7        | .7           | 347.0          |
| Significant noncash charges (credits)        |  |                |              |                |             |              |                |
| Depreciation, depletion, amortization        | 74.5                                     | 183.8          | 20.7         | 57.9           | 39.2        | .7           | 376.8          |
| Accretion of asset retirement obligations    | 4.0                                      | 5.5            | 2.0          | 4.0            |             | .6           | 16.1           |
| Amortization of undeveloped leases           | 17.5                                     | 14.2           |              |                |             | 1.5          | 33.2           |
| Impairment of long-lived assets              | 2.6                                      |                |              |                |             |              | 2.6            |
| Deferred and noncurrent income taxes         | 35.7                                     | (51.0)         | 5.6          | 77.0           |             | 1.5          | 68.8           |
| Additions to property, plant, equipment      | 243.1                                    | 537.2          | 31.8         | 629.1          | 40.1        | 129.5        | 1,610.8        |
| Total assets at year-end                     | 1,130.2                                  | 2,327.8        | 198.9        | 2,110.2        | 130.7       | 431.6        | 6,329.4        |
| <b>Year ended December 31, 2006</b>          |  |                |              |                |             |              |                |
| Segment income (loss)                        | \$ 212.4                                 | 330.6          | 60.7         | (5.9)          | 38.4        | (19.4)       | 616.8          |
| Revenues from external customers             | 626.9                                    | 674.1          | 180.6        | 219.6          | 122.7       | 3.7          | 1,827.6        |
| Intersegment revenues                        |  | 118.3          |              |                |             |              | 118.3          |
| Interest income                              |  |                |              |                |             |              |                |
| Interest expense, net of capitalization      |  |                |              |                |             |              |                |
| Income tax expense (benefit)                 | 110.8                                    | 102.1          | 73.7         | 35.7           | 24.9        | .9           | 348.1          |
| Significant noncash charges (credits)        |  |                |              |                |             |              |                |
| Depreciation, depletion, amortization        | 85.2                                     | 114.7          | 22.1         | 47.2           | 27.3        | .5           | 297.0          |
| Accretion of asset retirement obligations    | 3.0                                      | 4.6            | 1.8          | .8             |             | .6           | 10.8           |
| Amortization of undeveloped leases           | 17.3                                     | 3.7            |              |                |             | 1.5          | 22.5           |
| Deferred and noncurrent income taxes         | (5.7)                                    | (3.9)          | 13.0         | 15.0           |             | (.6)         | 17.8           |
| Additions to property, plant, equipment      | 112.0                                    | 181.5          | 27.8         | 505.9          | 34.8        | 24.1         | 886.1          |
| Total assets at year-end                     | 880.2                                    | 1,761.3        | 185.4        | 1,386.0        | 145.2       | 98.6         | 4,456.7        |
| <b>Geographic Information</b>                |  |                |              |                |             |              |                |
| (Millions of dollars)                        | Certain Long-Lived Assets at December 31 |                |              |                |             |              | Total          |
|  | U.S.                                     | Canada         | U.K.         | Malaysia       | Ecuador     | Other        |                |
| <b>2008</b>                                  | <b>\$ 2,671.1</b>                        | <b>1,880.6</b> | <b>591.6</b> | <b>2,277.0</b> | <b>70.7</b> | <b>244.4</b> | <b>7,735.4</b> |
| 2007   | 2,187.5                                  | 2,103.6        | 678.0        | 1,818.4        | 106.5       | 223.9        | 7,117.9        |
| 2006   | 1,804.3                                  | 1,519.7        | 353.2        | 1,236.3        | 103.2       | 97.7         | 5,114.4        |



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| Segment Information (Continued)<br>(Millions of dollars) | Refining and Marketing |         |          | Corp. &<br>Other | Consolidated |
|--|------------------------|---------|----------|------------------|--------------|
|  | North America          | U.K.    | Total    |                  |              |
| <b>Year ended December 31, 2008</b>                      |                        |         |          |                  |              |
| Segment income (loss)                                    | \$ 227.9               | 85.9    | 313.8    | (173.7)          | 1,740.0      |
| Revenues from external customers                         | 18,927.0               | 4,639.1 | 23,566.1 | (91.1)           | 27,512.5     |
| Intersegment revenues                                    |                        |         |          |                  | 166.7        |
| Interest income  |                        |         |          | 40.8             | 40.8         |
| Interest expense, net of capitalization                  |                        |         |          | 43.7             | 43.7         |
| Income tax expense (benefit)                             | 134.6                  | 38.1    | 172.7    | (55.4)           | 1,078.6      |
| Significant noncash charges (credits)                    |                        |         |          |                  |              |
| Depreciation, depletion, amortization                    | 97.2                   | 36.9    | 134.1    | 5.4              | 713.0        |
| Accretion of asset retirement obligations                | 1.0                    |         | 1.0      |                  | 24.5         |
| Amortization of undeveloped leases                       |                        |         |          |                  | 112.0        |
| Deferred and noncurrent income taxes                     | 16.4                   | 5.3     | 21.7     | 10.1             | 232.9        |
| Additions to property, plant, equipment                  | 341.3                  | 84.9    | 426.2    | 3.2              | 2,132.3      |
| Total assets at year-end                                 | 2,314.5                | 805.6   | 3,120.1  | 1,142.2          | 11,149.1     |
| <b>Year ended December 31, 2007</b>                      |                        |         |          |                  |              |
| Segment income (loss)                                    | \$ 230.4               | (24.7)  | 205.7    | (96.3)           | 766.5        |
| Revenues from external customers                         | 15,050.9               | 1,358.2 | 16,409.1 | 14.3             | 18,439.1     |
| Intersegment revenues                                    |                        |         |          |                  | 130.4        |
| Interest income  |                        |         |          | 34.2             | 34.2         |
| Interest expense, net of capitalization                  |                        |         |          | 25.6             | 25.6         |
| Income tax expense (benefit)                             | 126.3                  | (5.4)   | 120.9    | 2.8              | 470.7        |
| Significant noncash charges (credits)                    |                        |         |          |                  |              |
| Depreciation, depletion, amortization                    | 91.2                   | 16.8    | 108.0    | 5.0              | 489.8        |
| Accretion of asset retirement obligations                | .1                     |         | .1       |                  | 16.2         |
| Amortization of undeveloped leases                       |                        |         |          |                  | 33.2         |
| Impairment of long-lived assets                          | 38.1                   |         | 38.1     |                  | 40.7         |
| Deferred and noncurrent income taxes                     | (1.7)                  | 1.0     | (.7)     | 34.4             | 102.5        |
| Additions to property, plant, equipment                  | 321.7                  | 250.8   | 572.5    | 4.1              | 2,187.4      |
| Total assets at year-end                                 | 2,378.4                | 1,024.5 | 3,402.9  | 803.5            | 10,535.8     |
| <b>Year ended December 31, 2006</b>                      |                        |         |          |                  |              |
| Segment income (loss)                                    | \$ 77.5                | 33.1    | 110.6    | (82.7)           | 644.7        |
| Revenues from external customers                         | 11,441.8               | 1,019.7 | 12,461.5 | 18.3             | 14,307.4     |
| Intersegment revenues                                    |                        |         |          |                  | 118.3        |
| Interest income  |                        |         |          | 26.5             | 26.5         |
| Interest expense, net of capitalization                  |                        |         |          | 9.5              | 9.5          |
| Income tax expense (benefit)                             | 39.8                   | 15.3    | 55.1     | (9.5)            | 393.7        |
| Significant noncash charges (credits)                    |                        |         |          |                  |              |
| Depreciation, depletion, amortization                    | 70.7                   | 13.0    | 83.7     | 3.4              | 384.1        |
| Accretion of asset retirement obligations                | .1                     |         | .1       |                  | 10.9         |
| Amortization of undeveloped leases                       |                        |         |          |                  | 22.5         |
| Deferred and noncurrent income taxes                     | 13.0                   | (2.3)   | 10.7     | 4.6              | 33.1         |
| Additions to property, plant, equipment                  | 163.6                  | 9.8     | 173.4    | 6.3              | 1,065.8      |
| Total assets at year-end                                 | 2,004.3                | 369.6   | 2,373.9  | 652.6            | 7,483.2      |

**Geographic Information**  
(Millions of dollars)

|             | Revenues from External Customers for the Year |         |         |          |         |       |          |
|-------------|---|---------|---------|----------|---------|-------|----------|
|             | U.S.  | U.K.    | Canada  | Malaysia | Ecuador | Other | Total    |
| <b>2008</b> | \$ 19,352.5                                   | 4,855.1 | 1,222.3 | 2,000.6  | 80.2    | 1.8   | 27,512.5 |
| 2007        | 15,450.4                                      | 1,507.6 | 913.7   | 435.7    | 126.1   | 5.6   | 18,439.1 |
| 2006        | 12,029.5                                      | 1,203.6 | 724.6   | 219.7    | 126.2   | 3.8   | 14,307.4 |

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**MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES**

**SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)**

The following unaudited schedules are presented in accordance with SFAS No. 69, Disclosures about Oil and Gas Producing Activities, to provide users with a common base for preparing estimates of future cash flows and comparing reserves among companies. Additional background information follows concerning four of the schedules.

**SCHEDULES 1 AND 2 ESTIMATED NET PROVED OIL AND NATURAL GAS RESERVES** Reserves of crude oil, condensate, natural gas liquids, natural gas and synthetic oil are estimated by the Company's engineers and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors.

The U.S. Securities and Exchange Commission defines proved reserves as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered as a result of additional investments for drilling new wells to offset productive units, recompleting existing wells, and/or installing facilities to collect and transport production.

Production quantities shown are net volumes withdrawn from reservoirs. These may differ from sales quantities due to inventory changes, volumes consumed for fuel and/or shrinkage from extraction of natural gas liquids. Estimated net proved oil reserves shown in Schedule 1 include natural gas liquids.

Oil reserves in Ecuador are derived from a participation contract covering Block 16 in the Amazon region. This Block 16 contract expires in early 2012. Oil reserves associated with the participation contract in Ecuador totaled 4.8 million barrels at December 31, 2008. Oil and natural gas reserves in Malaysia are associated with production sharing contracts for Blocks SK 309/311 and K. Malaysia reserves include oil and gas to be received for both cost recovery and profit provisions under the contracts. Oil and natural gas reserves associated with the production sharing contracts in Malaysia totaled 100.7 million barrels and 405.2 billion cubic feet, respectively, at December 31, 2008.

The Company has no proved reserves attributable to investees accounted for by the equity method.

At December 31, 2008, proved reserves are included for several fields where development projects are ongoing, including one field in the Gulf of Mexico, a natural gas development at Tupper in British Columbia and in Malaysia for natural gas projects at Sarawak and Kikeh and an oil development at Kakap.

Synthetic oil reserves in Canada, shown in a separate table following the natural gas reserve table at Schedule 2, are attributable to Murphy's 5% share, after deducting estimated net profit royalty, of the Syncrude project and include currently producing leases. Additional reserves will be added as development progresses.

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**Recent SEC Reserve Changes**

On December 29, 2008, the U.S. Securities and Exchange Commission adopted revisions to oil and natural gas reserve reporting requirements which are effective for the Company at year-end 2009, unless the timing is subsequently amended. Among other things, the rule:

revises the definition of proved reserves, including the pricing used to determine economic producibility,

expands the definition of oil and gas producing activities to include non-traditional and unconventional resources, which includes the Company's synthetic oil operations in Alberta, and

allows, but does not require, companies to disclose probable and possible reserves in SEC filings.

The Company is currently evaluating these new rules and cannot predict how the new rules will affect its future reporting of oil and natural gas reserves.

**SCHEDULE 4 RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES** Results of operations from exploration and production activities by geographic area are reported as if these activities were not part of an operation that also refines crude oil and sells refined products.

**SCHEDULE 5 STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES** SFAS No. 69 requires calculation of future net cash flows using a 10% annual discount factor and year-end prices, costs and statutory tax rates, except for known future changes such as contracted prices and legislated tax rates. Future net cash flows from the Company's interest in synthetic oil are excluded.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future cash flows because prices, costs and governmental policies do not remain static; appropriate discount rates may vary; and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts. SFAS No. 69 requires that oil and natural gas prices as of the last business day of the year be used for calculation of the standardized measure of discounted future net cash flows.

Schedule 5 also presents the principal reasons for change in the standardized measure of discounted future net cash flows for each of the three years ended December 31, 2008.

**Table of Contents****Schedule 1 Estimated Net Proved Oil Reserves**

| <i>(Millions of barrels)</i>    | United States | Canada      | United Kingdom | Malaysia     | Ecuador    | Total        |
|---------------------------------|---------------|-------------|----------------|--------------|------------|--------------|
| <b>Proved</b>                   |               |             |                |              |            |              |
| December 31, 2005               | 48.9          | 45.8        | 23.3           | 47.5         | 16.5       | 182.0        |
| Revisions of previous estimates | (2.6)         | 2.4         |                | 2.3          | (2.3)      | (.2)         |
| Improved recovery               |               | .3          |                |              |            | .3           |
| Purchases of properties         |               | .3          |                |              |            | .3           |
| Extensions and discoveries      | 5.4           | 5.1         |                | 8.6          |            | 19.1         |
| Production                      | (7.7)         | (10.2)      | (2.6)          | (4.1)        | (3.1)      | (27.7)       |
| December 31, 2006               | 44.0          | 43.7        | 20.7           | 54.3         | 11.1       | 173.8        |
| Revisions of previous estimates | (8.9)         | 3.6         |                | 3.2          | (.4)       | (2.5)        |
| Extensions and discoveries      | .9            | 2.2         |                | 32.5         |            | 35.6         |
| Production                      | (4.8)         | (11.3)      | (1.9)          | (7.4)        | (3.3)      | (28.7)       |
| December 31, 2007               | 31.2          | 38.2        | 18.8           | 82.6         | 7.4        | 178.2        |
| Revisions of previous estimates | (1.5)         | (1.9)       |                | 13.3         | .1         | 10.0         |
| Improved recovery               |               |             |                | 18.4         |            | 18.4         |
| Extensions and discoveries      | 1.0           | 1.1         |                | 7.4          |            | 9.5          |
| Production                      | (3.9)         | (9.3)       | (1.8)          | (21.0)       | (2.7)      | (38.7)       |
| Sales of properties             |               | (3.8)       |                |              |            | (3.8)        |
| <b>December 31, 2008</b>        | <b>26.8</b>   | <b>24.3</b> | <b>17.0</b>    | <b>100.7</b> | <b>4.8</b> | <b>173.6</b> |
| <b>Proved Developed</b>         |               |             |                |              |            |              |
| December 31, 2005               | 28.3          | 43.5        | 20.0           | 7.3          | 8.2        | 107.3        |
| December 31, 2006               | 26.7          | 41.1        | 18.0           | 4.8          | 8.5        | 99.1         |
| December 31, 2007               | 19.1          | 36.6        | 16.1           | 38.6         | 7.2        | 117.6        |
| <b>December 31, 2008</b>        | <b>16.7</b>   | <b>23.1</b> | <b>14.5</b>    | <b>63.4</b>  | <b>4.8</b> | <b>122.5</b> |

**Table of Contents****Schedule 2 Estimated Net Proved Natural Gas Reserves**

| <i>(Billions of cubic feet)</i> | United States | Canada        | United Kingdom | Malaysia      | Total         |
|---------------------------------|---------------|---------------|----------------|---------------|---------------|
| <b>Proved</b>                   |               |               |                |               |               |
| December 31, 2005               | 178.1         | 24.6          | 28.1           |               | 230.8         |
| Revisions of previous estimates | (14.2)        | (1.6)         |                | 74.6          | 58.8          |
| Purchases of properties         |               | 2.0           |                |               | 2.0           |
| Extensions and discoveries      | 5.4           |               |                | 262.9         | 268.3         |
| Production                      | (20.7)        | (4.1)         | (3.7)          |               | (28.5)        |
| December 31, 2006               | 148.6         | 20.9          | 24.4           | 337.5         | 531.4         |
| Revisions of previous estimates | (19.1)        | 7.7           |                | (2.2)         | (13.6)        |
| Extensions and discoveries      | .9            | 5.8           | 1.9            | 88.7          | 97.3          |
| Production                      | (17.1)        | (4.5)         | (2.7)          |               | (24.3)        |
| December 31, 2007               | 113.3         | 29.9          | 23.6           | 424.0         | 590.8         |
| Revisions of previous estimates | <b>1.1</b>    | <b>.8</b>     |                | <b>(45.4)</b> | <b>(43.5)</b> |
| Improved recovery               |               |               |                | <b>1.9</b>    | <b>1.9</b>    |
| Extensions and discoveries      | <b>.8</b>     | <b>56.0</b>   |                | <b>25.3</b>   | <b>82.1</b>   |
| Production                      | <b>(17.8)</b> | <b>(1.8)</b>  | <b>(2.8)</b>   | <b>(.6)</b>   | <b>(23.0)</b> |
| Sales of properties             |               | <b>(22.7)</b> |                |               | <b>(22.7)</b> |
| <b>December 31, 2008</b>        | <b>97.4</b>   | <b>62.2</b>   | <b>20.8</b>    | <b>405.2</b>  | <b>585.6</b>  |
| <b>Proved Developed</b>         |               |               |                |               |               |
| December 31, 2005               | 75.2          | 24.2          | 26.0           |               | 125.4         |
| December 31, 2006               | 70.6          | 20.6          | 22.3           |               | 113.5         |
| December 31, 2007               | 70.8          | 26.4          | 21.5           | 62.4          | 181.1         |
| <b>December 31, 2008</b>        | <b>58.8</b>   | <b>52.0</b>   | <b>18.9</b>    | <b>79.5</b>   | <b>209.2</b>  |

**Information on Proved Reserves for Canadian Synthetic Oil Operation Not Included in Net Proved Oil Reserves**

The Company has a 5% interest in Syncrude, the world's largest tar sands synthetic oil production project located in Alberta, Canada. In addition to conventional liquids and natural gas proved reserves, Murphy has significant proved synthetic oil reserves associated with Syncrude that are shown in the table below. For internal management purposes, Murphy views these reserves and ongoing production and development as an integral part of its total Exploration and Production operations. However, the U.S. Securities and Exchange Commission's regulations define Syncrude as a mining operation, and therefore, do not permit these synthetic oil proved reserves to be included as a part of conventional oil and natural gas reserves. These reserves are also not included in the Company's schedule of Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, which can be found on page F-39.

## Synthetic Oil Proved Reserves

(Millions of barrels)

|                          |              |
|--------------------------|--------------|
| December 31, 2005        | 133.1        |
| December 31, 2006        | 125.9        |
| December 31, 2007        | 128.4        |
| <b>December 31, 2008</b> | <b>131.6</b> |

**Table of Contents****Schedule 3 Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities**

| (Millions of dollars)               | United States | Canada <sup>1</sup> | United Kingdom | Malaysia | Ecuador | Other | Total   |
|-------------------------------------|---------------|---------------------|----------------|----------|---------|-------|---------|
| <b>Year Ended December 31, 2008</b> |               |                     |                |          |         |       |         |
| Property acquisition costs          |               |                     |                |          |         |       |         |
| Unproved                            | \$ 125.7      | 20.6                |                |          |         | 9.7   | 156.0   |
| Proved                              |               |                     |                |          |         |       |         |
| Total acquisition costs             | 125.7         | 20.6                |                |          |         | 9.7   | 156.0   |
| Exploration costs <sup>2</sup>      | 142.4         | 18.8                | 10.2           | 97.2     |         | 61.1  | 329.7   |
| Development costs <sup>2</sup>      | 168.9         | 421.7               | 27.2           | 687.9    | 6.9     | 152.4 | 1,465.0 |
| Total costs incurred                | 437.0         | 461.1               | 37.4           | 785.1    | 6.9     | 223.2 | 1,950.7 |
| Charged to expense                  |               |                     |                |          |         |       |         |
| Dry hole expense                    | 18.0          |                     |                | 80.4     |         | 31.1  | 129.5   |
| Geophysical and other costs         | 40.2          | 18.9                | .5             | 14.3     |         | 29.0  | 102.9   |
| Total charged to expense            | 58.2          | 18.9                | .5             | 94.7     |         | 60.1  | 232.4   |
| Property additions                  | \$ 378.8      | 442.2               | 36.9           | 690.4    | 6.9     | 163.1 | 1,718.3 |
| <b>Year Ended December 31, 2007</b> |               |                     |                |          |         |       |         |
| Property acquisition costs          |               |                     |                |          |         |       |         |
| Unproved                            | \$ 23.4       | 399.2               |                |          |         |       | 422.6   |
| Proved                              |               |                     |                |          |         |       |         |
| Total acquisition costs             | 23.4          | 399.2               |                |          |         |       | 422.6   |
| Exploration costs <sup>2</sup>      | 112.8         | 31.1                | .8             | 43.9     | .3      | 19.3  | 208.2   |
| Development costs <sup>2</sup>      | 215.8         | 126.9               | 31.2           | 646.2    | 40.1    | 129.3 | 1,189.5 |
| Total costs incurred                | 352.0         | 557.2               | 32.0           | 690.1    | 40.4    | 148.6 | 1,820.3 |
| Charged to expense                  |               |                     |                |          |         |       |         |
| Dry hole expense                    | 41.5          | 7.8                 |                | 17.9     | .3      | (.4)  | 67.1    |
| Geophysical and other costs         | 34.6          | 32.7                | .8             | 15.2     |         | 19.5  | 102.8   |
| Total charged to expense            | 76.1          | 40.5                | .8             | 33.1     | .3      | 19.1  | 169.9   |
| Property additions                  | \$ 275.9      | 516.7               | 31.2           | 657.0    | 40.1    | 129.5 | 1,650.4 |
| <b>Year Ended December 31, 2006</b> |               |                     |                |          |         |       |         |
| Property acquisition costs          |               |                     |                |          |         |       |         |
| Unproved                            | \$ 13.0       | .9                  |                |          |         |       | 13.9    |
| Proved                              |               |                     |                |          |         |       |         |
| Total acquisition costs             | 13.0          | .9                  |                |          |         |       | 13.9    |
| Exploration costs <sup>2</sup>      | 119.2         | 4.9                 |                | 185.6    | 1.5     | 26.8  | 338.0   |
| Development costs <sup>2</sup>      | 72.5          | 138.3               | 30.4           | 460.3    | 34.8    | 4.6   | 740.9   |
| Total costs incurred                | 204.7         | 144.1               | 30.4           | 645.9    | 36.3    | 31.4  | 1,092.8 |

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|                             |          |       |      |       |      |      |       |
|-----------------------------|----------|-------|------|-------|------|------|-------|
| Charged to expense          |          |       |      |       |      |      |       |
| Dry hole expense            | 56.4     | .2    |      | 52.5  | 1.5  | .4   | 111.0 |
| Geophysical and other costs | 30.6     | 1.2   | .2   | 46.8  |      | 6.9  | 85.7  |
| Total charged to expense    | 87.0     | 1.4   | .2   | 99.3  | 1.5  | 7.3  | 196.7 |
| Property additions          | \$ 117.7 | 142.7 | 30.2 | 546.6 | 34.8 | 24.1 | 896.1 |

<sup>1</sup> Excludes property additions for the Company's 5% interest in synthetic oil operations in Canada of \$35.6 million in 2008, \$23.6 million in 2007 and \$42.2 million in 2006.

<sup>2</sup> Includes non-cash asset retirement costs as follows:

|                   |         |     |      |       |  |  |      |
|-------------------|---------|-----|------|-------|--|--|------|
| 2008              |         |     |      |       |  |  |      |
| Exploration costs | \$ 6.1  |     |      |       |  |  | 6.1  |
| Development costs | 6.3     | 7.1 | 5.2  | 26.3  |  |  | 44.9 |
|                   | \$ 12.4 | 7.1 | 5.2  | 26.3  |  |  | 51.0 |
| 2007              |         |     |      |       |  |  |      |
| Exploration costs | \$ 2.5  |     |      |       |  |  | 2.5  |
| Development costs | 30.3    | 3.1 | (.6) | 27.9  |  |  | 60.7 |
|                   | \$ 32.8 | 3.1 | (.6) | 27.9  |  |  | 63.2 |
| 2006              |         |     |      |       |  |  |      |
| Exploration costs | \$ 2.6  |     |      | (2.6) |  |  |      |
| Development costs | 3.1     | 3.4 | 2.4  | 43.3  |  |  | 52.2 |
|                   | \$ 5.7  | 3.4 | 2.4  | 40.7  |  |  | 52.2 |

**Table of Contents****Schedule 4 Results of Operations for Oil and Gas Producing Activities**

| <i>(Millions of dollars)</i>              | United States | Canada | United Kingdom | Malaysia | Ecuador | Other  | Subtotal | Synthetic Oil Canada | Total   |
|---|---------------|--------|----------------|----------|---------|--------|----------|----------------------|---------|
| <b>Year Ended December 31, 2008</b>       |               |        |                |          |         |        |          |                      |         |
| Revenues                                  |               |        |                |          |         |        |          |                      |         |
| Crude oil and natural gas liquids         |               |        |                |          |         |        |          |                      |         |
| Sales to unaffiliated enterprises         | \$ 374.0      | 697.5  | 189.2          | 1,985.6  | 80.2    |        | 3,326.5  | 371.4                | 3,697.9 |
| Transfers to consolidated operations      |               | 78.3   | .2             |          |         |        | 78.5     | 88.2                 | 166.7   |
| Natural gas                               |               |        |                |          |         |        |          |                      |         |
| Sales to unaffiliated enterprises         | 162.1         | 5.5    | 25.8           | .1       |         |        | 193.5    |                      | 193.5   |
| Total oil and gas revenues                | 536.1         | 781.3  | 215.2          | 1,985.7  | 80.2    |        | 3,598.5  | 459.6                | 4,058.1 |
| Other operating revenues                  | (7.0)         | 133.1  | .8             | 14.9     |         | 1.8    | 143.6    | 2.5                  | 146.1   |
| Total revenues                            | 529.1         | 914.4  | 216.0          | 2,000.6  | 80.2    | 1.8    | 3,742.1  | 462.1                | 4,204.2 |
| Costs and expenses                        |               |        |                |          |         |        |          |                      |         |
| Production expenses                       | 67.0          | 88.3   | 32.9           | 234.4    | 31.4    |        | 454.0    | 188.6                | 642.6   |
| Exploration costs charged to expense      | 58.2          | 18.9   | .5             | 94.7     |         | 60.1   | 232.4    |                      | 232.4   |
| Undeveloped lease amortization            | 25.2          | 85.9   |                |          |         | .9     | 112.0    |                      | 112.0   |
| Depreciation, depletion and amortization  | 110.0         | 111.1  | 28.9           | 248.4    | 45.7    | 1.1    | 545.2    | 28.3                 | 573.5   |
| Accretion of asset retirement obligations | 6.2           | 4.4    | 2.4            | 5.9      |         | .7     | 19.6     | 3.9                  | 23.5    |
| Selling and general expenses              | 20.1          | 12.6   | 4.6            | (1.0)    | 1.0     | 20.6   | 57.9     | .8                   | 58.7    |
| Minority interest                         |               | .3     |                |          |         |        | .3       |                      | .3      |
| Total costs and expenses                  | 286.7         | 321.5  | 69.3           | 582.4    | 78.1    | 83.4   | 1,421.4  | 221.6                | 1,643.0 |
| Income tax expense                        | 242.4         | 592.9  | 146.7          | 1,418.2  | 2.1     | (81.6) | 2,320.7  | 240.5                | 2,561.2 |
| Income tax expense                        | 85.8          | 169.1  | 72.9           | 552.9    | 5.0     |        | 885.7    | 75.6                 | 961.3   |
| Results of operations*                    | \$ 156.6      | 423.8  | 73.8           | 865.3    | (2.9)   | (81.6) | 1,435.0  | 164.9                | 1,599.9 |
| <b>Year Ended December 31, 2007</b>       |               |        |                |          |         |        |          |                      |         |
| Revenues                                  |               |        |                |          |         |        |          |                      |         |
| Crude oil and natural gas liquids         |               |        |                |          |         |        |          |                      |         |
| Sales to unaffiliated enterprises         | \$ 310.8      | 559.3  | 129.4          | 436.0    | 126.1   |        | 1,561.6  | 290.4                | 1,852.0 |
| Transfers to consolidated operations      |               | 69.3   | .1             |          |         |        | 69.4     | 61.0                 | 130.4   |
| Natural gas                               |               |        |                |          |         |        |          |                      |         |
| Sales to unaffiliated enterprises         | 121.7         | 23.0   | 16.6           |          |         |        | 161.3    |                      | 161.3   |
| Total oil and gas revenues                | 432.5         | 651.6  | 146.1          | 436.0    | 126.1   |        | 1,792.3  | 351.4                | 2,143.7 |
| Other operating revenues                  | (2.7)         | .3     | .6             | (.3)     |         | 4.5    | 2.4      |                      | 2.4     |
| Total revenues                            | 429.8         | 651.9  | 146.7          | 435.7    | 126.1   | 4.5    | 1,794.7  | 351.4                | 2,146.1 |
| Costs and expenses                        |               |        |                |          |         |        |          |                      |         |
| Production expenses                       | 80.4          | 104.4  | 23.5           | 73.7     | 36.6    |        | 318.6    | 144.4                | 463.0   |
| Exploration costs charged to expense      | 76.1          | 40.5   | .8             | 33.1     | .3      | 19.1   | 169.9    |                      | 169.9   |
| Undeveloped lease amortization            | 17.5          | 14.2   |                |          |         | 1.5    | 33.2     |                      | 33.2    |
| Depreciation, depletion and amortization  | 74.5          | 157.3  | 20.7           | 57.9     | 39.2    | .7     | 350.3    | 26.5                 | 376.8   |
| Accretion of asset retirement obligations | 4.0           | 4.8    | 2.0            | 4.0      |         | .6     | 15.4     | .7                   | 16.1    |
| Impairment of long-lived assets           | 2.6           |        |                |          |         |        | 2.6      |                      | 2.6     |



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|                              |         |       |      |       |      |        |       |       |         |
|------------------------------|---------|-------|------|-------|------|--------|-------|-------|---------|
| Selling and general expenses | 31.4    | 17.7  | 3.7  | 9.0   | .8   | 17.5   | 80.1  | .8    | 80.9    |
| Minority interest            |         | (.5)  |      |       |      |        | (.5)  |       | (.5)    |
| Total costs and expenses     | 286.5   | 338.4 | 50.7 | 177.7 | 76.9 | 39.4   | 969.6 | 172.4 | 1,142.0 |
|                              | 143.3   | 313.5 | 96.0 | 258.0 | 49.2 | (34.9) | 825.1 | 179.0 | 1,004.1 |
| Income tax expense           | 45.1    | 79.7  | 48.4 | 109.8 | 20.7 | .7     | 304.4 | 42.6  | 347.0   |
| Results of operations*       | \$ 98.2 | 233.8 | 47.6 | 148.2 | 28.5 | (35.6) | 520.7 | 136.4 | 657.1   |

\* Excludes corporate overhead and interest.

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**Table of Contents****Schedule 4 Results of Operations for Oil and Gas Producing Activities (Contd.)**

| Year Ended December 31, 2006              | United States | Canada | United Kingdom | Malaysia | Ecuador | Other  | Subtotal | Synthetic Oil Canada | Total   |
|---|---------------|--------|----------------|----------|---------|--------|----------|----------------------|---------|
| <b>Revenues</b>                           |               |        |                |          |         |        |          |                      |         |
| Crude oil and natural gas liquids         |               |        |                |          |         |        |          |                      |         |
| Sales to unaffiliated enterprises         | \$ 440.1      | 407.4  | 156.8          | 219.6    | 122.7   |        | 1,346.6  | 220.3                | 1,566.9 |
| Transfers to consolidated operations      |               | 68.6   |                |          |         |        | 68.6     | 49.7                 | 118.3   |
| Natural gas                               |               |        |                |          |         |        |          |                      |         |
| Sales to unaffiliated enterprises         | 160.4         | 24.1   | 23.3           |          |         |        | 207.8    |                      | 207.8   |
| Total oil and gas revenues                | 600.5         | 500.1  | 180.1          | 219.6    | 122.7   |        | 1,623.0  | 270.0                | 1,893.0 |
| Other operating revenues                  | 26.4          | 22.3   | .5             |          |         | 3.7    | 52.9     |                      | 52.9    |
| Total revenues                            | 626.9         | 522.4  | 180.6          | 219.6    | 122.7   | 3.7    | 1,675.9  | 270.0                | 1,945.9 |
| <b>Costs and expenses</b>                 |               |        |                |          |         |        |          |                      |         |
| Production expenses                       |               |        |                |          |         |        |          |                      |         |
| Production expenses                       | 79.3          | 102.6  | 18.4           | 32.7     | 29.7    |        | 262.7    | 120.5                | 383.2   |
| Exploration costs charged to expense      | 87.0          | 1.4    | .2             | 99.3     | 1.5     | 7.3    | 196.7    |                      | 196.7   |
| Undeveloped lease amortization            | 17.3          | 3.7    |                |          |         | 1.5    | 22.5     |                      | 22.5    |
| Depreciation, depletion and amortization  | 85.2          | 97.1   | 22.1           | 47.2     | 27.3    | .5     | 279.4    | 17.6                 | 297.0   |
| Accretion of asset retirement obligations | 3.0           | 4.1    | 1.8            | .8       |         | .6     | 10.3     | .5                   | 10.8    |
| Net costs associated with hurricanes      | 1.9           |        |                |          |         |        | 1.9      |                      | 1.9     |
| Selling and general expenses              | 30.0          | 11.4   | 3.7            | 9.8      | .9      | 12.3   | 68.1     | .8                   | 68.9    |
| Total costs and expenses                  | 303.7         | 220.3  | 46.2           | 189.8    | 59.4    | 22.2   | 841.6    | 139.4                | 981.0   |
|   | 323.2         | 302.1  | 134.4          | 29.8     | 63.3    | (18.5) | 834.3    | 130.6                | 964.9   |
| Income tax expense                        | 110.8         | 72.4   | 73.7           | 35.7     | 24.9    | .9     | 318.4    | 29.7                 | 348.1   |
| Results of operations*                    | \$ 212.4      | 229.7  | 60.7           | (5.9)    | 38.4    | (19.4) | 515.9    | 100.9                | 616.8   |

\* Excludes corporate overhead and interest.

**Table of Contents****Schedule 5 Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves**

| <i>(Millions of dollars)</i>                             | United States | Canada* | United Kingdom | Malaysia  | Ecuador | Total     |
|--|---------------|---------|----------------|-----------|---------|-----------|
| <b>December 31, 2008</b>                                 |               |         |                |           |         |           |
| Future cash inflows                                      | \$ 1,722.0    | 999.6   | 751.0          | 5,602.3   | 128.5   | 9,203.4   |
| Future development costs                                 | (330.0)       | (26.3)  | (133.3)        | (924.8)   | (4.8)   | (1,419.2) |
| Future production and abandonment costs                  | (495.6)       | (445.0) | (254.8)        | (1,078.8) | (87.4)  | (2,361.6) |
| Future income taxes                                      | (217.9)       | (157.0) | (201.4)        | (1,336.8) |         | (1,913.1) |
| Future net cash flows                                    | 678.5         | 371.3   | 161.5          | 2,261.9   | 36.3    | 3,509.5   |
| 10% annual discount for estimated timing of cash flows   | (146.1)       | (62.2)  | (59.6)         | (572.3)   | (4.1)   | (844.3)   |
| Standardized measure of discounted future net cash flows | \$ 532.4      | 309.1   | 101.9          | 1,689.6   | 32.2    | 2,665.2   |
| <b>December 31, 2007</b>                                 |               |         |                |           |         |           |
| Future cash inflows                                      | \$ 3,564.8    | 2,905.0 | 1,955.7        | 7,813.6   | 214.0   | 16,453.1  |
| Future development costs                                 | (397.7)       | (19.1)  | (73.9)         | (1,504.3) | (19.9)  | (2,014.9) |
| Future production and abandonment costs                  | (542.0)       | (901.1) | (436.2)        | (1,674.6) | (141.5) | (3,695.4) |
| Future income taxes                                      | (849.8)       | (434.7) | (738.7)        | (1,381.6) | (15.2)  | (3,420.0) |
| Future net cash flows                                    | 1,775.3       | 1,550.1 | 706.9          | 3,253.1   | 37.4    | 7,322.8   |
| 10% annual discount for estimated timing of cash flows   | (489.1)       | (335.9) | (272.2)        | (750.5)   | (3.1)   | (1,850.8) |
| Standardized measure of discounted future net cash flows | \$ 1,286.2    | 1,214.2 | 434.7          | 2,502.6   | 34.3    | 5,472.0   |
| <b>December 31, 2006</b>                                 |               |         |                |           |         |           |
| Future cash inflows                                      | \$ 3,178.8    | 1,880.7 | 1,337.0        | 3,407.4   | 331.1   | 10,135.0  |
| Future development costs                                 | (398.8)       | (17.8)  | (53.7)         | (672.2)   | (53.8)  | (1,196.3) |
| Future production and abandonment costs                  | (567.3)       | (600.4) | (372.0)        | (479.9)   | (131.7) | (2,151.3) |
| Future income taxes                                      | (624.5)       | (318.1) | (468.9)        | (652.5)   | (48.0)  | (2,112.0) |
| Future net cash flows                                    | 1,588.2       | 944.4   | 442.4          | 1,602.8   | 97.6    | 4,675.4   |
| 10% annual discount for estimated timing of cash flows   | (444.0)       | (177.0) | (126.0)        | (385.4)   | (22.1)  | (1,154.5) |
| Standardized measure of discounted future net cash flows | \$ 1,144.2    | 767.4   | 316.4          | 1,217.4   | 75.5    | 3,520.9   |

\* Excludes discounted future net cash flows from synthetic oil of \$545.9 million at December 31, 2008, \$2,127.6 million at December 31, 2007 and \$1,096.0 million at December 31, 2006.

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

| <i>(Millions of dollars)</i>   | 2008         | 2007      | 2006      |
|--|--------------|-----------|-----------|
| Net changes in prices, production costs and development costs        | \$ (3,433.3) | 1,130.6   | (1,948.7) |
| Sales and transfers of oil and gas produced, net of production costs | (3,288.1)    | (1,476.1) | (1,413.2) |
| Net change due to extensions and discoveries                         | 825.4        | 1,919.6   | 1,026.0   |
| Net change due to purchases and sales of proved reserves             | (75.0)       |           | 8.8       |
| Development costs incurred   | 1,245.0      | 936.0     | 645.2     |
| Accretion of discount  | 798.5        | 508.8     | 613.6     |
| Revisions of previous quantity estimates                             | 164.0        | (121.8)   | 20.7      |

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|                                     |                   |         |         |
|-------------------------------------|-------------------|---------|---------|
| Net change in income taxes          | <b>956.7</b>      | (946.0) | 379.5   |
| Net increase (decrease)             | <b>(2,806.8)</b>  | 1,951.1 | (668.1) |
| Standardized measure at January 1   | <b>5,472.0</b>    | 3,520.9 | 4,189.0 |
| Standardized measure at December 31 | <b>\$ 2,665.2</b> | 5,472.0 | 3,520.9 |

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**Table of Contents****Schedule 6 Capitalized Costs Relating to Oil and Gas Producing Activities**

| <i>(Millions of dollars)</i>                         | United States | Canada  | United Kingdom | Malaysia | Ecuador | Other | Subtotal  | Synthetic Oil Canada | Total     |
|--|---------------|---------|----------------|----------|---------|-------|-----------|----------------------|-----------|
| <b>December 31, 2008</b>                             |               |         |                |          |         |       |           |                      |           |
| Unproved oil and gas properties                      | \$ 313.5      | 405.2   | 9.6            | 198.5    |         | 243.7 | 1,170.5   |                      | 1,170.5   |
| Proved oil and gas properties                        | 1,419.0       | 1,620.3 | 495.5          | 2,504.2  | 388.0   | 3.5   | 6,430.5   | 832.1                | 7,262.6   |
| Gross capitalized costs                              | 1,732.5       | 2,025.5 | 505.1          | 2,702.7  | 388.0   | 247.2 | 7,601.0   | 832.1                | 8,433.1   |
| Accumulated depreciation, depletion and amortization |               |         |                |          |         |       |           |                      |           |
| Unproved oil and gas properties                      | (59.3)        | (93.2)  |                |          |         | (9.7) | (162.2)   |                      | (162.2)   |
| Proved oil and gas properties                        | (543.7)       | (719.4) | (312.9)        | (430.8)  | (317.3) | (3.5) | (2,327.6) | (165.3)              | (2,492.9) |
| Net capitalized costs                                | \$ 1,129.5    | 1,212.9 | 192.2          | 2,271.9  | 70.7    | 234.0 | 5,111.2   | 666.8                | 5,778.0   |
| <b>December 31, 2007</b>                             |               |         |                |          |         |       |           |                      |           |
| Unproved oil and gas properties                      | \$ 216.9      | 483.1   |                | 191.2    |         | 223.9 | 1,115.1   |                      | 1,115.1   |
| Proved oil and gas properties                        | 1,154.2       | 1,831.0 | 468.2          | 1,823.0  | 381.1   | 3.6   | 5,661.1   | 911.2                | 6,572.3   |
| Gross capitalized costs                              | 1,371.1       | 2,314.1 | 468.2          | 2,014.2  | 381.1   | 227.5 | 6,776.2   | 911.2                | 7,687.4   |
| Accumulated depreciation, depletion and amortization |               |         |                |          |         |       |           |                      |           |
| Unproved oil and gas properties                      | (48.4)        | (27.5)  |                |          |         | (8.8) | (84.7)    |                      | (84.7)    |
| Proved oil and gas properties                        | (435.9)       | (923.7) | (287.7)        | (203.0)  | (274.6) | (3.6) | (2,128.5) | (171.3)              | (2,299.8) |
| Net capitalized costs                                | \$ 886.8      | 1,362.9 | 180.5          | 1,811.2  | 106.5   | 215.1 | 4,563.0   | 739.9                | 5,302.9   |

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

**Table of Contents****MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****SUPPLEMENTAL QUARTERLY INFORMATION (UNAUDITED)**

| <i>(Millions of dollars except per share amounts)</i> | First<br>Quarter | Second<br>Quarter | Third<br>Quarter | Fourth<br>Quarter | Year     |
|---|------------------|-------------------|------------------|-------------------|----------|
| <b>Year Ended December 31, 2008</b>                   |                  |                   |                  |                   |          |
| Sales and other operating revenues                    | \$ 6,489.9       | 8,268.1           | 8,203.3          | 4,479.5           | 27,440.8 |
| Income before income taxes                            | 657.9            | 969.6             | 920.1            | 271.0             | 2,818.6  |
| Net income  | 409.0            | 619.2             | 584.4            | 127.4             | 1,740.0  |
| Income per Common share basic                         | 2.16             | 3.27              | 3.08             | 0.67              | 9.18     |
| Income per Common share diluted                       | 2.14             | 3.22              | 3.04             | 0.67              | 9.06     |
| Cash dividend per Common share                        | .1875            | .1875             | .25              | .25               | .875     |
| Market price of Common Stock*                         |                  |                   |                  |                   |          |
| High  | 85.85            | 98.05             | 100.93           | 61.23             | 100.93   |
| Low   | 69.54            | 83.03             | 60.61            | 37.00             | 37.00    |
| <b>Year Ended December 31, 2007</b>                   |                  |                   |                  |                   |          |
| Sales and other operating revenues                    | \$ 3,427.6       | 4,614.6           | 4,773.0          | 5,608.6           | 18,423.8 |
| Income before income taxes                            | 200.4            | 404.3             | 318.1            | 314.4             | 1,237.2  |
| Net income  | 110.6            | 250.3             | 199.5            | 206.1             | 766.5    |
| Income per Common share basic                         | 0.59             | 1.33              | 1.06             | 1.09              | 4.08     |
| Income per Common share diluted                       | 0.58             | 1.32              | 1.04             | 1.07              | 4.01     |
| Cash dividend per Common share                        | .15              | .15               | .1875            | .1875             | .675     |
| Market price of Common Stock*                         |                  |                   |                  |                   |          |
| High  | 54.79            | 60.99             | 70.05            | 85.38             | 85.38    |
| Low   | 45.93            | 53.16             | 57.90            | 67.97             | 45.93    |

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

**Table of Contents****MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES****SCHEDULE II VALUATION ACCOUNTS AND RESERVES**

| <i>(Millions of dollars)</i>           | Balance at<br>January 1 | Charged<br>(Credited) to<br>Expense | Deductions | Other* | Balance at<br>December 31 |
|--|-------------------------|-------------------------------------|------------|--------|---------------------------|
| <b>2008</b>                            |                         |                                     |            |        |                           |
| Deducted from asset accounts:          |                         |                                     |            |        |                           |
| Allowance for doubtful accounts        | \$ 7.5                  | .1                                  | (.2)       | (.1)   | 7.3                       |
| Deferred tax asset valuation allowance | 214.1                   | 52.7                                |            |        | 266.8                     |
| <b>2007</b>                            |                         |                                     |            |        |                           |
| Deducted from asset accounts:          |                         |                                     |            |        |                           |
| Allowance for doubtful accounts        | \$ 10.4                 | .7                                  | (3.6)      |        | 7.5                       |
| Deferred tax asset valuation allowance | 205.8                   | 8.3                                 |            |        | 214.1                     |
| <b>2006</b>                            |                         |                                     |            |        |                           |
| Deducted from asset accounts:          |                         |                                     |            |        |                           |
| Allowance for doubtful accounts        | \$ 14.5                 | .3                                  | (4.6)      | .2     | 10.4                      |
| Deferred tax asset valuation allowance | 151.1                   | 54.7                                |            |        | 205.8                     |

\* Amounts primarily represent changes in foreign currency exchange rates.

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**GLOSSARY OF TERMS**

**3D seismic**

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

**bitumen or oil sands**

tar-like hydrocarbon-bearing substance that occurs naturally in certain areas at the Earth's surface or at relatively shallow depths

**deepwater**

offshore location in greater than 1,000 feet of water

**downstream**

refining and marketing operations

**dry hole**

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

**exploratory**

wildcat and delineation, e.g., exploratory wells

**feedstock**

crude oil, natural gas liquids and other materials used as raw materials for making gasoline and other refined products by the Company's refineries

**hydrocarbons**

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

**throughput**

average amount of raw material processed in a given period by a facility

**upstream**

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

**wildcat**

well drilled to target an untested or unproved geologic formation