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, 2007

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
Common Stock, $1.00 Par Value	**New York Stock Exchange**
Series A Participating Cumulative Preferred Stock Purchase Rights	**New York Stock Exchange**

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

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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, 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 is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on the last sale price at June 30, 2007 as quoted by the New York Stock Exchange, was approximately $11,204,643,000.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2008 was 189,730,149.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 14, 2008 have been incorporated by reference in Part III herein.

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MURPHY OIL CORPORATION

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PART I

Item 1. BUSINESS

Summary

Murphy Oil Corporation is a worldwide oil and gas exploration and production company with refining and marketing operations in the United 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 2007 Annual Report to Security Holders (2007 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 25, F-12 and F-13, F-31 through F-39, and F-41 of this Form 10-K report and on pages 6 and 7 of the 2007 Annual Report.

At December 31, 2007, Murphy had 7,539 employees, including 2,890 full-time and 4,649 part-time.

Interested parties may access the Company’s public disclosures filed with the Securities and Exchange Commission, 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.

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 2007, 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 and the Republic of Congo 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 2007 was in the United States, Canada, the United Kingdom, Malaysia and Ecuador; its natural gas was produced and sold in the United States, Canada and the United Kingdom. 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 2007 averaged 91,522 barrels per day, an increase of 4% compared to 2006. The increase was primarily due to start-up of production at the Kikeh field in Block K, offshore Sabah, Malaysia, in August 2007. Oil production was also higher in 2007 in Canada primarily due to a full year of production at Terra Nova and higher oil volumes at Syncrude. The Terra Nova field was shut down for major equipment maintenance for six months in 2006. Oil production in the U.S. Gulf of Mexico was lower in 2007 due to production declines at several fields. The Company’s worldwide sales volume of natural gas averaged 61 million cubic feet (MMCF) per day in 2007, down 19% from 2006 levels. The lower natural gas sales volumes were primarily attributable to production declines in 2007 for fields in South Louisiana and the Gulf of Mexico. Total worldwide 2007 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 101,702 barrels per day, up 1% compared to 2006.

Total production in 2008 is currently expected to average approximately 135,000 barrels of oil equivalent per day. The projected production increase in 2008 is related to a full year of oil production plus continued ramp up of volumes at the Kikeh field. In addition, initial natural gas production is expected during the year in Malaysia and from the Tupper area in western Canada. These improved volumes are expected to more than offset anticipated field declines in 2008 in the Gulf of Mexico, onshore South Louisiana and at Hibernia and Terra Nova.

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. Of the total producing fields at December 31, 2007, six are in the deepwater Gulf of Mexico and two are 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 13,000 barrels of oil per day and 45 million cubic feet of natural gas per day in the U.S. in 2007. These amounts represented 14% of total worldwide oil and 74% 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 40% of total production on a barrel of oil equivalent basis during 2007. The Company operates and holds a 60% interest in Medusa, which produced total daily net oil and natural gas of about 7,000 barrels and 7 MMCF, respectively, in 2007. At December 31, 2007, the Medusa field has total net proved oil and natural gas reserves of approximately 9 million barrels and 11 billion cubic feet, respectively. Production from Medusa is expected to continue to decline in 2008 and should average 4,900 barrels of oil and 4 MMCF of natural gas on a daily basis. Total oil and natural gas reserves in the U.S. at December 31, 2007 were 31.2 million barrels and 113.3 billion cubic feet, respectively.

In Canada, the Company owns an interest in three nonoperated significant, 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 two heavy oil areas and one natural gas area in the Western Canadian Sedimentary Basin (WCSB). Murphy has a 6.5% interest in Hibernia and a 12% interest in Terra Nova in the Jeanne d'Arc Basin, offshore Newfoundland. Total net production in 2007 was about 8,300 barrels of oil per day at Hibernia, while net production from Terra Nova was about 10,600 barrels of oil per day. Terra Nova was on production for all of 2007 following a six-month shut down for major equipment maintenance in 2006. Total 2008 net oil production at Hibernia and Terra Nova is anticipated to be approximately 7,100 and 8,700 barrels per day, respectively. Total net proved oil reserves at December 31, 2007 at Hibernia and Terra Nova were approximately 8.7 million barrels and 7.4 million barrels, respectively. Murphy owns a 5% undivided interest in Syncrude Canada Ltd., a joint venture located about 25 miles north of Fort McMurray, Alberta. Syncrude utilizes its assets to extract bitumen from oil sand deposits and to upgrade this bitumen into a high-value synthetic crude oil. Syncrude completed an expansion in 2006 by adding a third coker that allows for increased production. Total net production in 2007 was about 12,900 barrels of synthetic crude oil per day and is expected to average about 13,200 barrels per day in 2008. Although Syncrude produces a very high quality synthetic crude oil from bitumen, the U.S. Securities and Exchange Commission (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-35. Total net reserves for Syncrude at year-end 2007 were approximately 128.4 million barrels. Daily net production in 2007 in the WCSB averaged about 12,100 barrels of mostly heavy oil and about 10 MMCF of natural gas. WCSB oil and natural gas production in 2008 is expected to decline to 8,000 barrels and nine MMCF per day, with the reduction mostly due to planned property sales. In January 2008, Murphy sold its 80% interest in Berkana Energy Corp. for net proceeds of approximately Cdn $103.8 million. Through early 2008, the Company has acquired approximately 80,000 acres of mineral rights in northeastern British Columbia in an area named Tupper. Although the Company has booked no proved reserves at Tupper at year-end 2007, a significant natural gas development has been sanctioned by the Company's Board of Directors and development activities are underway. Initial natural gas production at Tupper is currently anticipated in the fourth quarter 2008.

Murphy produces oil and natural gas in the United Kingdom sector of the North Sea. Total 2007 net production in the U.K. amounted to about 5,300 barrels of oil per day and six MMCF of natural gas per day, which represented 6% of oil produced and 10% of natural gas produced by the Company during the year. Total 2008 net daily production levels in the U.K. are anticipated to average 4,600 barrels of oil and five MMCF of natural gas. Total proved reserves in the U.K. at December 31, 2007 were 18.8 million barrels of oil and 23.6 billion cubic feet of natural gas.

In Malaysia, the Company has majority interests in eight 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 February 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 8,700 net barrels of oil per day in 2007. Net production in 2008 is anticipated to decrease at these fields to about 4,900 barrels of oil per day due to field decline and a lower percentage of production allocable to the Company under the production sharing contract. The Company has also made multiple natural gas discoveries in these shallow-water Sarawak blocks. In February 2007, the Company finalized a gas sales contract for the Sarawak area with PETRONAS, the Malaysian state-owned oil company, with initial gas deliveries anticipated in the first quarter 2009. Total proved reserves of oil and natural gas at December 31, 2007 for Blocks SK 309/311 were 6.6 million barrels and 317 billion cubic feet of natural gas.

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, Kerisi and Jangas. 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 11,600 net barrels of oil per day for the full year 2007 and the field produced about 40,000 net barrels per day in December 2007. Net oil production at Kikeh is anticipated to average 56,000 barrels per day for 2008 as additional wells are completed and brought online. In February 2007, the Company signed a Kikeh field natural gas sales contract with PETRONAS. The natural gas development at Kikeh will lead to initial production beginning at mid-year 2008, with an average net volume of 67 MMCF per day in the fourth quarter and 35 MMCF per day for the full year. Total proved reserves booked in Block K as of year-end 2007 were 76 million barrels of oil and 107 billion cubic feet of natural gas. These proved oil reserves do not include any volumes attributable to pressure maintenance programs that the Company utilizes at the Kikeh field.

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. Murphy drilled an unsuccessful wildcat well in Block P during 2006. 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. 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 relinquished 75% interests in most of Block PM 311 and all of Block PM 312, located offshore peninsular Malaysia, during 2007. However, Murphy retained its 75% interest in two discoveries at Kenarong and Pertang in Block PM 311. Murphy has requested gas holding agreements for Kenarong and Pertang pending a further study of available development options.

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 9,000 barrels of oil per day in 2007 and is expected to average about 7,200 barrels per day in 2008, with the decline expected due to reduced development drilling after a late 2007 government sharing adjustment. 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 $23.28 per barrel at December 31, 2007) from 50% to 99%. The government had previously enacted a 50% revenue sharing rate in April 2006. The working interest owners in Block 16 intend to initiate 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 are actively negotiating a contract revision with the government.

The Company has interests in Production Sharing Agreements covering two offshore blocks in the Republic of Congo. These blocks are named Mer Profonde Sud (MPS) and Mer Profonde Nord (MPN), and together, cover approximately 1.8 million acres with water depths ranging from 490 to 6,900 feet. 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 2007, the Company continued its development of the Azurite field, with first oil production currently anticipated in 2009. In late 2007, the Company sold down its interest in the MPS block, including the Azurite field, from 85% to 50%, subject to the approval of the government of the Republic of Congo, which is expected in early 2008. The initial sales price was $83.5 million with additional consideration of up to $26.5 million contingent upon achieving certain financial and operating goals for Azurite field development. In addition, the Company will receive a partial carry on costs for two upcoming exploration wells in MPS. Once the transfer is approved by the Congolese government, the Company's net acreage will be reduced by approximately 495 thousand acres.

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 2.1 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 first of which is likely to be drilled in 2009.

The Company acquired a 40% interest and operatorship of an exploration permit covering approximately 1.0 million gross acres in Block AC/P36 in the Browse Basin offshore northwestern Australia in November 2007. The transfer of the interest to Murphy is pending government approval, which is expected in early 2008. Three-dimensional seismic was obtained in late 2007 and the first exploration well is anticipated to spud in late 2008.

Murphy's estimated net quantities of proved oil and gas reserves and proved developed oil and gas reserves at December 31, 2004, 2005, 2006 and 2007 by geographic area are reported on pages F-35 and F-36 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, 2007 are shown on page 6 of the 2007 Annual Report. In 2007, 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 20 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-34 through F-41 of this Form 10-K report.

At December 31, 2007, Murphy held leases, concessions, contracts or permits on developed and undeveloped acreage as shown by geographic area in the following table. Gross acres are those in which all or part of the working interest is owned by Murphy. Net acres are the portions of the gross acres attributable to Murphy's interest.

	Developed		Undeveloped		Total	
Area (Thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States – Onshore	3	2	190	118	193	120
– Gulf of Mexico	13	5	1,194	783	1,207	788
– Alaska	3	1	4	—	7	1
Total United States	19	8	1,388	901	1,407	909
Canada – Onshore	41	30	317	284	358	314
– Offshore	88	8	6,526	1,682	6,614	1,690
Total Canada	129	38	6,843	1,966	6,972	2,004
United Kingdom	33	4	40	6	73	10
Malaysia	7	6	9,628	6,521	9,635	6,527
Ecuador	7	1	524	105	531	106
Republic of Congo	—	—	1,773	1,201	1,773	1,201
Suriname	—	—	2,164	1,731	2,164	1,731
Spain	—	—	36	6	36	6
Totals	195	57	22,396	12,437	22,591	12,494
Oil sands – Syncrude	96	5	160	8	256	13

The above table excludes 191 thousand net acres held by Berkana Energy, a subsidiary which was sold by the Company in January 2008, and approximately 401 thousand net acres in Block AC/P36 in the Browse Basin offshore northwestern Australia that is pending government approval for the Company's acquisition. Significant undeveloped net acreage that expires in 2008 consists of approximately 299 thousand net acres in the Republic of Congo and 1,592 thousand net acres in Block H Malaysia. In 2010 net acreage expirations 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.

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, 2007.

	Oil Wells		Gas Wells	
Country	**Gross**	**Net**	**Gross**	**Net**
United States	34	9	14	6
Canada	502	387	20	12
United Kingdom	33	3	23	2
Malaysia	21	18	—	—
Ecuador	167	33	—	—
Totals	757	450	57	20

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
2007												
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**
2006												
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
2005												
Exploratory	1.5	2.2	—	—	—	0.5	10.2	5.0	2.0	4.2	13.7	11.9
Development	0.9	—	87.0	8.0	0.1	—	—	—	4.0	—	92.0	8.0

Murphy's drilling wells in progress at December 31, 2007 are shown below.

	Exploratory		Development		Total	
Country	Gross	Net	Gross	Net	Gross	Net
Canada	—	—	4.0	2.1	4.0	2.1
United Kingdom	—	—	2.0	0.1	2.0	0.1
Ecuador	—	—	2.0	0.4	2.0	0.4
Malaysia	1.0	0.8	—	—	1.0	0.8
Totals	1.0	0.8	8.0	2.6	9.0	3.4

Refining and Marketing

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. During 2007, the Company closed eight gasoline stations in Canada and no longer has gasoline marketing operations in that country.

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.

Refinery capacities at December 31, 2007 are shown in the following table.

	Meraux, Louisiana	Superior, Wisconsin	Milford Haven, 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	2,820,000	3,085,000	8,908,000	14,813,000

* 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, 2007, total receivables from insurance companies related to hurricane repairs at Meraux was $38.9 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 naptha hydrotreaters was revamped to a kerosine hydrotreater.

MOUSA markets refined products through a network of retail gasoline stations and branded and unbranded wholesale customers in a 23-state area of the southern and midwestern United States. Murphy's retail stations are primarily located in the parking lots of Wal-Mart Supercenters in 20 states and use the brand name Murphy USA®. The Company also markets gasoline and other products at standalone 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, 2007, the Company marketed products through 973 Murphy stations and 153 branded wholesale SPUR stations. MOUSA plans to build additional retail gasoline stations at Wal-Mart Supercenters and other standalone locations in 2008.

As of December 31, 2007 all but two of the Company's operated gasoline stations are located in the parking lots of Wal-Mart Supercenters. During 2007, the Company agreed to buy the land underlying most of these stations from Wal-Mart. Through February 2008, the Company had acquired 730 sites from Wal-Mart, and additional sites are expected to be purchased in the future. Ownership of the sites effectively terminates the master ground rent agreement as to these sites, and no further rent is payable to Wal-Mart for the purchased locations. For the remaining gasoline station sites not acquired from Wal-Mart, Murphy has master agreements that allow the Company to rent land from Wal-Mart. 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 Wal-Mart 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 these stations represented 48.8% of consolidated Company revenues in 2007, 51.7% in 2006 and 44.6% in 2005. As the Company continues to expand the number of gasoline stations at Wal-Mart Supercenters and other locations, 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. In December 2006, Murphy acquired an additional 10.7% interest in the first 22 miles of this pipeline from Clovelly to Alliance, Louisiana, thereby raising its ownership interest to 40.1%; the Company owns 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.

In 2007, Murphy owned approximately 1.0% of the crude oil refining capacity in the United States and its market share of U.S. retail gasoline sales was approximately 2.2%.

At the end of 2007, Murco distributed refined products in the United Kingdom from the wholly-owned Milford Haven refinery, three wholly owned terminals supplied by rail, six terminals owned by others where products are received in exchange for deliveries from the Company’s terminals, and 389 branded stations primarily under the brand name MURCO. The Company owns 162 of these branded stations and the remainder are branded dealers.

A statistical summary of key operating and financial indicators for each of the seven years ended December 31, 2007 are reported on page 7 of the 2007 Annual Report.

Item 1A. RISK FACTORS

Competition

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 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.

Reserve Replacement

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.

Proved Reserves

Proved crude oil and natural gas reserves included in this report on pages F-35 and F-36 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, 2007, approximately 34% of the Company's proved oil reserves and 69% 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, 2007, the Company's non-producing proved developed reserves represent approximately 5% 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.

Price Volatility

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 2007 was favorably affected by high crude oil and natural gas prices. If these prices decline significantly in 2008 or future years, the Company's results of operations would be negatively impacted. 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 West Texas Intermediate (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.

Dry Hole Exposure

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 overall net income. In 2007, significant wildcat wells were primarily drilled offshore Malaysia and in the U.S. Gulf of Mexico. The Company's 2008 budget calls for wildcat drilling primarily in the Gulf of Mexico, and in waters offshore Malaysia, the Republic of Congo and Australia.

Capital Financing

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. 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 development activities.

Limited Control

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. 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 2007 and 2006 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 2007, approximately 56% of the Company's total production was at fields operated by others, while at December 31, 2007, approximately 32% 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.

Outside Forces

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, 2007, approximately 58% 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" 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.

Industry and Other Risks

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 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.

Insurance

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, 2007, the Company maintained total excess liability insurance with limits of $750 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. There can be no assurance that such 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. 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 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. See Note Q in the consolidated financial statements for further discussion.

Litigation

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 10 of this Form 10-K report.

Credit Exposure

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.

Retirement Plans

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, 2007.

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-34 to F-41 and in Note E—Property, Plant and Equipment on page F-12.

Executive Officers of the Registrant

The age at January 1, 2008, 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.

Claiborne P. Deming – Age 53; President and Chief Executive Officer since October 1994 and Director and Member of the Executive Committee since 1993.

Steven A. Cossé – Age 60; 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 49; Executive Vice President responsible for the Company's worldwide refining and marketing operations and strategic planning effective January 1, 2007. Mr. Doerr served as President of Murphy Oil Company Ltd. from September 1997 through December 2006.

David M. Wood – Age 50; Executive Vice President responsible for the Company's worldwide exploration and production operations effective January 1, 2007. Mr. Wood served as President of Murphy Exploration & Production Company-International from March 2003 through December 2006 and was Senior Vice President of Frontier Exploration & Production from April 1999 through February 2003.

Kevin G. Fitzgerald – Age 52; 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 56; Senior Vice President since February 2005. Mr. Stobaugh joined the Company as Vice President in 1995.

Mindy K. West – Age 38; 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 49; Vice President and Controller since January 1, 2007. Mr. Eckart served as Controller since March 2000.

Walter K. Compton – Age 45; 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 will receive a fair and equitable cash payment and will have residual oil cleaned. As part of the settlement, the Company will offer to purchase all properties in an agreed area adjacent to the west side of the Meraux refinery; these property purchases and associated remediation will be paid by the Company and are expected to total $55 million. Approximately 75 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 where a class certification decision is pending. 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 class action 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 2007.

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 2,655 stockholders of record as of December 31, 2007. Information as to high and low market prices per share and dividends per share by quarter for 2007 and 2006 are reported on page F-42 of this Form 10-K report.

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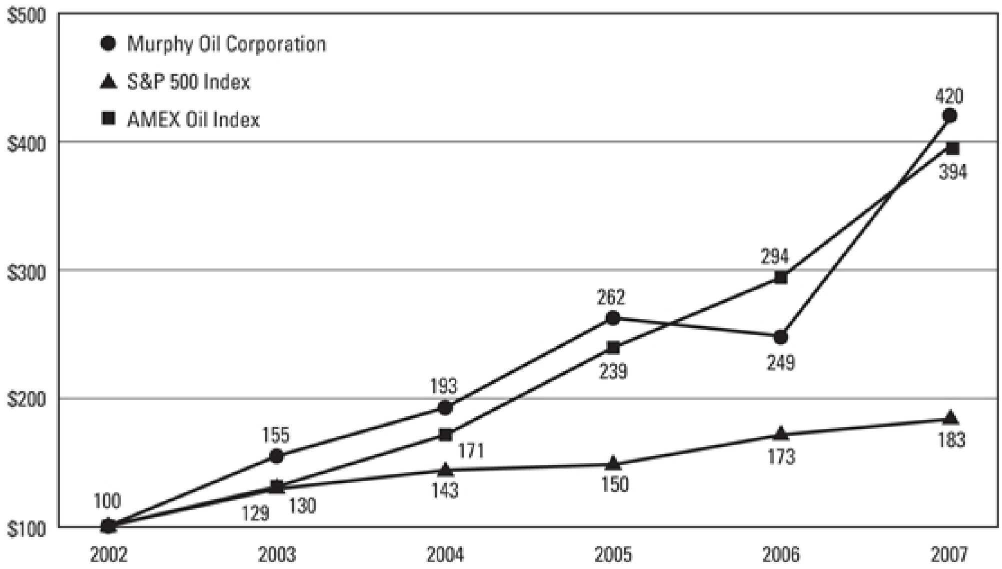
SHAREHOLDER RETURN PERFORMANCE PRESENTATION

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.

Murphy Oil Corporation
Comparison of Five-Year Cumulative Shareholder Returns
SOURCE: Bloomberg L.P.



	2002	2003	2004	2005	2006	2007
Murphy Oil Corporation	100	155	193	262	249	420
S&P 500 Index	100	129	143	150	173	183
AMEX Oil Index	100	130	171	239	294	394

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Item 6. SELECTED FINANCIAL DATA

(Thousands of dollars except per share data)	2007	2006	2005	2004	2003
Results of Operations for the Year					
Sales and other operating revenues	**$ 18,423,771**	14,279,325	11,680,079	8,299,147	5,094,518
Net cash provided by continuing operations	**1,740,420**	975,478	1,240,382	1,043,049	562,999
Income from continuing operations	**766,529**	644,669	846,193	500,208	278,927
Net income	**766,529**	644,669	854,742	705,128	294,714
Per Common share – diluted					
Income from continuing operations	**4.01**	3.41	4.50	2.68	1.50
Net income	**4.01**	3.41	4.55	3.77	1.59
Cash dividends per Common share	**.675**	.525	.45	.425	.40
Percentage return on					
Average stockholders' equity	**16.8**	16.8	28.0	30.7	16.1
Average borrowed and invested capital	**13.9**	14.4	23.5	21.6	10.8
Average total assets	**8.5**	9.3	14.6	13.4	6.6
Capital Expenditures for the Year					
Continuing operations					
Exploration and production	**$ 1,780,743**	1,082,756	1,091,954	839,182	689,632
Refining and marketing	**572,458**	173,400	202,401	134,706	215,362
Corporate and other	**4,146**	6,383	35,476	1,505	1,120
	2,357,347	1,262,539	1,329,831	975,393	906,114
Discontinued operations	**—**	—	—	9,065	73,050
	$ 2,357,347	1,262,539	1,329,831	984,458	979,164
Financial Condition at December 31					
Current ratio	**1.37**	1.61	1.43	1.35	1.28
Working capital	**$ 777,530**	795,986	551,938	424,372	228,529
Net property, plant and equipment	**7,109,822**	5,106,282	4,374,229	3,685,594	3,530,800
Total assets	**10,535,849**	7,483,161	6,410,396	5,498,903	4,769,808
Long-term debt	**1,516,156**	840,275	609,574	613,355	1,090,307
Stockholders' equity	**5,066,174**	4,121,273	3,522,070	2,702,632	1,999,391
Per share	**26.70**	21.97	18.94	14.68	10.88
Long-term debt – percent of capital employed	**23.0**	16.9	14.8	18.5	35.3

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 Wal-Mart 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 prices were higher in 2007 than in 2006, while the average price for North American natural gas was up only slightly in 2007 compared to 2006. The average price for a barrel of West Texas Intermediate crude oil in 2007 was $72.25, an increase of 9% compared to 2006. The NYMEX natural gas price in 2007 averaged $7.11 per million British Thermal Units (MMBTU), up 1% from 2006. 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 90% of the total hydrocarbons produced on an energy equivalent basis by the Company in 2007. If the prices for crude oil and natural gas decline significantly in 2008 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 2007 of $766.5 million, $4.01 per diluted share, compared to net income in 2006 of $644.7 million, $3.41 per diluted share. In 2005 the Company's net income was $854.7 million, $4.55 per diluted share. 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. The net cost of corporate activities was higher, however, in 2007 than in 2006. The lower net income in 2006 compared to 2005 was caused by a combination of lower earnings in the Company's exploration and production and refining and marketing operations and higher net costs for corporate activities. Further explanations of each of these variances are found in the following sections.

Income from continuing operations was $766.5 million, $4.01 per diluted share, in 2007, $644.7 million, $3.41 per diluted share, in 2006, and $846.1 million, $4.50 per diluted share, in 2005.

Income from discontinued operations was $8.6 million, $0.05 per diluted share, in 2005. There were no results from discontinued operations in 2007 and 2006. In the second quarter 2004 the Company sold most of its conventional oil and natural gas properties in western Canada for cash proceeds of $583 million, which generated an after-tax gain on the sale of $171.1 million in 2004. Income from discontinued operations in 2005 related to a favorable adjustment of income taxes associated with the gain on sale of the western Canada properties in 2004. In accordance with Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, the favorable tax adjustment associated with the sale in 2005 has been presented as Discontinued Operations in the consolidated statement of income for the year ended December 31, 2005.

As explained in Note P to the consolidated financial statements, net income in 2006 and all prior years have been adjusted to reflect the adoption of FSP AUG AIR-1, Accounting for Planned Major Maintenance Activities, in 2007. Consequently, net income in 2006 and 2005 as presented above increased by $6.4 million ($.04 per diluted share) and $8.2 million ($.04 per diluted share), respectively, from the amounts previously reported.

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 – exploration and production (" E&P") and refining and marketing ("R&M" or "downstream"). 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 record company profits in 2007, increasing $95.1 million compared to 2006. The improvement was primarily due to stronger 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. 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 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 $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 due mostly to higher losses on foreign currency exchange attributable to a continued weakening of the U.S. dollar against the primary foreign currencies affecting the Company's operations, which include the Canadian dollar, the British pound sterling, the Euro and the Malaysian ringgit. 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 in 2006 for hurricane-related repairs. 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 and gas field operations in Malaysia, the U.K. and Ecuador and for 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 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 the just completed year 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 additional 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 costs recorded in 2007 related to a downward adjustment for anticipated insurance recoveries at the Meraux refinery based on recently updated loss limits published by the Company's primary property insurer. Interest expense increased by $22.9 million in 2007 mostly associated with a higher average level of outstanding borrowings 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 levels of spending on E&P development projects in Malaysia, the U.S. and the Republic of 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.

2006 vs. 2005 – Net income in 2006 was $644.7 million, $3.41 per diluted share, compared to $854.7 million, $4.55 per diluted share, in 2005. Net income in 2005 included income from discontinued operations of $8.6 million, which was $0.05 per share. The $210.1 million decline in net income in 2006 was primarily due to lower earnings in both the Company's E&P and downstream businesses, plus higher net costs for corporate activities. The Company's E&P earnings declined by $133.2 million in 2006 due to several factors, including an after-tax gain of $104.5 million in 2005 related to a sale of most mature oil and natural gas properties on the continental shelf of the Gulf of Mexico, plus in 2006, lower sales volumes for crude oil and natural gas caused by lower production levels for these products, lower natural gas sales prices in North America and higher production and administrative expenses. The 2006 E&P results were favorably impacted by higher crude oil sales prices, lower exploration expenses, lower hurricane-related costs and higher income tax benefits due to various tax rate changes. Company-wide, the net costs associated with hurricanes were $42.5 million higher in 2006 compared to 2005. Hurricane costs in the Company's R&M business were $59.8 million higher in 2006 due to more uninsured costs associated with repairs at the Meraux, Louisiana refinery, clean-up of a crude oil spill that occurred at the refinery as a result of damages from Hurricane Katrina, and settlement of litigation associated with the oil spill. Hurricane costs in the Company's E&P business were lower in 2006 by $16.9 million due to lower costs for equipment and facilities repair, discretionary employee assistance and hurricane-related insurance. Earnings in the R&M business were $21.0 million lower in 2006 compared to 2005, with the earnings reduction primarily caused by the aforementioned higher hurricane-related costs. Excluding the higher hurricane costs, U.S. downstream earnings improved in 2006 compared to 2005, while 2006 earnings for downstream operations in the U.K. were down $7.4 million from record levels in 2005. The Company continued to expand its retail gasoline station business by adding 123 sites in 2006, with virtually all such additions located at Wal-Mart Supercenters. The net costs of corporate activities were $47.2 million higher in 2006 than 2005. These costs increased mostly due to an educational assistance contribution commitment amounting to $25.1 million after-tax, plus the unfavorable effects of foreign currency exchange movements as the U.S. dollar weakened against most other major currencies used by the Company's operations, including the British pound sterling and Euro. In addition, corporate activity costs in 2006 were unfavorable because 2005 included income tax benefits of $9.7 million from settlement of U.S. income tax audits.

Sales and other operating revenues in 2006 were $2.6 billion higher than in 2005 mostly due to higher sales volumes and sales prices in the latter year for refined petroleum products. In addition, merchandise sales at retail gasoline stations increased in 2006 and the sales price of crude oil was higher in 2006. Revenue was unfavorably affected in 2006 by lower sales volumes of crude oil and lower sales volumes and prices for natural gas. Gain on sale of assets before income taxes amounted to $9.4 million in 2006 compared to $175.1 million in 2005. The prior year included a pretax gain of $165.0 million related to the sale of oil and natural gas properties on the Gulf of Mexico continental shelf. Interest and other income in 2006 was unfavorable to the prior year by $3.3 million due mostly to higher foreign exchange charges associated with the unfavorable effects of the U.S. dollar weakening against the British pound sterling and Euro. Crude oil and product purchases expense increased by $2.4 billion in 2006 compared to 2005 due to higher prices for crude oil and other purchased refinery feedstocks, higher prices and volumes of refined petroleum products purchased for sale at retail gasoline stations, and higher levels of merchandise purchased for sale at these gasoline stations. These higher costs were partially offset by lower volumes of crude oil purchased for feedstock in 2006 because the Meraux refinery was off-line for repairs for the first five months of the year. Operating expenses increased by $257.5 million in 2006 compared to 2005 due to higher repairs and other production expenses in the Company's E&P operations, higher costs to operate retail gasoline stations primarily due to more stations in operation, and higher refinery operating costs mostly associated with increased labor costs at the Company's Meraux refinery. Exploration expenses were lower in 2006 compared to 2005 by $13.2 million primarily due to lower dry hole charges in the current year in the Republic of Congo, but partially offset by higher dry hole and seismic and geophysical costs in the U.S. Selling and general expenses increased $69.7 million in 2006 due to various factors during the year, including costs for an educational assistance contribution commitment, the costs of reorganizing the Company's U.S. E&P operations, higher costs for professional consultants, and the initial costs to expense the grant-date fair value of stock options which began in 2006. Depreciation, depletion and amortization expense was $12.8 million lower in 2006 than 2005 generally due to lower volumes of crude oil and natural gas sold by the Company's E&P business. Depreciation expense in the downstream business was higher in 2006 mostly due to the continued addition of retail gasoline stations in the U.S. Accretion of asset retirement obligations increased by $1.2 million in 2006 mostly due to higher asset retirement obligations for Malaysian operations associated with drilling development wells at the Kikeh field during the year. The reasons for higher costs associated with hurricanes in 2006 were included in the previous paragraph. Interest expense increased in 2006 by $5.2 million due to higher average borrowings under the Company's credit facilities. The amount of interest costs capitalized to development projects increased by $4.5 million in 2006 compared to 2005 due to higher capitalized costs associated with the Kikeh field, offshore Sabah Malaysia, and a field in the deepwater Gulf of Mexico. Income tax expense in 2006 was lower than in 2005 by $145.2 million due to lower pretax earnings in 2006 and net tax benefits in the year from changes in tax rates in various taxing jurisdictions. The effective income tax rate for consolidated earnings in 2006 was 37.9% and included a net benefit of $19.7 million from the reduction of Federal and provincial tax rates in Canada offset in part by an increase in the tax rate on oil operations in the U.K. The effective tax rate in 2005 was 38.9% of consolidated pretax earnings. 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 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.

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Segment Results – In the following table, the Company's results of operations for the three years ended December 31, 2007 are presented by segment. More detailed reviews of operating results for the Company's exploration and production and refining and marketing activities follow the table.

(Millions of dollars)	2007	2006	2005
Exploration and production			
United States	**$ 98.2**	212.4	385.5
Canada	**370.2**	330.6	310.1
United Kingdom	**47.6**	60.7	79.9
Malaysia	**148.2**	(5.9)	(4.7)
Ecuador	**28.5**	38.4	38.1
Other	**(35.6)**	(19.4)	(58.9)
	657.1	616.8	750.0
Refining and marketing			
North America	**230.4**	77.5	91.1
United Kingdom	**(24.7)**	33.1	40.5
	205.7	110.6	131.6
Corporate and other	**(96.3)**	(82.7)	(35.5)
Income from continuing operations	**766.5**	644.7	846.1
Income from discontinued operations	**—**	—	8.6
Net income	**$ 766.5**	644.7	854.7

Exploration and Production – Earnings from exploration and production operations were $657.1 million in 2007, $616.8 million in 2006 and $750.0 million in 2005. E&P earnings improved in 2007 compared to 2006 primarily due to higher average realized oil sales prices 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 crude oil inventory, which is primarily at the Kikeh field in Malaysia, is expected to return 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 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, 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 the average North American natural gas sales price was 5% lower in 2007.

The $133.2 million reduction in 2006 earnings compared to 2005 was mostly attributable to lower production of crude oil and natural gas, which led to lower sales volumes for these products. Lower natural gas sales prices and higher production and administrative expenses in 2006 and a $104.5 million after-tax gain on sale of oil and natural gas properties on the continental shelf of the Gulf of Mexico in 2005 also were factors that led to lower E&P earnings in 2006. E&P earnings in 2006 were favorably impacted by higher realized oil sales prices, lower exploration expenses, lower hurricane-related expenses and income tax benefits associated with tax rate changes enacted during the year. Crude oil sales volumes were down in 2006 by 13% compared to 2005, while natural gas sales volumes were down by 17%. Oil sales volumes were lower in 2006 primarily due to lower production at maturing fields in the Gulf of Mexico, lower production at the Terra Nova field, offshore Newfoundland, due to the field being shut-in for six months for major equipment repairs, and lower production at West Patricia, offshore Sarawak Malaysia, due to a lower volumetric sharing percentage allocable to the Company under the production sharing contract as the field matures. The decline in natural gas sales volumes in 2006 was attributable to both the mid-2005 sale of mature gas properties on the Gulf of Mexico continental shelf and lower production from gas fields onshore south Louisiana. The Company's average worldwide realized crude oil sales price increased 14% in 2006, while the average realized sales price for North American natural gas decreased 10%.

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-38 and F-39 of this Form 10-K report. Average daily production and sales rates and weighted average sales prices are shown on page 6 of the 2007 Annual Report.

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

(Millions of dollars)	2007	2006	2005
United States			
Oil and gas liquids	**$ 310.8**	440.1	448.8
Natural gas	**121.7**	160.4	216.6
Canada			
Conventional oil and gas liquids	**628.6**	476.0	519.7
Natural gas	**23.0**	24.1	29.7
Synthetic oil	**351.4**	270.0	224.7
United Kingdom			
Oil and gas liquids	**129.5**	156.8	159.8
Natural gas	**16.6**	23.3	19.9
Malaysia – crude oil	**436.0**	219.6	232.9
Ecuador – crude oil	**126.1**	122.7	116.6
Total oil and gas revenues	**$ 2,143.7**	1,893.0	1,968.7

The Company's crude oil, condensate and natural gas liquids production averaged 91,522 barrels per day in 2007, 87,817 barrels per day in 2006 and 101,349 barrels per day in 2005. In 2007, crude oil, condensate and natural gas liquid production increased by 3,705 barrels per day, or 4%, primarily due to start-up in August of the Kikeh field in Block K, offshore Sabah, Malaysia. This prolific field came on only five years after discovery. Kikeh produced 11,658 barrels of oil per day for the full-year 2007 and almost 40,000 barrels per day in December 2007. This field will continue to ramp-up production during 2008 as more wells are brought on production. 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 Western Canadian Sedimentary Basin (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 at Block 16 in Ecuador, up 338 barrels per day due to a more significant development drilling campaign 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 compared to 10,996 barrels per day in 2006. The Hibernia field is experiencing production decline. 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 is also experiencing declining production along with an increased government take under the production sharing contract.

Production of crude oil, condensate and natural gas liquids was 13% lower in 2006 compared to 2005 primarily due to lower volumes produced in the U.S. Gulf of Mexico and offshore eastern Canada. U.S. oil production of 21,112 barrels per day in 2006 was down by 18% from 2005 levels. The reduction in the U.S. related to lower volumes at deepwater fields in the Gulf of Mexico and oil volumes produced in 2005 from fields on the continental shelf that were sold in the middle of that year. U.S. oil production in 2006 was virtually unaffected by downtime for tropical storms and hurricanes, while 2005 volumes were adversely affected by downtime associated with Hurricanes Katrina and Rita. Terra Nova, offshore eastern Canada, was off production for about one-half of 2006 for major equipment repairs. The floating production, storage and offloading vessel was taken to Europe for turnaround and production restarted in mid-November 2006. Production at Terra Nova was 3,900 barrels per day in 2006, down 64% from 2005 levels. Production at Hibernia totaled 10,996 barrels per day, which was 10% below 2005, with the decline due primarily to more downtime for equipment reliability issues in 2006. Total heavy oil production in WCSB increased 7% in 2006 and totaled 12,613 barrels per day. This increase was attributable to an ongoing development drilling program during 2006 at the Seal field in Alberta. Light oil production in the WCSB fell 21% to 443 barrels per day in 2006 mostly due to less condensate produced at the Rimbey gas field in Alberta. Synthetic oil production at Syncrude increased 10% in 2006 and was 11,701 barrels per day. A third coker unit was started up during 2006, and the new unit permits a larger volume of bitumen to be processed at the plant. The new coker experienced various start up issues, but was operating near capacity at year-end 2006. All oil production in Malaysia during 2006 came from the West Patricia and adjoining Congkak fields in Block SK 309 offshore Sarawak. Net oil production from Malaysia was 11,298 barrels per day in 2006, 16% lower than in 2005 as the production sharing contract allocates a smaller portion of gross production to the Company's account in both a higher price environment and as prior costs are recovered. Gross production volumes at the Malaysian fields fell only 5% in 2006. Oil production offshore the United Kingdom fell 11% to 7,146 barrels per day. The most significant U.K. decline in 2006 occurred at the Schiehallion field and was primarily caused by a fire at the facilities used by this field. Total net oil produced at Block 16 in Ecuador was 8,608 barrels per day in

2006, a 9% increase from 2005 as a development drilling campaign continued in 2006. Oil sales volumes in Ecuador significantly exceeded production in 2006 due to selling 853,000 barrels of oil in settlement of a dispute with partners over 2004 oil production that was originally withheld from the Company.

Worldwide sales of natural gas were 61.1 million cubic feet (MMCF) per day in 2007, 75.3 million in 2006 and 90.2 million in 2005. Natural gas sales 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 gas volumes sold from two oil fields in the North Sea.

Sales of natural gas in the United States were 56.8 MMCF per day in 2006, down 19% from 2005. The reduced U.S. natural gas sales volume in 2006 was attributable to a combination of lower volumes produced onshore south Louisiana due to field decline and no volumes produced in 2006 at Gulf of Mexico continental shelf fields that were sold in mid-2005. In the Gulf of Mexico, production at a new field that came onstream in 2006 served to essentially offset lower volumes at other deepwater Gulf of Mexico fields. U.S. natural gas sales volumes in 2006 were virtually unaffected by downtime for tropical storms and hurricanes, while volumes in 2005 were adversely affected by downtime associated with Hurricanes Katrina and Rita. Natural gas sales volumes in Canada of 9.8 MMCF per day in 2006 were 6% lower than 2005, mostly caused by normal field decline in the Rimbey area. Natural gas sales volumes in the U.K. in 2006 were 8.7 MMCF per day, 8% lower than in 2005. The 2006 decline for natural gas sales volumes in the U.K. was wholly attributable to make-up gas volumes sold in 2005 at an offshore field in order to balance under-sold production in earlier years. Excluding the make-up volumes in 2005, U.K. natural gas sales volumes in 2006 would have exceeded 2005 amounts.

Worldwide crude oil sales prices have risen in each of the last two years due to the combination of a strong world economy, real and perceived instability in worldwide crude oil production levels, and effective production output controls by OPEC producers. The Company’s average realized sales price across all of its oil production 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, up 14% from 2006. The average sales price for heavy oil produced in Canada 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, 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 just completed 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 and its partners in Block 16 intend to initiate arbitration proceedings claiming that the government does not have the right under the contract to change this sharing arrangement.

The Company realized an average per barrel sales price of $51.62 for crude oil and condensate in 2006, up 14% from the 2005 average of $45.25 per barrel. The average realized oil sales price in 2006 in the U.S. was up 21% at $57.30 per barrel. The average sales price of Canadian heavy oil was $25.87 per barrel, also a 21% increase compared to 2005. Realized average prices per barrel for Hibernia and Terra Nova oil sales in 2006 were $63.48 and $59.79, respectively, with each up about 20% from 2005 averages. Synthetic oil production was sold at $63.23 per barrel in 2006, up 9% from 2005 prices. The realized sales price for synthetic oil did not rise as much as other oil because of higher volumes of similar crudes available in the market for which demand did not keep pace with the growth. Average crude oil prices in Malaysia of $51.78 per barrel in 2006 were 12% higher than 2005, while U.K. prices in 2006 rose 22% to $64.30 per barrel. The average oil price realized in Ecuador of $33.79 per barrel rose only 4% from 2005 as the Ecuadorian government passed a revenue sharing law that became effective in April 2006, whereby the government received a revenue-share of 50% for realized prices exceeding a benchmark price that escalates with the inflation rate.

The Company’s North American natural gas sale prices in 2007 and 2006 did not rise in tandem with higher crude oil prices. The Company’s average realized North American natural gas sales prices fell 5% in 2007 to $7.19 per thousand cubic feet (MCF). In the U.K., the average 2007 natural gas price rose 3% to $7.54 per MCF.

North American gas sales prices averaged $7.57 per MCF in 2006, down 10% from the 2005 average. The sales price for natural gas in the U.K. was up 27% and averaged $7.34 per MCF.

Based on 2007 sales volumes and deducting taxes at marginal rates, each $1.00 per barrel and $0.10 per MCF fluctuation in prices would have affected earnings from exploration and production operations by $19.8 million and $1.4 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 $463.0 million in 2007, $383.2 million in 2006 and $302.6 million in 2005. These amounts are shown by major operating area on pages F-38 and F-39 of this Form 10-K report. Costs per equivalent barrel during the last three years are shown in the following table.

Dollars per equivalent barrel)	2007	2006	2005
United States	**$ 10.75**	7.10	5.17
Canada			
Excluding synthetic oil	**8.77**	9.36	4.40
Synthetic oil	**30.56**	28.23	24.35
United Kingdom	**10.34**	6.19	5.10
Malaysia	**12.60**	7.46	6.98
Ecuador	**10.60**	7.85	7.07
Worldwide – excluding synthetic oil	**10.29**	7.91	5.31

Production cost per equivalent barrel increased in the U.S. in 2007 mostly due to higher workover and field repairs and lower production volumes. The rate per equivalent barrel in 2006 was up from 2005 mostly due to higher insurance costs coupled with lower overall production. The per-unit costs for Canadian conventional oil and gas operations, excluding Syncrude was lower in 2007 than 2006 primarily due to higher production levels and lower repair costs at Terra Nova in 2007. The field was shut-in for major repairs for six months in 2006. Canadian costs excluding Syncrude rose significantly in 2006 due to lower production volumes and higher repair costs at Terra Nova while off-line for major repairs, plus a higher mix of more costly heavy oil production versus lighter oils. Higher production costs per barrel for Canadian synthetic oil operations in 2007 were primarily due to a higher net profit royalty rate and a higher foreign exchange rate. In 2006 higher costs for synthetic operations were mostly attributable to higher coker repair costs and higher compensation 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 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. Higher 2006 costs per barrel produced in the U.K. and Malaysia were mostly attributable to higher facility maintenance costs. Higher per-unit operating costs in Ecuador in 2007 were primarily caused by increasing water handling costs as Block 16 wells mature. Higher per-unit operating costs in Ecuador in 2006 compared to 2005 were mostly attributable to higher field operating costs in the Amazon region where Block 16 is located.

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-38 and F-39 on this Form 10-K report. Certain of the expenses are included in the capital expenditures total for exploration and production activities.

(Millions of dollars)	2007	2006	2005
Dry holes	**$ 67.1**	111.0	126.0
Geological and geophysical	**67.7**	73.1	73.4
Other	**35.1**	12.6	10.2
	169.9	196.7	209.6
Undeveloped lease amortization	**33.2**	22.5	22.8
Total exploration expenses	**$ 203.1**	219.2	232.4

Dry holes expense was $43.9 million less in 2007 than 2006 primarily due to a lower level of exploration drilling activity in 2007. With mostly new E&P management in 2007, much of the year was spent reevaluating exploration drilling prospects on a worldwide basis. Dry holes expense was $15.0 million lower in 2006 than 2005 mostly due to less unsuccessful wildcat drilling in the Republic of Congo, but partially offset by higher unsuccessful drilling costs in the Gulf of Mexico. Geological and geophysical (G&G) expenses were $5.4 million less in 2007 than 2006 primarily due to lower spending on 3-D seismic in Blocks SK 311 and H, and lower geophysical analyses on PM Blocks 311/312, all in Malaysia. 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 Congo. G&G expenses in 2006 were about level with 2005 as higher costs in the Gulf of Mexico were essentially offset by lower spending offshore eastern Canada. Other exploration expenses in 2007 were $22.5 million higher than 2006 mostly due to a $21.9 million settlement of unfulfilled work commitments on two expiring Scotian Shelf leases. Other exploration expenses in 2006 were $2.4 million higher than in 2005 mostly due to higher administrative costs for international exploration activities. Undeveloped leasehold amortization expense rose $10.7 million in 2007 compared to 2006 primarily due to amortization of land acquisitions at the Tupper property in northeast British Columbia. Undeveloped leasehold amortization expense in 2006 was virtually flat with 2005.

A $2.6 million charge for asset impairment in 2007 was taken to write-down an unused E&P administrative office to its estimated fair value.

Costs of $1.9 million and $18.8 million were incurred in 2006 and 2005, respectively, in the Company’s exploration and production operations for uninsured costs to repair damages and to recognize associated higher insurance costs caused by hurricanes in the Gulf of Mexico. These costs were related to the effects of Hurricanes Katrina and Rita, and also included in 2005 discretionary assistance to employees in the New Orleans area after Hurricane Katrina.

Depreciation, depletion and amortization expense related to exploration and production operations totaled $376.8 million in 2007, $297.0 million in 2006 and $319.1 million in 2005. 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 $22.1 million reduction in 2006 compared to 2005 was attributable to lower oil and natural gas sales volumes, partially offset by generally higher per-barrel capital amortization caused by higher costs for development operations and negative U.S. reserve revisions. 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 $16.1 million in 2007, $10.8 million in 2006 and $9.6 million in 2005 for accretion on discounted abandonment liabilities. Because the abandonment liabilities are 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 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 additional development wells drilled in the Kikeh field in 2007. The higher accretion costs incurred in 2006 were also mostly associated with development wells drilled at the Kikeh field in the prior year.

The effective income tax rate for exploration and production operations was 34.6% in 2007, 36.1% in 2006 and 39.1% in 2005. Both 2007 and 2006 included net tax benefits due to enacted changes in foreign tax rates. Canada lowered federal tax rates in both years and in 2006 the Canadian provinces of Alberta and Saskatchewan also lowered 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. A U.K. tax rate increase from 40% to 50% on oil and gas profits in 2006 increased taxes in the prior year by $17.8 million. The effective tax rate in 2007 was slightly below the U.S. statutory tax rate of 35% primarily due to the enacted Canadian tax rate reduction during the year. The 2007 effective tax rate was lower than in 2006 mostly due to the charge in 2006 related to the U.K. tax rate increase. A benefit for a charitable building donation based on fair value reduced U.S. taxes by $4.4 million in 2007. Also in 2007, the Company incurred lower exploration and other expenses in tax jurisdictions where tax relief is currently not available. These tax jurisdictions with no current tax benefit on expenses primarily include non-revenue generating areas in Malaysia, the Republic of Congo and Indonesia. Each main exploration area in Malaysia is currently ring-fenced and 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. Although the 2006 effective tax rate was only slightly higher than the U.S. statutory tax rate of 35%, the annual rate was lower than in 2005 mostly due to net benefits from the aforementioned tax rate changes. The effective tax rate in 2005 was higher than the average U.S. statutory rate due to unrecognized income tax benefits on certain exploration and other expenses in Malaysia and the Republic of Congo.

At December 31, 2007, approximately 39% of the Company's U.S. proved oil reserves and 38% 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, 42% of both oil and natural gas reserves of 61.2 million barrels and 107.1 billion cubic feet, respectively, at year-end 2007 for the Kikeh field are undeveloped pending completion of facilities and continued development drilling, and 100% of the 14.8 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 317.0 billion cubic feet of undeveloped natural gas reserves at various fields offshore Sarawak at year-end 2007, pending completion of development drilling and facilities. First gas production at the Kikeh field is scheduled for the second half of 2008 and at Sarawak fields in early 2009. On a worldwide basis, the Company spent approximately $769 million in 2007, $560 million in 2006 and $378 million in 2005 to develop proved reserves. The Company expects to spend about $1,061 million in 2008, $495 million in 2009 and $474 million in 2010 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 $205.7 million in 2007, after earning $110.6 million in 2006 and $131.6 million in 2005. 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, $67.1 million in 2006 and $28.7 million in 2005. The Meraux, Louisiana refinery significantly increased crude oil throughputs in 2007 compared to 2006, which 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 16% decline in earnings in 2006 compared to 2005 was primarily due to hurricane related after-tax costs of $67.1 million and lower crude oil throughput volumes at the Meraux, Louisiana refinery. In late August 2005, the Meraux refinery experienced severe flooding and wind damage associated with Hurricane Katrina and was shut down from late August 2005 through mid-2006. The hurricane related costs in 2006 were partially offset by stronger refining margins generated by the Superior, Wisconsin refinery and continued growth in the Company's North American retail gasoline marketing activities.

The Company's North American R&M operations generated earnings of $230.4 million in 2007, $77.5 million in 2006 and $91.1 million in 2005. North American operations include refining activities in the United States and marketing activities in the United States and Canada. The 2006 and 2005 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, $107.3 million in 2006 and $46.3 million in 2005. The 2007 hurricane costs were caused by a downward adjustment of expected insurance recoveries based on the latest loss limits published by the Company's primary insurer. The Meraux refinery throughput volumes of crude oil and other feedstocks averaged 112,840 barrels per day in 2007, 57,198 barrels per day in 2006 and 75,443 barrels per day in 2005. 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 generated strong earnings in 2007 and 2006 as a result of steady operations and the continued strength of industry refining margins in North America. The operating results for the Company's North American retail gasoline stations were lower in 2007 compared to the prior year as 55 underperforming stores were closed during the just completed year, including 47 in the U.S. and all eight stations in Canada. The Company recorded an impairment charge 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 33 new retail stations were opened in 2007, including 31 in the parking lots of Wal-Mart Supercenters and two at other locations. Average fuel sales per station increased again in 2007, the 10th straight year of improvements. The Company's operating results in 2006 for North American retail operations were similar to 2005, and 2006 was highlighted by higher average fuel and non-fuel sales volumes compared to 2005 as well as continued additions to the number of stations in operation. Retail fuel sales volumes increased 22% in 2006 compared to 2005. The Company added 123 Murphy USA fueling stations in 2006, a 14% increase in the number of sites at year-end 2006 compared to 2005.

Unit margins (sales realization less costs of crude and other feedstocks, transportation to point of sale and refinery operating and depreciation expenses) averaged $4.28 per barrel in North America in 2007, $3.48 in 2006 and $2.96 in 2005. North American refined product sales volumes increased 19% to a record 416,668 barrels per day in 2007, following a 9% increase to 350,601 barrels per day in 2006. The Company's U.S. retail gasoline stations continued to increase per site fuel sales volumes with a 4% increase in the average monthly fuel sales volume per station in 2007 following a 6% increase in 2006.

Operations in the United Kingdom reported a loss of $24.7 million in 2007 compared to earnings of $33.1 million in 2006 and $40.5 million in 2005. On December 1, 2007, the Company acquired the remaining 70% of the Milford Haven, Wales refinery that it did not already own. In association with this acquisition, the Company built a significant additional layer of crude oil and refined products inventory. The 2007 loss included 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 last-in-first-out (LIFO) inventory accounting policy, inventory volume increases are priced at the first purchase prices during the year, and the prices of crude 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. After the LIFO charge, the average go-forward carrying value for these additional inventories in the U.K. has been reduced 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. The decrease in 2006 U.K. earnings compared to 2005 was due primarily to lower refinery margins as a result of higher operating and transportation costs in 2006 and nonrecurring credits in 2005 for property tax rebates and insurance settlements. The decline in refinery earnings in 2006 was partially offset by stronger marketing margins and higher marketing sales volumes as a result of the contribution from 68 retail sites acquired in 2005.

Unit margins in the United Kingdom averaged $0.22 per barrel in 2007, $6.39 per barrel in 2006 and $6.36 per barrel in 2005. Overall sales of refined products in the U.K. increased 19% in 2007, following a decline of 2% in 2006. The 2007 sales increase was mostly attributable to additional quantities of refined products produced after the Milford Haven acquisition. The decline in 2006 sales volumes was primarily due to lower demand for refined products based on higher average sales prices.

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 $96.3 million in 2007, $82.7 million in 2006 and $35.5 million in 2005. 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 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 Wal-Mart 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 $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.

Net corporate costs were $47.2 million higher in 2006 than 2005 primarily due to a $25.1 million after-tax cost recorded in 2006 for the El Dorado Promise, unfavorable foreign exchange impacts and lower income tax benefits in 2006. The U.S. dollar weakened by 14% against the British pound sterling and 12% against the Euro during 2006, but the exchange rate against the Canadian dollar was not significantly different in 2006 compared to 2005. The after-tax effect of the weaker U.S. dollar in 2006 was a charge of $7.9 million, while the foreign exchange effect on 2005 was insignificant. The 2005 corporate results included $9.7 million of income tax benefits due to refund and settlement of prior year U.S. income tax matters. Interest income was higher by $4.9 million in 2006 mostly due to interest collected on favorable settlements of prior-year lawsuits and other disagreements with partners on E&P projects in Ecuador and western Canada. Administrative expenses in the corporate area were $40.2 million higher in 2006 mostly due to the educational assistance commitment, plus higher costs associated with initial recognition of the grant-date fair value of stock options beginning in 2006. These higher administrative expenses were partially offset in 2006 by lower other incentive compensation costs. Interest expense was $5.2 million higher in 2006 mostly due to higher average outstanding borrowings under credit facilities. The portion of interest capitalized to development projects increased by $4.5 million in 2006 due mostly to higher capital spending on Kikeh field development, offshore Sabah, Malaysia, and for field development in the Gulf of Mexico, partially offset by lower interest capitalized on the expansion at Syncrude.

Capital Expenditures

As shown in the selected financial data on page 13 of this Form 10-K report, capital expenditures, including exploration expenditures, were $2,357.3 million in 2007 compared to $1,262.5 million in 2006 and $1,329.8 million in 2005. These amounts included $169.9 million, $196.7 million and $209.6 million, respectively, in 2007, 2006 and 2005 for exploration costs that were expensed. Capital expenditures for exploration and production activities totaled $1,780.7 million in 2007, $1,082.8 million in 2006 and $1,092.0 million in 2005, representing 76%, 86% and 82%, respectively, of the Company’s total capital expenditures for these years. E&P capital expenditures in 2007 included $422.6 million for acquisition of undeveloped leases, primarily in the Tupper area of northeastern British Columbia, $205.7 million for exploration activities, and $1,152.4 million for development projects. Development expenditures included $183.5 million for deepwater fields in the Gulf of Mexico; $512.2 million for the Kikeh field in Malaysia; $69.4 million for natural gas and other development activities in SK Blocks 309/311; $23.6 million for synthetic oil operations at the Syncrude project in Canada; $96.9 million for western Canada heavy oil and natural gas projects; $129.3 million for development of the Azurite field in the Republic of Congo; $26.5 million for the Terra Nova and Hibernia oil fields, offshore Newfoundland; $31.2 million for fields in the U.K. North Sea; and $40.1 million for development of Block 16 in Ecuador. Exploration and production capital expenditures are shown by major operating area on page F-37 of this Form 10-K report.

Refining and marketing capital expenditures totaled $572.5 million in 2007, $173.4 million in 2006 and $202.4 million in 2005. These amounts represented 24%, 14% and 15% of capital expenditures of the Company in 2007, 2006 and 2005, respectively. Refining capital spending was $330.0 million in 2007 compared to $57.3 million in 2006 and $34.1 million in 2005. 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, Louisiana refinery. The bulk of the refining capital in 2006 was spent at the Meraux, Louisiana refinery where numerous capital improvements were completed while the plant was shut-down for repairs following Hurricane Katrina. Marketing expenditures amounted to $242.5 million in 2007, $116.1 million in 2006 and $168.2 million in 2005. The capital spending in 2007 was mostly attributable to acquisition of land underlying retail gasoline stations located at Wal-Mart Supercenters. The majority of marketing expenditures in 2006 and 2005 was related to construction of retail gasoline stations at Wal-Mart Supercenters in the U.S. The Company opened 33 new stations within this network in 2007, after adding 123 in 2006 and 112 in 2005. In 2005, the Company also purchased 68 retail fueling stations in the U.K., thereby expanding its company-owned retail station count in that country by 70%.

Cash Flows

Cash provided by operating activities was $1,740.4 million in 2007, $975.5 million in 2006 and $1,248.9 million in 2005. 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 depreciation, impairment and deferred tax expenses, and a reduction of noncash operating working capital in 2007 versus an increase in 2006. Cash provided by operating activities in 2006 was about $273 million lower than in 2005 and was unfavorably affected by higher spending in 2006 for inventories, prepaid insurance, and repair costs at the Meraux refinery. In addition, 2006 cash provided by operating activities 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 in 2005 included $8.6 million from discontinued operations. Cash provided by operating activities was reduced by expenditures for abandonment of oil and gas properties totaling $13.0 million in 2007, $3.3 million in 2006 and $8.3 million in 2005.

Cash proceeds from property sales were $21.6 million in 2007, $23.8 million in 2006 and $172.7 million in 2005. The sales proceeds in 2007 and 2006 primarily related to sales of various properties, real estate and aircraft. The 2005 sales proceeds were mostly attributable to sale of most oil and gas properties on the continental shelf of the Gulf of Mexico; the Company retained its deepwater Gulf of Mexico properties. 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 certain income tax benefits on stock options classified as financing activities, amounted to $72.4 million in 2007, $36.6 million in 2006 and $26.5 million in 2005. Maturity of U.S. government securities provided cash of $17.9 million in 2005.

During 2007, the Company spent $348.3 million to acquire the remaining 70% interest in the Milford Haven, Wales refinery and associated inventory. Property additions and dry hole costs used cash of $1,949.2 million in 2007, $1,191.7 million in 2006 and $1,246.2 million in 2005. Higher amounts spent in 2007 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 gasoline stations at Wal-Mart stores and surrounding the Meraux refinery. Lower amounts used in 2006 compared to 2005 were mostly attributable to acquisition in 2005 of 68 retail fueling stations by the U.K. marketing operations. For E&P operations, higher costs in 2006 for development drilling at the Kikeh field in Block K Malaysia and exploration drilling in the Gulf of Mexico were mostly offset by lower costs during the year for Syncrude expansion and exploration drilling in the Republic of Congo. Cash of $14.6 million in 2007, $12.8 million in 2006 and $23.7 million in 2005 was used to fund turnarounds of refineries and at Syncrude. A complete scheduled turnaround occurred at the Milford Haven, Wales refinery in 2005. The Company repaid debt of $50.6 million in 2005 using a combination of internal cash flow and proceeds from sale of assets. Cash used for dividends to stockholders was $127.4 million in 2007, $98.2 million in 2006 and $83.2 million in 2005. The Company raised its annualized dividend rate from $0.60 per share to $0.75 per share beginning in the third quarter of 2007. The Company had previously increased the annualized dividend rate from $0.45 per share to $0.60 per share beginning in the third quarter of 2006.

Financial Condition

Year-end working capital (total current assets less total current liabilities) totaled $777.5 million in 2007, $796.0 million in 2006 and $551.9 million in 2005. 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 $709.7 million below fair value at December 31, 2007. Cash and cash equivalents at the end of 2007 totaled $673.7 million compared to $543.4 million at year-end 2006 and $585.3 million at year-end 2005.

The long-term portion of debt increased by $675.9 million during 2007 and totaled $1,516.2 million at year-end 2007, which represented 23.0% of total capital employed. The increase in long-term debt in 2007 was necessitated by the Company's funding of significant ongoing oil and natural gas development projects, with the largest of these being the Kikeh field in Malaysia. Long-term debt at year-end 2007 included $3.1 million of nonrecourse debt associated with the Hibernia oil field development; all the nonrecourse debt is scheduled to be repaid by 2009. Long-term debt increased by $230.7 million in 2006 as the Company utilized its borrowing capacity to fund its development capital program. Stockholders' equity was $5.07 billion at the end of 2007 compared to $4.12 billion a year ago and $3.52 billion at the end of 2005. A summary of transactions in stockholders' equity accounts is presented on page F-6 of this Form 10-K report.

Other significant changes in Murphy's year-end 2007 balance sheet compared to 2006 included a $425.5 million increase in accounts receivable, which was caused by sales of crude oil and refined petroleum products at higher average prices near the end of 2007 compared to 2006. Inventory values were $215.6 million higher at year-end 2007 than in 2006 mostly because of more crude oil and refined product volumes held in storage at the Milford Haven refinery following the purchase of the remaining 70% on December 1, 2007, plus a higher level of unsold crude oil production held in inventory caused mostly by timing of sales liftings at the Kikeh field. Prepaid expenses decreased $57.1 million in 2007 primarily due to lower prepaid Canadian income taxes. Short-term deferred income tax assets increased $65.4 million at year-end 2007 due mostly to changes in the components of temporary differences in the U.K. following the Milford Haven refinery acquisition. Net property, plant and equipment increased by $2,003.5 million in 2007 as a significant level of property additions during the year exceeded the additional depreciation and amortization expensed. Goodwill increased $7.4 million due to a stronger Canadian dollar exchange rate versus the U.S. dollar. Deferred charges and other assets increased $262.1 million and deferred credits and other liabilities increased by $236.4 million in 2007 due to essentially offsetting recorded assets and liabilities associated with significant E&P development projects. Current maturities of long-term debt were not materially different at year-end 2007 compared to 2006. Notes payable increased $4.9 million in 2007 due to short-term borrowings by the Company's consolidated subsidiary, Berkana Energy Corp. Accounts payable rose by $653.8 million at year-end 2007 compared to 2006 mostly due to higher amounts owed for crude oil and refined product purchases and for capital expenditures. Income taxes payable increased $45.8 million at year-end 2007 due to higher taxes owed in the current year on income in the U.S., Canada, Malaysia and the U.K. Other taxes payable increased $48.4 million mostly due to higher sales, use and excise taxes owed at year-end 2007 compared to 2006. Other accrued liabilities increased by $44.6 million in 2007 mostly due to higher amounts payable into the Company's domestic retirement plans in 2008. Deferred income tax liabilities increased $295.6 million in 2007 due mostly to higher liabilities for future taxes in the U.K., U.S., Canada and Malaysia. The liability associated with future asset retirement obligations increased by $98.2 million mostly due to development wells drilled during 2007 offshore Malaysia and higher estimated future costs for abandonment of existing wells in the Gulf of Mexico. 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 acquired 80% of Berkana in December 2006 in exchange for a non-cash contribution of the Company's Rimbey property in Alberta. The Company sold its entire investment in Berkana shares in January 2008.

Murphy had commitments for future capital projects of approximately $2,129.0 million at December 31, 2007, including $84.0 million for lease acquisitions in a recent Gulf of Mexico sale, $71.4 million for costs to develop deepwater Gulf of Mexico fields, $850.3 million for field development and future work commitments in Malaysia, $561.2 million for field development and a work commitment in the Republic of Congo, and $157.1 million for purchases of land underlying certain U.S. retail gasoline stations. A partial sale of the Company's working interest in the Republic of Congo was pending government approval at December 31, 2007. Once approved, the Company's commitment for field development will be reduced by approximately $178.0 million.

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, and maintains lines of credit with banks and borrows as necessary to meet spending requirements. At December 31, 2007, the Company had access to long-term revolving credit facilities in the amount of $1.962 billion. A total of $718.5 million was borrowed under these revolving credit facilities at year-end 2007. These credit facilities increased significantly and were renewed for one additional year during 2007. The most restrictive covenants under these existing credit facilities limit the Company's long-term debt to capital ratio (as defined in the agreements) to 60%. At December 31, 2007, the long-term debt to capital ratio was approximately 23.0%. At December 31, 2007, the Company had borrowed $197 million under uncommitted credit lines and had additional uncommitted amounts available of approximately US $440 million in a combination of U.S. and Canadian dollars. In addition, the Company has a shelf registration on file with the U.S. Securities and Exchange Commission that permits the offer and sale of up to $650 million in debt and/or equity securities. Current financing arrangements are set forth more fully in Note F to the consolidated financial statements. Based on its 2008 Budget, the Company anticipates utilizing a significant portion of its long-term borrowing capacity under existing credit facilities during the year to fund certain ongoing development projects. The level of additional borrowings are subject to change based on actual levels of cash flows and capital spending. At February 28, 2008, 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 14.5 to 1 in 2007, 16.1 to 1 in 2006 and 24.1 to 1 in 2005.

Environmental

Murphy and other companies in the oil and gas industry are subject to numerous federal, state, local and foreign laws and regulations. The most significant of those laws and the corresponding regulations affecting the Company'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 water discharges. They also generally require permits for new or modified operations. Many states and foreign countries where Murphy operates also have or are developing similar statutes and regulations governing air and water, which in some cases impose or could impose additional and more stringent requirements. Murphy is also subject to certain acts and regulations primarily governing remediation of wastes or oil spills.

CERCLA, commonly referred to as the Superfund Act, and comparable state statutes primarily address historic contamination and impose joint and several liability for cleanup of contaminated sites on owners and operators of the sites. As discussed below, Murphy is involved in a limited number of Superfund sites. CERCLA also requires reporting of releases to the environment of substances defined as hazardous.

RCRA and comparable state statutes govern the management and disposal of wastes, with the most stringent regulations applicable to treatment, storage or disposal of hazardous wastes. Under OPA90, owners and operators of tankers, owners and operators of onshore facilities and pipelines, and lessees or permittees of an area in which an offshore facility is located are liable for removal and cleanup costs of oil discharges into navigable waters of the United States.

The U.S. Environmental Protection Agency (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 the Company's 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. The Company's management is currently studying alternatives available for fully meeting this ULSD standard at Meraux and Superior.

The Energy Independence and Security Act was signed into law in December 2007. The 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.

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 that has been ratified by certain countries in which the Company operates or may operate in the future, with the United States being the primary country that has yet to ratify the agreement. The U.S. may ratify all or a portion of the agreement in the future. 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. The Company is unable to predict how final regulations associated with the agreement will impact its costs in future years, but it is reasonable to expect these regulations to increase its compliance costs to some degree.

The Company is also involved in personal injury and property damage claims, allegedly caused by exposure to or by the release or disposal of materials manufactured or used in the Company's operations.

The Company operates or has previously operated certain sites and facilities, including three refineries, five terminals, and approximately 116 service stations, for which known or potential obligations for environmental remediation exist. In addition the Company operates or has operated numerous oil and gas fields that may require some form of remediation.

Under the Company's accounting policies, an environmental liability is recorded when such an obligation is probable and the cost can be reasonably estimated. If there is a range of reasonably estimated costs, the most likely amount will be recorded, or if no amount is most likely, the minimum of the range is used. Recorded liabilities are reviewed quarterly. Actual cash expenditures often occur one or more years after a liability is recognized.

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.

The 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. Based on currently available information, the Company believes that it is a de minimis party as to ultimate responsibility at both 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 two 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 net income, financial condition or liquidity in a future period.

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, 2007.

The Company's refineries 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 hydrotreating catalysts); spent/used filter media; tank bottoms and API separator sludge; contaminated soils; laboratory and maintenance spent solvents; and various industrial debris. The costs of disposing of these substances are expensed as incurred and amounted to $3.9 million in 2007. In addition to these expenses, Murphy allocates a portion of its capital expenditure program to comply with environmental laws and regulations. Such capital expenditures were approximately $70.8 million in 2007 and are projected to be $172.8 million in 2008.

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. Because crude oil and natural gas sales prices have generally strengthened during the last several years, prices for oil field goods and services have risen (with certain of these price increases such as drilling rig day rates having been significant), and prices could continue to be adversely affected in the future. 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, although the Company anticipates escalation in prices for certain equipment and services as long as oil prices remain strong.

Accounting changes and recent accounting pronouncements – In September 2006, the Financial Accounting Standards Board (FASB) issued FSP AUG AIR-1, Accounting for Planned Major Maintenance Activities, which prohibited effective January 1, 2007 the use of the accrue-in-advance method of accounting for planned major maintenance activities as historically used by the Company. Accordingly, the Company has chosen to use the permitted deferral method of accounting for planned major maintenance activities such as refinery turnarounds beginning in 2007. Under the deferral method, the actual cost of each planned major maintenance activity is deferred and amortized through the next turnaround. All prior period financial statements have been adjusted to reflect the adoption of FSP AUG AIR-1 as if the deferral method was in effect in prior periods. A cumulative after-tax adjustment to increase Retained Earnings of $50.8 million was recorded as of January 1, 2005 to effect the adoption of FSP AUG AIR-1. Net income for 2006 and 2005 have been restated to reflect the earnings for the periods as if FSP AUG AIR-1 had been in effect during the periods. The effect for the years 2006 and 2005 was an increase to net income of $6.4 million ($.04 per diluted share) and $8.3 million ($.04 per diluted share), respectively. As presented on the consolidated balance sheet as of December 31, 2006, the previously reported liability for Accrued Major Repair Costs of $71.2 million has been removed and a noncurrent asset of $37.4 million, representing the unamortized deferred costs of planned major maintenance activities as of that date, has been added to Deferred Charges and Other Assets. In association with the adoption of FSP AUG AIR-1, the Company will present expenditures for major repairs as an investing activity in the Consolidated Statement of Cash Flows. Refer to Note P for further information.

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. 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 $4.3 million. Refer to Note K 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. 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 on January 1, 2007, the Company recognized a $0.7 million 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. See Note I for further information.

In September 2006, the U.S. Securities and Exchange Commission released Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements (SAB 108), which provides interpretive guidance on the SEC's views regarding the process of quantifying materiality of financial statement misstatements. SAB 108 was effective for fiscal years ending after November 15, 2006, with early application for the first interim period ending after November 15, 2006. The adoption of this standard at December 31, 2006 had no impact on the Company's financial statements.

In June 2006, the EITF finalized Issue 06-3, How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement. The Task Force reached a consensus that this EITF applied to any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but is not limited to sales, use, value added, and some excise taxes. The EITF concluded that the presentation of taxes within the scope of this issue may be either gross (included in revenues and costs) or net (excluded from revenues and costs) and is an accounting policy decision that should be disclosed by the Company. The Company excludes excise taxes collected on sales of refined products and remitted to governmental agencies from its revenues and costs of sales.

In March 2005, the EITF decided in Issue 04-6 that mining operations should account for post-production stripping costs as a variable production cost that should be considered a component of mineral inventory costs. The Company's synthetic oil operation at Syncrude is affected by this ruling, which was effective as of January 1, 2006 for the Company. The Company has determined that the level of bitumen inventory at Syncrude affected by this EITF consensus is immaterial and it has continued to expense post-production stripping costs as incurred.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. 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 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 does not expect the initial adoption of this statement to have a material impact on its 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 is effective January 1, 2008 for the Company. The Company is considering SFAS No. 159, and at this time the Company does not expect to elect the fair value option for any financial assets and financial liabilities.

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. This new guidance will be effective for the Company beginning in 2008, and will require 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 Company does not expect the adoption of this consensus to have a material impact on its financial statements.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51. 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. This statement is effective for the Company beginning January 1, 2009. 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.

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-35 and F-36 of the 2007 annual report. 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 reserve revision in Malaysia in 2006 was mostly due to extension of proved oil in the Kikeh reservoir. The U.S. oil reserve revision in 2005 was mostly due to poor well performance at one deepwater Gulf of Mexico field. Oil reserve revisions in 2005 in Canada, the U.K. and Ecuador were due to better field performance, while the Malaysia revision was caused by higher oil prices that reduce volumes allocable to the Company for cost recovery under production sharing contracts. 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.

- *Successful efforts accounting* – The Company utilizes the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration wells are expensed and can have a significant effect on net income. Successful exploration drilling costs, all development capital expenditures and asset retirement costs are capitalized and systematically charged to expense using the units of production method based on proved developed oil and natural gas reserves as estimated by the Company's engineers.

  In some cases, a determination of whether a drilled well has found proved reserves 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.

  Costs for one exploration well in progress at year-end 2007 amounted to $5.8 million. In January 2008, the well was determined to have successfully found hydrocarbon deposits and will be further evaluated for commerciality.

  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 2007 or 2005 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 could exceed its fair value. 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 could exceed its fair value. 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. Although the Company does not believe it had any significant properties with carrying values that were impaired at December 31, 2007, one or a combination of factors such as significantly lower future sales prices, significantly lower future production, significantly higher future costs, significantly 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 $23.28 per barrel at December 31, 2007. The Company and its partners in Block 16 intend to initiate 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 at December 31, 2007 amounted to $106.5 million.

- *Income taxes* – The Company is subject to income and other similar taxes in all areas in which it operates. When recording income tax expense, certain estimates are required because: (a) income tax returns are generally filed months after the close of its annual accounting period; (b) tax returns are subject to audit by taxing authorities and audits can often take years to complete and settle; and (c) future events often impact the timing of when income tax expenses and benefits are recognized by the Company. The Company has deferred tax assets mostly relating to basis differences for property, equipment and inventories, and dismantlements and retirement benefit plan liabilities. The Company routinely evaluates all deferred tax assets to determine the likelihood of their realization. A valuation allowance has been recognized for deferred tax assets related to basis differences for Blocks H, PM 311/312, P, L and M in Malaysia, exploration licenses in the Republic of Congo 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 higher bond yields during 2007, the Company has increased the primary U.S. plans' discount rate from 6.00% in 2007 to 6.50% in 2008 and beyond. Although the Company presently assumes a return on plan assets of 7.00% 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 2008 compared to 2007 as the effects from a growing employee base may not be fully offset by the effects of a higher discount rate. In 2007, the Company paid $12.2 million into various retirement plans and $3.5 million into postretirement plans. In 2008, the Company is expecting to fund payments of approximately $56.6 million into various retirement plans and $4.7 million for postretirement plans. The Company could be required to make additional and more significant funding payments to retirement plans in future years. Future required payments and the amount of liabilities recorded on the balance sheet associated with the plans could be unfavorably affected if the discount rate declines, the actual return on plan assets falls below the assumed 7.0%, 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 2008 annual retirement and postretirement expenses by $3.8 million and $0.5 million, respectively, and a 0.5% decline in the assumed rate of return on plan assets would increase 2008 retirement expense by $1.8 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 2007 under such contractual obligations and arrangements are shown below.

	Amount of Obligation				
(Millions of dollars)	**Total**	**2008**	**2009-2010**	**2011-2012**	**After 2012**
Total debt including current maturities	$1,521.4	5.2	3.1	1,265.0	248.1
Operating leases	895.3	93.3	187.5	173.8	440.7
Purchase obligations	3,505.4	1,840.9	1,178.6	361.0	124.9
Other long-term liabilities	626.9	90.3	69.7	53.3	413.6
Total	$6,549.0	2,029.7	1,438.9	1,853.1	1,227.3

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 above table.

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, 2007 that expire in future periods is shown below.

	Amount of Commitment				
(Millions of dollars)	**Total**	**2008**	**2009-2010**	**2011-2012**	**After 2012**
Financial guarantees	$ 8.5	—	—	—	8.5
Letters of credit	292.5	290.5	—	—	2.0
Total	$301.0	290.5	—	—	10.5

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 2007 includes an operating lease of the Kikeh floating, production, storage and offloading vessel (FPSO), an oil and natural gas processing contract and a hydrogen purchase contract. The Kikeh FPSO lease calls for future monthly net lease payments over the next eight years. The processing contract provides crude oil and natural gas processing capacity for oil and natural gas production from the Medusa field in the Gulf of Mexico. Under the contract, the Company pays a specified amount per barrel of oil equivalent for processing its oil and natural gas through the facility. If actual oil and natural gas production processed through the facility through 2009 is less than a specified quantity, the Company must make additional quarterly payments up to an agreed minimum level that varies over time. Through 2007, actual production from the Medusa field has exceeded the contractual minimum volumes. The Company has a contract to purchase hydrogen for the Meraux refinery through 2021. The contract requires a monthly minimum base facility charge whether or not any hydrogen is purchased. Payments under both these agreements are recorded as operating expenses when paid. 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. Due to the volatility of worldwide crude oil and North American natural gas prices, especially in light of a potentially weakening world economy in early 2008, routine monitoring of spending plans is required.

The Company's capital expenditure budget for 2008 was prepared during the fall of 2007 and based on this budget capital expenditures are expected to increase over 2007. Capital expenditures in 2008 are projected to total $2.8 billion. Of this amount, $2.1 billion or about 77%, is allocated for the exploration and production program. Geographically, E&P capital is spread approximately as follows: 14% for the United States, 49% for Malaysia, 21% for Canada and 16% 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 the Kikeh field in Block K, where continued drilling will lead to additional wells being brought on production during 2008, and for development of natural gas fields in Blocks SK 309 and 311 offshore Sarawak where first production is anticipated in 2009. The bulk of Canadian spending in 2008 will relate to natural gas development at the Tupper field. Spending in the Republic of Congo includes continuing development costs for the Azurite discovery offshore. Refining and marketing expenditures in 2008 should be about $650 million of which about 80% is allocated for the U.S., including funds for further purchases of land underlying stations at Wal-Mart Supercenters and construction of additional retail gasoline stations. Capital and other expenditures are routinely reviewed and planned capital expenditures may be adjusted to reflect differences between budgeted and actual cash flow during 2008. Capital expenditures may also be affected by asset purchases, which often are not anticipated at the time the Budget is prepared.

The Company currently expects to fund its capital budget in 2008 using a combination of operating cash flow and available credit facilities. The Company forecasts an increase in long-term debt of approximately $760 million in 2008. This forecast could change based on actual cash flow generated from operations and actual levels of capital spending. For example, a significant reduction in sales prices for crude oil and natural gas, without a corresponding decrease in capital spending, could cause the Company’s long-term debt to rise by more than the current forecast. Oil prices weakened slightly in January 2008 compared to prices experienced near the end of 2007, but in February oil prices rebounded to higher levels. These oil prices remained above the prices used in the Company’s 2008 budget. Through early 2008, margins of the Company’s refining and marketing operations were below amounts included in the Company’s 2008 budget.

The Company currently expects production in 2008 to average about 135,000 barrels of oil equivalent per day. A key assumption in projecting the level of 2008 Company production is the anticipated start-up of natural gas production from Tupper in western Canada and offshore Malaysia. Oil production will continue to be ramped up at the Kikeh field throughout 2008. In addition, continued reliability of facilities at significant non-operated fields such as Syncrude, Hibernia and Terra Nova are necessary to achieve the anticipated 2008 production levels.

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 offsetting short-term derivative instruments at December 31, 2007 for a notional amount of 403,000 barrels of oil that are intended to manage the purchase price of certain Meraux refinery crude oil. These contracts were marked to market at year-end 2007 with a net charge of $40 thousand. A 10% increase or decrease in the price of crude oil would have had no impact on pretax income.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages F-1 through F-42, 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 the Company’s evaluation as of the end of the period covered by the filing of this Annual Report on Form 10-K, 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) are 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. Management’s evaluation of the effectiveness of our internal control over financial reporting excluded internal control for most of the remaining 70% interest of Milford Haven refinery, which we acquired on December 1, 2007. Controls excluded from management’s assessment related to Milford Haven balances at December 31, 2007 were approximately $404 million of assets, $15 million of liabilities, and $39 million of operating expenses and other income that occurred after the Milford Haven acquisition date. We plan to fully integrate the Milford Haven refinery into our assessment of internal control over financial reporting in 2008. Based on our evaluation, management has concluded that our internal control over financial reporting was effective as of December 31, 2007. 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, 2007 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 2007 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. OTHER INFORMATION

None

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Certain information regarding executive officers of the Company is included on page 10 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 14, 2008 under the captions "Election of Directors" and "Committees."

Murphy Oil has adopted a Code of Ethical Conduct for Executive Management, which can be found under the Corporate Governance and Responsibility tab at www.murphyoilcorp.com. Stockholders may also obtain free of charge a copy of the Code of Ethical Conduct for Executive Management by writing to the Company's Secretary at P.O. Box 7000, El Dorado, AR 71731-7000. Any future amendments to or waivers of the Company's Code of Ethical Conduct for Executive Management will be posted on the Company's 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 14, 2008 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 14, 2008 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 14, 2008 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 14, 2008 under the caption "Audit Committee Report."

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PART VI

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.
Report of Management – Consolidated Financial Statements	F-1
Report of Independent Registered Public Accounting Firm	F-1
Report of Management – Internal Control Over Financial Reporting	F-2
Report of Independent Registered Public Accounting Firm	F-2
Consolidated Statements of Income	F-3
Consolidated Balance Sheets	F-4
Consolidated Statements of Cash Flows	F-5
Consolidated Statements of Stockholders' Equity	F-6
Consolidated Statements of Comprehensive Income	F-7
Notes to Consolidated Financial Statements	F-8
Supplemental Oil and Gas Information (unaudited)	F-34
Supplemental Quarterly Information (unaudited)	F-42

2. Financial Statement Schedules

Schedule II – Valuation Accounts and Reserves	F-43

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.

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Exhibit No.		Incorporated by Reference to
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 February 7, 2007	Exhibit 3.2 of Murphy's Form 8-K filed February 12, 2007
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	Exhibit 4.1 of Murphy's Form 8-K report filed May 3, 2002 under the Securities Exchange Act of 1934
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	Stock Plan for Non-Employee Directors, as approved by shareholders on May 14, 2003	Exhibit 10.4 of Murphy's Form 10-K report for the year ended December 31, 2003
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

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Exhibit No.		Incorporated by Reference to
*12.1	Computation of Ratio of Earnings to Fixed Charges	
*13	2007 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 [1] 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 performanced-based employee restricted stock unit grant agreement	Exhibit 99.2 of Murphy's Form 10-K report for the year ended December 31, 2006
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

1 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	CLAIBORNE P. DEMING Claiborne P. Deming, President	Date:	February 29, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 29, 2008 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
CLAIBORNE P. DEMING Claiborne P. Deming, 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
ROBERT A. HERMES Robert A. Hermes, Director	CAROLINE G. THEUS Caroline G. Theus, Director
JAMES V. KELLEY James V. Kelley, Director	KEVIN G. FITZGERALD Kevin G. Fitzgerald, Senior Vice President and Chief Financial Officer (Principal Financial Officer)
R. MADISON MURPHY R. Madison Murphy, Director	JOHN W. ECKART John W. Eckart, Vice President and Controller (Principal Accounting Officer)

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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, 2007 and 2006, 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, 2007. 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, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007, 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 A to the consolidated financial statements, effective January 1, 2006, the Company changed its method of accounting for share-based payments and 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 planned major maintenance activities, 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, 2007, 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 29, 2008 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Houston, Texas
February 29, 2008

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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. The Company acquired the remaining 70% interest of the Milford Haven refinery on December 1, 2007, and management excluded from our assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2007, Milford Haven refinery's internal control over financial reporting associated with assets of approximately $404 million, liabilities of approximately $15 million, and operating expenses and other income of approximately $39 million included in the consolidated financial statements of Murphy Oil Corporation as of and for the year ended December 31, 2007. Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2007.

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, 2007, 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, 2007, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Murphy Oil Corporation acquired the remaining 70% interest of the Milford Haven refinery on December 1, 2007, and management excluded from its assessment of the effectiveness of Murphy Oil Corporation's internal control over financial reporting as of December 31, 2007, Milford Haven refinery's internal control over financial reporting associated with assets of approximately $404 million, liabilities of approximately $15 million, and operating expenses and other income of approximately $39 million included in the consolidated financial statements of Murphy Oil Corporation as of and for the year ended December 31, 2007. Our audit of internal control over financial reporting of Murphy Oil Corporation also excluded an evaluation of the internal control over financial reporting of the remaining 70% interest of the Milford Haven refinery.

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, 2007 and 2006, 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, 2007, and our report dated February 29, 2008, expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Houston, Texas
February 29, 2008

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(Thousands of dollars except per share amounts)*	2007	2006*	2005*
Revenues			
Sales and other operating revenues	**$ 18,423,771**	14,279,325	11,680,079
Gain (loss) on sale of assets	**(365)**	9,388	175,140
Interest and other income	**15,692**	18,674	21,932
Total revenues	**18,439,098**	14,307,387	11,877,151
Costs and Expenses			
Crude oil and product purchases	**14,882,618**	11,214,235	8,783,042
Operating expenses	**1,312,030**	1,093,213	835,672
Exploration expenses, including undeveloped lease amortization	**203,065**	219,238	232,400
Selling and general expenses	**229,300**	228,543	158,808
Depreciation, depletion and amortization	**489,837**	384,063	396,875
Impairment of properties	**40,708**	—	—
Accretion of asset retirement obligations	**16,244**	10,921	9,704
Net costs associated with hurricanes	**3,000**	109,244	66,770
Interest expense	**75,493**	52,549	47,304
Interest capitalized	**(49,881)**	(43,073)	(38,539)
Minority interest	**(548)**	56	—
Total costs and expenses	**17,201,866**	13,268,989	10,492,036
Income from continuing operations before income taxes	**1,237,232**	1,038,398	1,385,115
Income tax expense	**470,703**	393,729	538,922
Income from continuing operations	**766,529**	644,669	846,193
Income from discontinued operations, net of tax	**—**	—	8,549
Net Income	**$ 766,529**	644,669	854,742
Income per Common Share – Basic			
Income from continuing operations	**$ 4.08**	3.46	4.59
Income from discontinued operations	**—**	—	.05
Net Income – Basic	**$ 4.08**	3.46	4.64
Income per Common Share – Diluted			
Income from continuing operations	**$ 4.01**	3.41	4.50
Income from discontinued operations	**—**	—	.05
Net Income – Diluted	**$ 4.01**	3.41	4.55
Average Common shares outstanding – basic	**188,027,557**	186,105,086	184,354,552
Average Common shares outstanding – diluted	**191,140,737**	189,158,411	187,889,378

* Adjusted to reflect adoption of FASB Staff Position No. AUG AIR-1; See Note P.

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

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

December 31 *(Thousands of dollars)*	2007	2006*
Assets		
Current assets		
Cash and cash equivalents	**$ 673,707**	543,390
Accounts receivable, less allowance for doubtful accounts of $7,484 in 2007 and $10,408 in 2006	**1,420,601**	995,089
Inventories, at lower of cost or market		
Crude oil and blend stocks	**159,379**	73,696
Finished products	**315,977**	224,469
Materials and supplies	**151,291**	112,912
Prepaid expenses	**79,585**	136,674
Deferred income taxes	**86,252**	20,861
Total current assets	**2,886,792**	2,107,091
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $3,516,338 in 2007 and $2,872,293 in 2006	**7,109,822**	5,106,282
Goodwill	**51,450**	44,057
Deferred charges and other assets	**487,785**	225,731
Total assets	**$10,535,849**	7,483,161
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long-term debt	**$ 5,208**	4,466
Notes payable	**7,561**	2,659
Accounts payable	**1,662,401**	1,008,597
Income taxes payable	**108,783**	63,003
Other taxes payable	**199,809**	151,435
Other accrued liabilities	**125,500**	80,945
Total current liabilities	**2,109,262**	1,311,105
Notes payable	**1,513,015**	833,126
Nonrecourse debt of a subsidiary	**3,141**	7,149
Deferred income taxes	**916,910**	621,329
Asset retirement obligations	**336,107**	237,875
Deferred credits and other liabilities	**564,374**	327,964
Minority interest	**26,866**	23,340
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, 2007 and 2006, issued 189,972,970 shares at December 31, 2007 and 187,691,508 shares at December 31, 2006	**189,973**	187,692
Capital in excess of par value	**547,185**	454,860
Retained earnings	**3,983,998**	3,349,832
Accumulated other comprehensive income	**351,765**	131,999
Treasury stock	**(6,747)**	(3,110)
Total stockholders' equity	**5,066,174**	4,121,273
Total liabilities and stockholders' equity	**$10,535,849**	7,483,161

* Adjusted to reflect adoption of FASB Staff Position No. AUG AIR-1; See Note P.

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

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(Thousands of dollars)*	2007	2006*	2005*
Operating Activities			
Net income	$ **766,529**	644,669	854,742
Income from discontinued operations	**—**	—	(8,549)
Income from continuing operations	**766,529**	644,669	846,193
Adjustments to reconcile income from continuing operations to net cash provided by operating activities			
Depreciation, depletion and amortization	**489,837**	384,063	396,875
Impairment of long-lived assets	**40,708**	—	—
Amortization of deferred major repair costs	**22,107**	17,720	21,964
Expenditures for asset retirements	**(13,039)**	(3,328)	(8,250)
Dry hole costs	**67,052**	111,044	125,992
Amortization of undeveloped leases	**33,215**	22,466	22,819
Accretion of asset retirement obligations	**16,244**	10,921	9,704
Deferred and noncurrent income tax charges	**102,507**	33,091	45,521
Pretax (gains) losses from disposition of assets	**365**	(9,388)	(175,140)
Net decrease (increase) in noncash operating working capital	**145,454**	(255,970)	(49,413)
Other operating activities – net	**69,441**	20,190	4,117
Net cash provided by continuing operations	**1,740,420**	975,478	1,240,382
Net cash provided by discontinued operations	**—**	—	8,549
Net cash provided by operating activities	**1,740,420**	975,478	1,248,931
Investing Activities			
Property additions and dry hole costs	**(1,949,219)**	(1,191,670)	(1,246,242)
Acquisition of Milford Haven refinery, including inventory	**(348,292)**	—	—
Proceeds from sale of property, plant and equipment	**21,636**	23,843	172,653
Expenditures for major repairs	**(14,649)**	(12,776)	(23,669)
Proceeds from maturity of investment securities	**—**	—	17,892
Other investing activities – net	**4,011**	(10,839)	(9,943)
Net cash required by investing activities	**(2,286,513)**	(1,191,442)	(1,089,309)
Financing Activities			
Additions to notes payable	**686,194**	237,658	—
Reductions of notes payable	**(825)**	(14)	(46,386)
Reductions of nonrecourse debt of a subsidiary	**(4,903)**	(4,667)	(4,193)
Proceeds from exercise of stock options and employee stock purchase plans	**41,624**	24,864	26,513
Excess tax benefits related to exercise of stock options	**30,805**	11,756	—
Cash dividends paid	**(127,353)**	(98,162)	(83,198)
Other financing activities – net	**(760)**	—	(1,053)
Net cash provided (required) by financing activities	**624,782**	171,435	(108,317)
Effect of exchange rate changes on cash and cash equivalents	**51,628**	2,586	(1,497)
Net increase (decrease) in cash and cash equivalents	**130,317**	(41,943)	49,808
Cash and cash equivalents at January 1	**543,390**	585,333	535,525
Cash and cash equivalents at December 31	$ **673,707**	543,390	585,333

* Adjusted to reflect adoption of FASB Staff Position No. AUG AIR-1; See Note P.

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

Years Ended December 31 *(Thousands of dollars)*	2007	2006	2005
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	—	—	—
Common Stock – par $1.00, authorized 450,000,000 shares at December 31, 2007, 2006 and 2005, issued 189,972,970 shares at December 31, 2007, 187,691,508 shares at December 31, 2006 and 186,828,618 shares at December 31, 2005			
Balance at beginning of year	**$ 187,692**	186,829	94,613
Exercise of stock options	**2,281**	863	—
Two-for-one stock split effective June 3, 2005	—	—	92,216
Balance at end of year	**189,973**	187,692	186,829
Capital in Excess of Par Value			
Balance at beginning of year	**454,860**	437,963	511,045
Exercise of stock options, including income tax benefits	**63,702**	23,956	1,582
Restricted stock transactions and other	**3,794**	(1,390)	16,407
Amortization, forfeitures and other	**23,784**	10,180	—
Sale of stock under employee stock purchase plans	**1,045**	561	1,145
Reclassification from Unamortized Restricted Stock Awards upon adoption of SFAS No. 123R	—	(16,410)	—
Two-for-one stock split effective June 3, 2005	—	—	(92,216)
Balance at end of year	**547,185**	454,860	437,963
Retained Earnings			
Balance at beginning of year as previously reported	**3,349,832**	2,803,325	1,981,020
Cumulative effect of adopting FASB Staff Position No. AUG AIR-1	—	—	50,761
Balance at beginning of year as adjusted	**3,349,832**	2,803,325	2,031,781
Cumulative effect of changes in accounting principles	**(5,010)**	—	—
Net income for the year	**766,529**	644,669	854,742
Cash dividends – $.675 per share in 2007, $.525 per share in 2006 and $.45 per share in 2005	**(127,353)**	(98,162)	(83,198)
Balance at end of year	**3,983,998**	3,349,832	2,803,325
Accumulated Other Comprehensive Income			
Balance at beginning of year	**131,999**	133,353	134,509
Cumulative effect of adopting FASB Staff Position No. AUG AIR-1	—	—	2,715
Balance at beginning of year as adjusted	**131,999**	133,353	137,224
Cumulative effect of changes in accounting principles	**1,345**	—	—
Foreign currency translation gains, net of income taxes	**204,266**	37,143	17,374
Cash flow hedging gains (losses), net of income taxes	—	13,459	(18,041)
Retirement and postretirement benefit plan adjustments, net of income taxes	**14,155**	(819)	(3,204)
Adjustment to initially apply SFAS No. 158, net of income taxes	—	(51,137)	—
Balance at end of year	**351,765**	131,999	133,353
Unamortized Restricted Stock Awards			
Balance at beginning of year	—	(16,410)	(4,738)
Reclassification to Capital in Excess of Par Value upon adoption of SFAS No. 123R	—	16,410	—
Stock awards	—	—	(16,344)
Amortization, forfeitures and other	—	—	4,672
Balance at end of year	—	—	(16,410)
Treasury Stock			
Balance at beginning of year	**(3,110)**	(22,990)	(67,293)
Exercise of stock options	—	13,345	38,790
Sale of stock under employee stock purchase plans	**982**	737	1,182
Awarded restricted stock, net of forfeitures	**(4,619)**	5,798	4,331
Balance at end of year – 258,821 shares of Common Stock in 2007, 119,308 shares in 2006 and 881,940 shares in 2005	**(6,747)**	(3,110)	(22,990)
Total Stockholders' Equity	**$5,066,174**	4,121,273	3,522,070

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

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(Thousands of dollars)*	2007	2006*	2005*
Net income	**$766,529**	644,669	854,742
Other comprehensive income (loss), net of tax			
Cash flow hedges			
Net derivative losses	**—**	(5,154)	(15,670)
Reclassification to income	**—**	18,613	(2,371)
Total cash flow hedges	**—**	13,459	(18,041)
Net gain from foreign currency translation	**204,266**	37,143	17,374
Retirement and postretirement plan adjustments	**14,155**	(819)	(3,204)
Other comprehensive income (loss)	**218,421**	49,783	(3,871)
Comprehensive Income	**$984,950**	694,452	850,871

* Adjusted to reflect adoption of FASB Staff Position No. AUG AIR-1; See Note P.

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note A – Significant Accounting Policies

NATURE OF BUSINESS – Murphy Oil Corporation is an international oil and gas company that conducts its business through various operating subsidiaries. The Company produces oil and/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, 2007 and 2006, the liabilities for natural gas balancing were immaterial. Excise taxes collected on sales of refined products and remitted to governmental agencies are not included in revenues or in costs and expenses.

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.

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.

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), 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 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-34 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. As more fully described in Note P, effective January 1, 2007, the Company changed its method of accounting for turnarounds and has adjusted all prior year financial statements presented to apply this policy. Beginning in 2007, 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. 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. Materials and supplies are valued at the lower of average cost or estimated value.

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 2007 was caused by a change in the foreign currency translation rate between years. 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, 2007. 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.

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 I, 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 – Effective January 1, 2006, the Company adopted SFAS No. 123R, Share-Based Payment, using the modified prospective application. Upon adoption, the Company began to expense the fair value of stock options over the remaining vesting period. The Company uses the Black-Scholes model for computing the fair value of stock options. Stock option expense is recognized on a straight-line based over the respective vesting period of two or three years. The Company continued to expense the fair value of performance-based restricted stock awards over the vesting period, but beginning with the 2006 awards, it used a Monte Carlo valuation model to determine the fair value of these awards. The Company continued to expense the fair value of time-lapse restricted stock over the vesting period, with the fair value based on the price of Company stock on the date of grant. Prior to 2006, the Company accounted for stock options using the intrinsic-value based method prescribed by Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees and related interpretations.

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 FSP AUG AIR -1, Accounting for Planned Major Maintenance Activities (FSP AUG AIR-1), which prohibited, effective January 1, 2007, the use of the accrue-in-advance method of accounting for planned major maintenance activities as historically used by the Company. Accordingly, the Company has chosen to use the permitted deferral method of accounting for planned major maintenance activities such as refinery turnarounds beginning in 2007. Under the deferral method, the actual cost of each planned major maintenance activity is deferred and amortized through the next turnaround. All prior period financial statements have been adjusted to reflect the adoption of FSP AUG AIR-1 as if the deferral method was in effect in prior periods. A cumulative after-tax adjustment to increase Stockholders' Equity of $50,761,000 has been recorded as of January 1, 2005 to effect the adoption of FSP AUG AIR-1. Refer to Note P for further information.

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 K 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. 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 on January 1, 2007, 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 I for further information.

In September 2006, the U.S. Securities and Exchange Commission released Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements (SAB 108), which provides interpretive guidance on the SEC's views regarding the process of quantifying materiality of financial statement misstatements. SAB 108 was effective for fiscal years ending after November 15, 2006, with early application for the first interim period ending after November 15, 2006. The adoption of this standard at December 31, 2006 had no impact on the Company's financial statements.

In June 2006, the Emerging Issues Task Force (EITF) finalized Issue 06-3, How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement. The Task Force reached a consensus that this EITF applied to any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but is not limited to sales, use, value added, and some excise taxes. The EITF concluded that the presentation of taxes within the scope of this issue may be either gross (included in revenues and costs) or net (excluded from revenues and costs) and is an accounting policy decision that should be disclosed by the Company. The Company excludes excise taxes collected on sales of refined products and remitted to governmental agencies from its revenues and costs of sales.

In March 2005, the EITF decided in Issue 04-6 that mining operations should account for post-production stripping costs as a variable production cost that should be considered a component of mineral inventory costs. The Company's synthetic oil operation at Syncrude is affected by this ruling, which was effective as of January 1, 2006 for the Company. The Company has determined that the level of bitumen inventory at Syncrude affected by this EITF consensus is immaterial and it has continued to expense post-production stripping costs as incurred.

Recent Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. 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 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 does not expect the initial adoption of this statement to have a material impact on its 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 is effective January 1, 2008 for the Company. The Company is considering SFAS No. 159, and at this time the Company does not expect to elect the fair value option for any financial assets and financial liabilities.

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. This new guidance will be effective for the Company beginning in 2008, and will require 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 Company does not expect the adoption of this consensus to have a material impact on its financial statements.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51. 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. This statement is effective for the Company beginning January 1, 2009. 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 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.

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.

Revenue and expenses associated with the 70% interest acquired have been included in the Company's consolidated financial statements beginning on December 1, 2007.

The Company has performed a preliminary allocation of the purchase price as of December 1, 2007, including associated direct expenses of the acquisition, based on estimated fair values of the assets acquired and liabilities assumed as of December 1, 2007, as follows:

(Thousands of dollars)	
Purchase Price	
Cash paid	$337,214
Transaction costs	11,078
	$348,292
Preliminary Allocation	
Refinery process units and equipment	$322,550
Inventory	106,641
All other assets	984
Deferred tax liabilities	(76,883)
All other long-term liabilities	(5,000)
	$348,292

The purchase price allocation will be adjusted if any additional significant assets or liabilities are indentified during 2008. 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 – Discontinued Operations

The Company sold most of its western Canadian conventional oil and gas assets and recorded a gain from sale of the properties in 2004. In 2005, the Company recognized additional income on the sale of $8,549,000 due to a favorable adjustment of previously recorded income tax expense.

Note E – Property, Plant and Equipment

	December 31, 2007		December 31, 2006	
(Thousands of dollars)	Cost	Net	Cost	Net
Exploration and production[1]	$ 7,748,041	5,316,671[2]	5,739,946	3,836,193[2]
Refining	1,665,807	922,443	1,255,223	565,363
Marketing	1,133,788	822,580	909,150	655,463
Corporate and other	78,524	48,128	74,256	49,263
	$ 10,626,160	7,109,822	7,978,575	5,106,282
[1] Includes mineral rights as follows:	$ 461,974	377,307	199,739	123,781
[2] Includes $13,730 in 2007 and $27,010 in 2006 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 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 for net proceeds of Cdn $103,800,000. The net investment in Berkana was approximately Cdn $58,100,000 at December 31, 2007. A net gain on sale of Berkana shares will be recorded in the first quarter 2008.

During 2005, the Company sold certain mature oil and gas properties on the continental shelf of the Gulf of Mexico and recorded a pretax gain of $175,140,000.

In 2007, the Company entered into an agreement with Wal-Mart Stores, Inc. to purchase parcels of property leased from Wal-Mart for its Murphy USA retail gasoline stations. The site purchases began in 2007 and will continue into 2008 with expected total capital expenditures of approximately $315,000,000. In conjunction with this agreement, the Company closed 55 stations in the U.S. and Canada. In the Consolidated Statements of Income for 2007, the Company recorded noncash charges of $40,708,000 primarily for impairment of these retail gasoline stations in the U.S. and Canada. The charge includes writedown of remaining undepreciated book value of the station improvements as well as costs of abandonment.

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. The adoption of this FSP did not have any effect on the Company's net income or financial condition.

At December 31, 2007, 2006 and 2005, the Company had total capitalized drilling costs pending the determination of proved reserves of $272,155,000, $315,445,000 and $275,256,000, respectively. The following table reflects the net changes in capitalized exploratory well costs during the three-year period ended December 31, 2007.

(Thousands of dollars)	**2007**	**2006**	**2005**
Beginning balance at January 1	**$ 315,445**	275,256	106,105
Additions to capitalized exploratory well costs pending the determination of proved reserves	**6,856**	158,234	169,151
Reclassifications to proved properties based on the determination of proved reserves	**(50,146)**	(114,614)	—
Capitalized exploratory well costs charged to expense or sold	**—**	(3,431)	—
Ending balance at December 31	**$ 272,155**	315,445	275,256

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.

(Thousands of dollars)	**2007**	**2006**	**2005**
Exploratory well costs capitalized for one year or less	**$ 8,851**	122,399	172,596
Exploratory well costs capitalized for more than one year	**263,304**	193,046	102,660
Balance at December 31	**$ 272,155**	315,445	275,256
Number of projects with exploratory well costs that have been capitalized for more than one year	**9**	11	8

Of the $263,304,000 of exploratory well costs capitalized more than one year, $160,609,000 is in Malaysia, $60,251,000 is in the Republic of Congo, $34,275,000 is in the U.S., and $8,169,000 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 Congo a development program is underway for the offshore Azurite field. In the U.S. drilling and development operations are planned, and in Canada a continuing drilling and development program is underway.

Note F – Financing Arrangements

At December 31, 2007, the Company had a $1,962,000,000 committed credit facility with a major banking consortium that matures in June 2012. Between June 2010 and June 2011, the committed facility capacity is reduced to $1,905,000,000 and between June 2011 and June 2012 the maximum facility is $1,828,000,000. At December 31, 2007, the Company had borrowed $718,500,000 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, 2007 the Company had borrowed $197,000,000 under uncommitted credit lines, and had additional uncommitted amounts available of about $440,000,000 in a combination of U.S. and Canadian dollars. If necessary, the Company could convert borrowings under these uncommitted lines to the committed long-term credit facility outstanding through 2012. In addition, the Company has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of up to $650,000,000 in debt and/or equity securities.

Additionally, one of the Company's subsidiaries has a Cdn $25,000,000 revolving credit facility that matures in May 2008. There was US $7,561,000 of short-term notes payable drawn under this facility at December 31, 2007. Borrowings under this facility bear interest at prime plus varying cost of funds. All of the subsidiary's present and after-acquired property and assets (real, immovable and leasehold) are pledged as collateral. The net book value of these pledged assets was $96,047,000 as of December 31, 2007.

Note G – Long-term Debt

(Thousands of dollars)	December 31 2007	2006
Notes payable		
6.375% notes, due 2012, net of unamortized discount of $499 at December 31, 2007	**$ 349,501**	349,386
7.05% notes, due 2029, net of unamortized discount of $1,986 at December 31, 2007	**248,014**	247,922
Notes payable to banks, 4.05% to 5.86% at December 31, 2007	**915,500**	235,000
Other, 6% to 8%	**—**	825
Total notes payable	**1,513,015**	833,133
Nonrecourse debt of a subsidiary		
Loans payable to Canadian government, interest free, payable in Canadian dollars, due 2008–2009	**8,349**	11,608
Total debt including current maturities	**1,521,364**	844,741
Current maturities	**(5,208)**	(4,466)
Total long-term debt	**$1,516,156**	840,275

Maturities for the four years after 2008 are: $3,141,000 in 2009, nil in 2010 and 2011, and $1,265,001,000 in 2012.

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 H – Asset Retirement Obligations

The majority of the asset retirement obligations (ARO) recognized by the Company at December 31, 2007 and 2006 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.

(Thousands of dollars)	2007	2006
Balance at beginning of year	**$237,875**	176,823
Accretion expense	**16,244**	10,921
Liabilities incurred	**50,686**	51,899
Revision of previous estimates	**29,103**	1,463
Liabilities settled	**(13,039)**	(4,061)
Changes due to translation of foreign currencies	**15,238**	830
Balance at end of year	**$336,107**	237,875

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.

Note I – Income Taxes

The components of income from continuing operations before income taxes for each of the three years ended December 31, 2007 and income tax expense (benefit) attributable thereto were as follows.

(Thousands of dollars)	2007	2006	2005
Income from continuing operations before income taxes			
United States	**$ 415,124**	339,426	637,816
Foreign	**822,108**	698,972	747,299
	$1,237,232	1,038,398	1,385,115
Income tax expense (benefit) from continuing operations			
Federal – Current	**$ 82,033**	120,591	165,019
Deferred	**56,407**	(8,210)	46,695
	138,440	112,381	211,714
State	**15,969**	2,245	10,747
Foreign – Current*	**269,080**	241,353	319,976
Deferred*	**47,214**	37,750	(3,515)
	316,294	279,103	316,461
Total	**$ 470,703**	393,729	538,922

* 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 $33,895,000 in 2007, $13,680,000 in 2006 and $15,567,000 in 2005 were included in Capital in Excess of Par Value in the Consolidated Balance Sheets. Income tax benefits (charges) of $(5,398,000) in 2006 and $7,795,000 in 2005 relating to derivatives were included in Accumulated Other Comprehensive Income (AOCI).

Total income tax expense in 2005, including taxes associated with discontinued operations, was $525,607,000.

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

(Thousands of dollars)	2007	2006	2005
Income tax expense based on the U.S. statutory tax rate	**$433,031**	363,439	484,790
Foreign income subject to foreign taxes at a rate different than the U.S. statutory rate	**35,920**	22,987	8,992
State income taxes, net of federal benefit	**10,380**	1,459	6,986
Changes in foreign tax rates	**(38,687)**	(19,709)	—
Increase in deferred tax asset valuation allowance related to foreign exploration expenditures	**12,533**	20,147	43,691
Canadian withholding tax and federal tax on dividend	**—**	—	8,520
Settlement of U.S. and foreign taxes	**—**	—	(21,849)
Other, net	**17,526**	5,406	7,792
Total	**$470,703**	393,729	538,922

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2007 and 2006 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	**2007**	**2006**
Deferred tax assets		
Property and leasehold costs	**$ 198,830**	219,467
Liabilities for dismantlements	**88,139**	76,758
Postretirement and other employee benefits	**87,906**	87,703
Foreign tax credit carryforwards	**41,043**	41,043
Other deferred tax assets	**107,219**	71,796
Total gross deferred tax assets	**523,137**	496,767
Less valuation allowance	**(214,120)**	(205,809)
Net deferred tax assets	**309,017**	290,958
Deferred tax liabilities		
Property, plant and equipment	**(307,008)**	(145,992)
Accumulated depreciation, depletion and amortization	**(587,331)**	(532,299)
Deferred major repair costs	**(9,451)**	(20,392)
Foreign currency translation gains	**(150,005)**	(69,679)
Other deferred tax liabilities	**(98,748)**	(107,650)
Total gross deferred tax liabilities	**(1,152,543)**	(876,012)
Net deferred tax liabilities	**$ (843,526)**	(585,054)

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 Company recorded deferred tax benefits of $31,858,000 in 2004 to recognize anticipated future tax benefits on exploration and other expenses related to Block K in Malaysia. The valuation allowance increased $8,311,000 in 2007, 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.

During 2005, the Company recorded income tax expense of $8,520,000 related to repatriation of U.K. and Canadian earnings to the U.S. The most significant portion of the expense related to a 5% withholding tax on funds repatriated from Canada. This tax was not recorded in prior years because, until the sale of most western Canadian assets occurred in 2004, these funds were considered permanently invested, and therefore, met the criteria for not recording income tax expense. The Company has not recognized a deferred tax liability for undistributed earnings of its Canadian subsidiaries because such earnings are considered permanently invested in foreign countries. As of December 31, 2007, undistributed earnings of Canadian subsidiaries considered permanently invested were approximately $1,611,000,000. 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 $80,550,000. The Company does not consider undistributed earnings from certain other international operations to be permanently 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. In 2005, the Company recorded benefits to income of $21,849,000 from settlements of U.S. and foreign tax issues primarily related to prior years. 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 phases in at 3% in 2005 and reaches 9% in 2010. 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 $4,725,000, $2,450,000 and $3,500,000 in 2007, 2006 and 2005, 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 benefits 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, 2007 follows.

(Thousands of dollars)	2007
Balance at January 1, 2007	**$16,436**
Additions for tax positions related to 2007	**9,101**
Changes due to translation of foreign currencies	**61**
Balance at December 31, 2007	**$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 the date of adoption (January 1, 2007) and December 31, 2007 for interest and penalties of $5,562,000 and $4,065,000, respectively, associated with uncertain tax positions. Income tax expense for the year ended December 31, 2007 included a benefit for interest and penalties of $2,228,000 associated with uncertain tax positions.

During the next twelve months, the Company currently expects to add to the liability for uncertain taxes for 2008 events in amounts that approximate the liabilities included for 2007. Although existing liabilities could be reduced by settlement with taxing authorities or lapse due to statute of limitations, the Company believes that the changes in its unrecognized tax benefits due to these events will not have a material impact on the Consolidated Statement of Income during 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, 2007, the earliest years remaining open for audit and/or settlement in our major taxing jurisdictions are as follows: United States – 2003; Canada – 2002; United Kingdom – 2005; Malaysia – 2004; and Ecuador – 2000.

Note J – Incentive Plans

The FASB issued Statement of Financial Accounting Standards (SFAS) No. 123 (revised 2004), Share-Based Payment (SFAS No. 123R), which replaced SFAS No. 123, Accounting for Stock-Based Compensation (SFAS No. 123), and superseded APB Opinion No. 25, Accounting for Stock Issued to Employees (APB No. 25). 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. The Company adopted SFAS No. 123R as of January 1, 2006.

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 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.

(Thousands of dollars)	2007	2006	2005
Compensation charged against income before income tax benefit	**$ 22,241**	18,814	15,633
Related income tax benefit recognized in income	**7,778**	6,112	5,449

As of December 31, 2007, there was $29,269,000 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, 2007, 2006 and 2005 was $41,624,000, $24,864,000 and $26,513,000, respectively. Total income tax benefits realized from tax deductions related to stock option exercises under share-based payment arrangements were $32,844,000, $14,134,000 and $16,073,000 for the years ended December 31, 2007, 2006 and 2005, respectively.

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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.

	2007	2006	2005
Fair value per option grant	**$15.02**	$17.53	$11.79
Assumptions			
Dividend yield	**1.20%**	0.90%	1.25%
Expected volatility	**29.00%**	30.00%	26.00%
Risk-free interest rate	**4.70%**	4.42%	3.74%
Expected life	**4.75yrs.**	4.75yrs.	5.00yrs.

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

	Number of Shares	Average Exercise Price
Outstanding at December 31, 2004	9,037,580	$18.47
Granted at FMV	935,000	45.23
Exercised	(1,488,063)	15.96
Forfeited	(69,880)	15.49
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**
Exercisable at December 31, 2005	5,576,829	$16.49
Exercisable at December 31, 2006	5,544,656	18.31
Exercisable at December 31, 2007	**3,997,010**	**22.44**

Additional information about stock options outstanding at December 31, 2007 is shown below.

	Options Outstanding			Options Exercisable		
Range of Exercise Prices per Option	No. of Options	Avg. Life in Years	Aggregate Intrinsic Value	No. of Options	Avg. Life in Years	Aggregate Intrinsic Value
$ 8.92 to $ 14.24	574,000	1.4	$ 41,481,000	574,000	1.4	$ 41,481,000
$ 15.11 to $ 23.58	2,340,750	4.2	153,925,000	2,340,750	4.2	153,925,000
$ 30.29 to $ 57.32	2,886,760	4.7	113,176,000	1,082,260	3.5	54,009,000
	5,801,510	4.2	$308,582,000	3,997,010	3.6	$249,415,000

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 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. In the event that the shares awarded in 2006 vest, the Company shall reimburse grantees up to 50% of the fair market value of the restricted stock for personal income tax liability. Changes in performance-based restricted stock and restricted stock units outstanding for each of the last three years are presented in the following table.

(Number of shares)	2007	2006	2005
Balance at beginning of year	**680,292**	478,445	157,000
Granted	**299,000**	265,750	336,000
Forfeited	**(180,795)**	(63,903)	(14,555)
Balance at end of year	**798,497**	680,292	478,445

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

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 2007 and 2006 are presented in the following table.

	2007	2006
Fair value per share at grant date	**$45.05 – 48.23**	$ 37.33
Assumptions		
Expected volatility	**27.10%**	26.30%
Risk-free interest rate	**4.64%**	4.49%
Stock beta	**0.912**	0.955
Expected life	**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. 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 $51.07 per share in 2007, $57.32 per share in 2006 and $45.23 per share in 2005. Changes in time-lapse restricted stock outstanding for each of the periods are presented in the following table.

(Number of shares)	2007	2006	2005
Balance at beginning of year	**56,142**	35,574	12,624
Granted	**32,750**	20,568	22,950
Expired	**(15,706)**	—	—
Forfeited	**(4,897)**	—	—
Balance at end of year	**68,289**	56,142	35,574

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 30,011 shares at an average price of $52.68 per share in 2007, 28,280 shares at $45.88 per share in 2006 and 33,425 shares at $43.30 per share in 2005. At December 31, 2007, 471,194 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 $253,000 in 2007 and $256,000 in 2006. The fair value per share of the ESPP was approximately $8.32 per share and $7.57 for the years ended December 31, 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 July 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 $23,716,000, $14,862,000 and $17,634,000 was recorded in 2007, 2006 and 2005, respectively, for these plans.

PRO FORMA EFFECT – Prior to adopting SFAS No. 123R, the Company used the intrinsic-value based method of accounting as prescribed by APB No. 25 and related interpretations to account for share-based compensation including stock options. Under this method, the Company accrued costs of restricted stock and any stock options deemed to be variable in nature over the vesting/performance period and adjusted such costs for changes in the fair market value of Common Stock. No compensation expense was recorded for fixed stock options since all option prices were equal to or greater than the fair market value of the Company's stock on the date of grant. Had the Company recorded compensation expense for stock options as prescribed by SFAS No. 123, net income and earnings per share for the year ended December 31, 2005 would have been the pro forma amounts shown in the following table.

(Thousands of dollars except per share data)		2005
Net income – As reported		854,742
Restricted stock compensation expense included in income, net of tax		5,829
Total stock-based compensation expense using fair value method for all awards, net of tax		(10,309)
Net income – Pro forma		850,262
Net income per share –	As reported, basic	4.64
	Pro forma, basic	4.61
	As reported, diluted	4.55
	Pro forma, diluted	4.53

Note K – Employee and Retiree Benefit Plans

PENSION AND 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.

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 recognition and disclosure requirements of SFAS No. 158 at December 31, 2006. The following table presents the incremental effect of applying SFAS No. 158 on individual line items in the Consolidated Balance Sheet at December 31, 2006.

(Thousands of dollars)	Before Application of SFAS No. 158	SFAS No. 158 Adjustments	After Application of SFAS No. 158
Deferred charges and other assets	$ 217,563	8,168	225,731
Other accrued liabilities	80,743	202	80,945
Deferred income tax liabilities	649,396	(28,067)	621,329
Deferred credits and other liabilities	240,794	87,170	327,964
Accumulated other comprehensive income	183,136	(51,137)	131,999

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 balance sheet adjustments as of January 1, 2007 were as follows.

(Thousands of dollars)	Increase (Decrease)
Deferred income taxes payable	$ (1,708)
Deferred credits and other liabilities	4,664
Retained earnings	(4,301)
Accumulated other comprehensive income	1,345

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, 2007 and 2006 and a statement of the funded status as of December 31, 2007 and 2006.

	Pension Benefits		Postretirement Benefits	
(Thousands of dollars)	2007	2006	2007	2006
Change in benefit obligation				
Obligation at January 1	**$ 429,398**	388,018	**72,567**	71,224
Adjustment due to adoption of SFAS No. 158	**2,606**	—	**1,685**	—
Service cost	**11,424**	10,264	**2,283**	2,128
Interest cost	**24,492**	21,670	**4,354**	3,923
Plan amendments	**—**	7,752	**—**	—
Participant contributions	**51**	47	**941**	818
Actuarial (gain) loss	**(5,456)**	6,782	**3,257**	954
Medicare Part D subsidy	**—**	—	**387**	289
Exchange rate changes	**5,313**	10,234	**—**	—
Benefits paid	**(21,442)**	(18,916)	**(4,789)**	(5,467)
Special termination benefits	**—**	3,796	**—**	(1,044)
Other	**—**	(249)	**—**	(258)
Obligation at December 31	**446,386**	429,398	**80,685**	72,567
Change in plan assets				
Fair value of plan assets at January 1	**313,214**	300,384	**—**	—
Adjustment due to adoption of SFAS No. 158	**3,736**	—	**—**	—
Actual return on plan assets	**25,107**	16,887	**—**	—
Employer contributions	**12,156**	7,675	**3,461**	4,360
Participant contributions	**51**	47	**941**	818
Medicare Part D subsidy	**—**	—	**387**	289
Exchange rate changes	**6,785**	7,410	**—**	—
Benefits paid	**(21,442)**	(18,916)	**(4,789)**	(5,467)
Other	**(348)**	(273)	**—**	—
Fair value of plan assets at December 31	**339,259**	313,214	**—**	—
Funded status and amounts recognized in the Consolidated Balance Sheets at December 31				
Deferred charges and other assets	**17,649**	16,813	**—**	—
Other accrued liabilities	**(33,251)**	(4,215)	**—**	—
Deferred credits and other liabilities	**(91,525)**	(128,782)	**(80,685)**	(72,567)
Funded status and net plan liability recognized at December 31	**$(107,127)**	(116,184)	**(80,685)**	(72,567)

At December 31, 2007, 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.

(Thousands of dollars)	Pension Benefits 2007	Postretirement Benefits 2007
Net loss	**$ (93,260)**	**(31,365)**
Prior service (cost) credit	**(8,395)**	**2,775**
Transitional costs	**(3,467)**	**—**
	$(105,122)	**(28,590)**

Amounts included in AOCI at December 31, 2007 that are expected to be amortized into net periodic benefit expense during 2008 are shown in the following table.

(Thousands of dollars)	Pension Benefits	Postretirement Benefits
Net loss	**$(4,151)**	**(1,671)**
Prior service (cost) credit	**(1,321)**	**264**
Transitional costs	**(495)**	**—**
	$(5,967)	**(1,407)**

A minimum pension liability adjustment was required for certain of the Company's plans in 2005. After reductions for amounts charged to intangible assets, net of associated deferred income taxes, comprehensive income was reduced by charges of $3,204,000 in 2005.

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

	Projected Benefit Obligations		Accumulated Benefit Obligations		Fair Value of Plan Assets	
(Thousands of dollars)	2007	2006	2007	2006	2007	2006
Funded qualified plans where PBO exceeds fair value of plan assets	**$ 377,503**	372,783	**330,511**	329,461	**302,970**	279,749
Unfunded nonqualified and directors' plans where PBO exceeds fair value of plan assets	**50,244**	40,202	**39,970**	29,633	**—**	—
Unfunded post retirement plans	**80,685**	72,567	**80,685**	72,567	**—**	—

The table that follows provides the components of net periodic benefit expense for each of the three years ended December 31, 2007.

	Pension Benefits			Postretirement Benefits		
(Thousands of dollars)	2007	2006	2005	2007	2006	2005
Service cost	**$ 11,424**	10,264	9,099	**2,283**	2,128	1,906
Interest cost	**24,492**	21,670	20,478	**4,354**	3,923	3,749
Expected return on plan assets	**(21,644)**	(20,315)	(19,092)	**—**	—	—
Amortization of prior service cost	**1,422**	1,929	820	**(264)**	(277)	(277)
Amortization of transitional asset	**(494)**	(490)	(624)	**—**	—	—
Recognized actuarial loss	**5,746**	6,416	5,916	**1,589**	1,637	1,595
	20,946	19,474	16,597	**7,962**	7,411	6,973
Special termination benefits expense	**—**	4,748	—	**—**	—	—
Curtailment expense (benefit)	**—**	594	—	**—**	(152)	—
Net periodic benefit expense	**$ 20,946**	24,816	16,597	**7,962**	7,259	6,973

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

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

(Thousands of dollars)	Pension Benefits		Postretirement Benefits	
	2007	2006	2007	2006
Benefit obligation at December 31	**$ 117,224**	107,473	—	—
Fair value of plan assets at December 31	**106,058**	98,072	—	—
Net plan liability recognized	**11,166**	9,401	—	—
Net periodic benefit expense	**3,342**	3,004	—	—

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2007 and 2006 and net periodic benefit expense for the years 2007 and 2006.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits		Postretirement Benefits		Pension Benefits		Postretirement Benefits	
	December 31		December 31		Year		Year	
	2007	2006	2007	2006	2007	2006	2007	2006
Discount rate	**6.25%**	5.71%	**6.50%**	6.00%	**5.76%**	5.48%	**6.00%**	5.70%
Expected return on plan assets	**6.93%**	6.89%	**—**	—	**6.89%**	6.89%	**—**	—
Rate of compensation increase	**4.42%**	4.46%	**—**	—	**4.40%**	4.09%	**—**	—

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, 2007 and September 30, 2006 are presented in the following table.

	December 31, 2007	September 30, 2006
Equity securities	**57.3%**	52.3%
Debt securities	**41.4**	44.0
Cash	**1.3**	3.7
	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 6.93% in 2007 and the return was determined based on an assessment of actual long-term historical returns and expected future returns for a portfolio with investment characteristics similar to that maintained by the plans. The 6.93% expected return was based on an expected average future equity securities return of 8.77% and a debt securities return of 5.52% and is net of average expected investment expenses of 0.42%. Over the last 10 years, the return on funded retirement plan assets has averaged 6.67%.

During 2007, the Company made contributions of $9,908,000 to its domestic defined benefit pension plans, $2,248,000 to its foreign defined benefit pension plan and $3,461,000 to its domestic postretirement benefits plan. The Company currently expects during 2008 to make contributions of $34,673,000 to its domestic defined benefit pension plans, $21,886,000 to its foreign defined benefit pension plans and $4,741,000 to its domestic postretirement benefits plan.

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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.

(Thousands of dollars)	Pension Benefits	Postretirement Benefits
2008	$ 21,935	5,344
2009	22,342	5,643
2010	22,960	6,030
2011	23,700	6,365
2012	24,639	6,720
2013-2017	142,815	37,502

For purposes of measuring postretirement benefit obligations at December 31, 2007, the future annual rates of increase in the cost of health care were assumed to be 8.25% for 2008 decreasing each year to an ultimate rate of 5.0% in 2013 and thereafter.

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

(Thousands of dollars)	1% Increase	1% Decrease
Effect on total service and interest cost components of net periodic postretirement benefit expense for the year ended December 31, 2007	$ 1,033	(1,185)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 2007	10,760	(9,220)

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 $1,507,000, $1,422,000 and $1,410,000 during 2007, 2006 and 2005, 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 $9,252,000 in 2007, $2,957,000 in 2006 and $7,886,000 in 2005.

Note L – 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.

- *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. Essentially offsetting short-term derivative instruments were outstanding at December 31, 2007 to manage the purchase price of about 403,000 barrels of crude oil at the Company’s Meraux, Louisiana refinery. The total impact of marking these contracts to market was a charge of $40,000 in the year ended December 31, 2007.
- *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 and 2005 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). Other similar contracts covered a portion of 2005 purchases. 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 years ended December 31, 2006 and 2005, the income (expense) effect from cash flow hedging ineffectiveness for these contracts was $(28,000) and $1,021,000, respectively. During the years ended December 31, 2006 and 2005, the Company received approximately $2,791,000 and $7,635,000, respectively, 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 and 2005 Canadian heavy oil production by entering into forward sale contracts covering a notional volume of approximately 4,000 barrels per day in 2006 and 2,000 barrels per day in 2005. In 2006, 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. In 2005, the Company paid the average Hardisty posted price and received $29.00 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 and 2005, earnings were increased by $160,000 and $65,000, respectively, for cash flow hedging ineffectiveness on crude oil sales price hedges. During 2006 and 2005, the Company paid approximately $29,373,000 and $5,254,000, respectively, for settlement of maturing crude oil sales swaps.

FAIR VALUE – The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2007 and 2006. 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 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.

	At December 31			
	2007		2006	
(Thousands of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets (liabilities):				
Current and long-term debt	**$(1,521,364)**	**(1,517,678)**	(844,741)	(878,227)

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 M – Stockholder Rights Plan

The Company's Stockholder Rights Plan provides for each Common stockholder to receive a dividend of one Right for each share of the Company's Common Stock held. The Rights will expire on April 6, 2008 unless earlier redeemed or exchanged. The Rights will detach from the Common Stock and become exercisable following a specified period of time after the first public announcement that a person or group of affiliated or associated persons (other than certain persons) has become the beneficial owner of 15% or more of the Company's Common Stock. The Rights have certain antitakeover effects and will cause substantial dilution to a person or group that attempts to acquire the

Company without conditioning the offer on a substantial number of Rights being acquired. The Rights are not intended to prevent a takeover, but rather are designed to enhance the ability of the Board of Directors to negotiate with an acquiror on behalf of all shareholders. Other terms of the Rights are set forth in, and the foregoing description is qualified in its entirety by, the Rights Agreement, as amended, between the Company and Harris Trust Company of New York as Rights Agent.

Note N – Earnings per Share

The following table reconciles the weighted-average shares outstanding for computation of basic and diluted income per Common share for each of the three years ended December 31, 2007. No difference existed between net income used in computing basic and diluted income per Common share for these years.

(Weighted-average shares outstanding)	2007	2006	2005
Basic method	**188,027,557**	186,105,086	184,354,552
Dilutive stock options	**3,113,180**	3,053,325	3,534,826
Diluted method	**191,140,737**	189,158,411	187,889,378

Certain outstanding options to purchase shares of Common stock at year-end 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 706,000 shares at a weighted average price of $57.32 at year-end 2006. There were no antidilutive options for the 2007 and 2005 periods.

Note O – Other Financial Information

INVENTORIES – Inventories accounted for under the LIFO method totaled $361,651,000 and $214,810,000 at December 31, 2007 and 2006, respectively, and these amounts were $709,743,000 and $389,481,000 less than such inventories would have been valued using the FIFO method.

ACCUMULATED OTHER COMPREHENSIVE INCOME – At December 31, 2007 and 2006, the components of Accumulated Other Comprehensive Income were as follows.

(Thousands of dollars)	2007	2006
Foreign currency translation gains, net of tax	**$428,538**	224,894
Retirement and postretirement plan liability adjustments, net of tax	**(76,773)**	(92,895)
Balance at end of year	**$351,765**	131,999

At December 31, 2007, components of the net foreign currency translation gain of $428,538,000 were gains of $353,593,000 for Canadian dollars, $71,429,000 for pounds sterling and $3,516,000 for other currencies. Foreign currency translation gains shown in the table are net of income taxes of $150,005,000 and $69,679,000 at year-end 2007 and 2006, respectively. Net gains (losses) from foreign currency transactions included in the Consolidated Statements of Income were $(20,637,000) in 2007, $(8,000,000) in 2006 and $102,000 in 2005.

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. For the year ended December 31, 2005, AOCI decreased by $18,041,000, net of $7,795,000 in income taxes, and income increased by $1,086,000.

CASH FLOW DISCLOSURES – Cash income taxes paid were $297,274,000, $466,087,000 and $586,544,000 in 2007, 2006 and 2005, respectively. Interest paid, net of amounts capitalized, was $22,274,000, $7,270,000 and $6,095,000 in 2007, 2006 and 2005, respectively.

Noncash operating working capital (increased) decreased during each of the three years ended December 31, 2007 as follows.

(Thousands of dollars)	2007	2006	2005
Accounts receivable	**$(445,677)**	(128,004)	(162,222)
Inventories	**(107,945)**	(96,122)	(19,110)
Prepaid expenses	**57,089**	(103,435)	12,532
Deferred income tax assets	**(65,391)**	19,403	(8,867)
Accounts payable and accrued liabilities	**661,599**	95,069	264,305
Current income tax liabilities	**45,779**	(42,881)	(136,051)
Net (increase) decrease in noncash operating working capital from continuing operations, excluding acquisition of the Milford Haven refinery in 2007	**$ 145,454**	(255,970)	(49,413)

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Note P – Turnaround Accounting

Effective January 1, 2007, FSP AUG AIR-1, Accounting for Planned Major Maintenance Activities, became effective for the Company. FSP AUG AIR-1 no longer permits the Company to use the accrue-in-advance method of accounting for planned major maintenance activities such as refinery turnarounds. The Company has chosen to use the permitted deferral method for such planned major maintenance activity. All prior period financial statements have been adjusted to reflect the adoption of FSP AUG AIR-1 as if the deferral method was in effect in prior periods. A cumulative after-tax adjustment of $50,761,000 has been recorded as of January 1, 2005 as an increase to Retained Earnings to effect the adoption of FSP AUG AIR-1. Net income for the years ended December 31, 2006 and 2005 has been restated to reflect the earnings for the periods as if FSP AUG AIR-1 had been in effect during the periods. The effects for the years ended December 31, 2006 and 2005 were increases to net income of $6,390,000 ($.04 per diluted share) and $8,290,000 ($.04 per diluted share), respectively. As presented on the consolidated balance sheet as of December 31, 2006, the previously reported liability for Accrued Major Repair Costs of $71,229,000 has been removed and a noncurrent asset of $37,434,000 representing the unamortized deferred costs of planned major maintenance activities as of that date, has been added to Deferred Charges and Other Assets. In association with the adoption of FSP AUG AIR-1, the Company will present expenditures for major repairs as an investing activity in the Consolidated Statement of Cash Flows. The following consolidated financial statement items as of December 31, 2006 and for the years ended December 31, 2006 and 2005 were affected by this change in accounting principle.

	December 31, 2006		
(Thousands of dollars)	As Previously Reported	FSP AUG AIR-1 Adjustment	As Adjusted
Consolidated Balance Sheet			
Deferred charges and other assets	$ 188,297	37,434	225,731
Deferred income tax liabilities	581,920	39,409	621,329
Accrued major repair costs	71,229	(71,229)	—
Deferred credits and other liabilities	327,307	657	327,964
Retained earnings	3,284,391	65,441	3,349,832
Accumulated other comprehensive income	128,843	3,156	131,999
Total stockholders’ equity	4,052,676	68,597	4,121,273

	Year Ended December 31, 2006			Year Ended December 31, 2005		
(Thousands of dollars)	As Previously Reported	FSP AUG AIR-1 Adjustment	As Adjusted	As Previously Reported	FSP AUG AIR-1 Adjustment	As Adjusted
Consolidated Statements of Income						
Operating expenses	$ 1,103,217	(10,004)	1,093,213	848,647	(12,975)	835,672
Selling and general expenses	228,512	31	228,543	158,889	(81)	158,808
Income from continuing operations before income taxes	1,028,425	9,973	1,038,398	1,372,059	13,056	1,385,115
Income tax expense	390,146	3,583	393,729	534,156	4,766	538,922
Net income	638,279	6,390	644,669	846,452	8,290	854,742
Net income per share:						
Basic	3.43	.03	3.46	4.59	.05	4.64
Diluted	3.37	.04	3.41	4.51	.04	4.55
Consolidated Statements of Cash Flows						
Operating Activities						
Net income	638,279	6,390	644,669	846,452	8,290	854,742
Provisions for/amortization of major repair costs	27,693	(9,973)	17,720	35,020	(13,056)	21,964
Expenditures for major repairs and asset retirements	(16,104)	12,776	(3,328)	(31,919)	23,669	(8,250)
Deferred and noncurrent income tax charges	29,508	3,583	33,091	40,755	4,766	45,521
Net cash provided by operating activities	962,702	12,776	975,478	1,225,262	23,669	1,248,931
Investing Activities						
Expenditures for major repairs	—	(12,776)	(12,776)	—	(23,669)	(23,669)
Net cash required by investing activities	(1,178,666)	(12,776)	(1,191,442)	(1,065,640)	(23,669)	(1,089,309)

Note Q – Hurricane and Insurance Related Matters

In the three years ended December 31, 2007, the Company recorded pretax expenses, net of anticipated insurance recoveries, of $3,000,000, $109,244,000 and $66,770,000, 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. The components of the 2005 costs, all of which occurred in the second half of the year, included $22,945,000 for incremental insurance expenses; $15,493,000 for uninsured losses within the Company's insurance deductibles; $8,844,000 for voluntary costs for charitable donations related to hurricane relief efforts and additional employee salaries; and $19,488,000 for depreciation and salaries while the Meraux, Louisiana, refinery was temporarily idled. Total amounts receivable from insurers for hurricane-related matters were $81,482,000 at December 31, 2007, of which $18,482,000 was classified as current in the Consolidated Balance Sheet. Through 2007, the Company's refining and marketing operations received Hurricane Katrina insurance proceeds of $416,130,000, including $312,000,000 related to oil spill liabilities and $104,130,000 related to property damage incurred as a result of Hurricane Katrina. See Note S 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. In 2005, the Company received insurance proceeds of $11,258,000 related to loss of production in the Gulf of Mexico associated with prior year Hurricanes Ivan and Lili. These business interruption collections were reported in Sales and Other Operating Revenues in the Consolidated Statements of Income.

Note R – 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 $93,322,000 in 2008, $94,673,000 in 2009, $92,818,000 in 2010, $87,363,000 in 2011, and $86,462,000 in 2012. Rental expense for noncancellable operating leases, including contingent payments when applicable, was $61,439,000 in 2007, $46,336,000 in 2006 and $33,379,000 in 2005.

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 $6,824,000 in 2008, $7,097,000 in 2009, $7,380,000 in 2010, $7,676,000 in 2011, and $7,983,000 in 2012. Base facility charges and hydrogen costs incurred in 2007, 2006 and 2005 totaled $42,512,000, $23,903,000 and $21,595,000, respectively. As a result of the refinery being shut down for several months following Hurricane Katrina, the Company notified the hydrogen supplier of a force majeure event. The hydrogen supply agreement permits the base facility charge to be suspended for the period under force majeure and the contract supply period to be extended for the same period, but in no event shall the extension of the supply period exceed 1,375 days. The Company completed repairs to its refinery and began purchasing hydrogen under this agreement within the period permitted in the contract. There were no base facility charges or hydrogen costs incurred for the last four months of 2005 and the first four months of 2006.

The Company has Operating and Production Handling Agreements providing for processing and production handling services for hydrocarbon production from certain fields in the Gulf of Mexico. These agreements require minimum annual payments for processing charges through 2012. Future required minimum payments for the next five years are $10,968,000 in 2008, $14,360,000 in 2009, $1,128,000 in 2010 and 2011, and $188,000 in 2012. In addition, the Company is required to pay additional amounts depending on the actual hydrocarbon quantities processed under the agreement. Processing and handling costs incurred were $13,476,000 in 2007, $27,007,000 in 2006 and $24,297,000 in 2005.

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 $3,000,000 in 2008 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 $3,992,000 in 2007, $3,666,000 in 2006 and $2,521,000 in 2005.

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 tuition for eligible graduates of El Dorado High

School in Arkansas. The first payment was made in January 2007. 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 2007 was $2,112,000.

Commitments for capital expenditures were approximately $2,129,000,000 at December 31, 2007, including $84,000,000 for lease acquisitions in a recent Gulf of Mexico sale, $71,400,000 for costs to develop deepwater Gulf of Mexico fields, $850,300,000 for field development and future work commitments in Malaysia, $561,200,000 for field development and a work commitment in the Republic of Congo, and $157,100,000 for purchases of land underlying certain U.S. retail gasoline stations. A partial sale of the Company's working interest in the Republic of Congo was pending government approval at December 31, 2007. Once approved, the Company's commitment for field development will be reduced by approximately $178,000,000.

The Company has entered into contracts to hire various drilling rigs and associated equipment for periods beyond December 31, 2007. These rigs are primarily utilized for deepwater drilling operations in the Gulf of Mexico, Malaysia and the Republic of Congo. Future commitments under these contracts, all of which expire by 2012, total approximately $1,163,000,000. 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 S – Contingencies

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

ENVIRONMENTAL MATTERS AND LEGAL MATTERS – In addition to being subject to numerous laws and regulations intended to protect the environment and/or impose remedial obligations, the Company is also involved in personal injury and property damage claims, allegedly caused by exposure to or by the release or disposal of materials manufactured or used in the Company's operations. The Company operates or has previously operated certain sites and facilities, including three refineries, five terminals, and approximately 116 service stations for which known or potential obligations for environmental remediation exist. In addition the Company operates or has operated numerous oil and gas fields that may require some form of remediation, which is generally provided for by the Company's abandonment liability.

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.

The U.S . Environmental Protection Agency (EPA) currently considers the Company 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. Based on currently available information, the Company believes that it is a de minimis party as to ultimate responsibility at both 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 two 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.

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 $330,000,000 will be paid by insurance. The Company recorded an expense of $18,000,000 in 2006 related to settlement costs not expected to be covered by insurance. As part of the settlement, all properties in the class area will receive a fair and equitable cash payment and will have residual oil cleaned. As part of the settlement, the Company will offer to purchase all properties in an agreed area adjacent to the west side of the Meraux refinery; these property purchases and associated remediation will be paid by the Company and are expected to total $55,000,000. Approximately 75 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 where a class certification decision is pending. 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 class action 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.

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, 2007, the Company had contingent liabilities of $8,519,000 under a financial guarantee described in the following paragraph and $292,493,000 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. LOOP has issued $266,210,000 in 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, 2007, 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.

Note T – Common Stock Issued and Outstanding

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2007 is shown below.

(Number of shares outstanding)	2007	2006	2005
At beginning of year	**187,572,200**	185,946,678	92,035,377
Stock options exercised	**2,249,300**	1,374,827	1,488,063
Employee stock purchase and thrift plans	**37,679**	28,280	45,344
Restricted stock awards, net of forfeitures	**(144,442)**	222,415	165,920
Two-for-one stock split effective June 3, 2005	**—**	—	92,215,239
All other	**(588)**	—	(3,265)
At end of year	**189,714,149**	187,572,200	185,946,678

On May 11, 2005, the Company's Board of Directors approved a two-for-one stock split effective as of June 3, 2005 by way of a dividend of one share of stock for each share held to all shareholders of record at the close of business on May 20, 2005. The total number of authorized Common shares and shares held in the treasury, and the par value thereof, was unchanged by the split.

Note U – 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 Wal-Mart 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-32, Certain Long-Lived Assets at December 31 exclude investments, noncurrent receivables, deferred tax assets and goodwill and other intangible assets.

Excise taxes on petroleum products of $2,070,077,000, $1,741,707,000 and $1,459,713,000 for the years 2007, 2006 and 2005, 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 (Millions of dollars)	Exploration and Production						
	U.S.	Canada	U.K.	Malaysia	Ecuador	Other	Total
Year ended December 31, 2007							
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**	**560.8**	**31.8**	**629.1**	**40.1**	**129.5**	**1,634.4**
Total assets at year-end	**1,130.2**	**2,327.8**	**198.9**	**2,110.2**	**130.7**	**431.6**	**6,329.4**
Year ended December 31, 2006							
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
Year ended December 31, 2005							
Segment income (loss) from continuing operations	$ 385.5	310.1	79.9	(4.7)	38.1	(58.9)	750.0
Revenues from external customers	849.0	721.6	180.7	234.0	116.6	4.4	2,106.3
Intersegment revenues	—	59.7	—	—	—	—	59.7
Interest income	—	—	—	—	—	—	—
Interest expense, net of capitalization	—	—	—	—	—	—	—
Income tax expense (benefit)	204.4	155.9	47.7	45.1	27.7	.7	481.5
Significant noncash charges (credits)							
Depreciation, depletion, amortization	87.2	134.2	25.0	48.9	23.5	.3	319.1
Accretion of asset retirement obligations	3.3	4.0	1.6	.2	—	.5	9.6
Amortization of undeveloped leases	18.2	3.1	—	—	—	1.5	22.8
Deferred and noncurrent income taxes	25.7	(29.8)	(4.0)	9.5	—	—	1.4
Additions to property, plant, equipment	142.0	263.4	21.6	374.4	23.9	57.0	882.3
Total assets at year-end	896.4	1,556.5	194.6	844.7	134.4	77.5	3,704.1

Geographic Information (Millions of dollars)	Certain Long-Lived Assets at December 31						
	U.S.	Canada	U.K.	Malaysia	Ecuador	Other	Total
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
2005	1,725.3	1,425.2	327.6	734.6	93.9	76.1	4,382.7

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Segment Information (Continued) *(Millions of dollars)*	Refining and Marketing North America	U.K.	Total	Corp. & Other	Consolidated
Year ended December 31, 2007					
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**	**250.7**	**572.4**	**4.2**	**2,211.0**
Total assets at year-end	**2,378.4**	**1,024.5**	**3,402.9**	**803.5**	**10,535.8**
Year ended December 31, 2006					
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
Year ended December 31, 2005					
Segment income (loss) from continuing operations	$ 91.1	40.5	131.6	(35.5)	846.1
Revenues from external customers	8,844.6	904.5	9,749.1	21.7	11,877.1
Intersegment revenues	—	—	—	—	59.7
Interest income	—	—	—	21.5	21.5
Interest expense, net of capitalization	—	—	—	8.8	8.8
Income tax expense (benefit)	52.7	20.3	73.0	(15.6)	538.9
Significant noncash charges (credits)					
Depreciation, depletion, amortization	64.3	10.6	74.9	2.9	396.9
Accretion of asset retirement obligations	.1	—	.1	—	9.7
Amortization of undeveloped leases	—	—	—	—	22.8
Deferred and noncurrent income taxes	12.4	4.9	17.3	26.8	45.5
Additions to property, plant, equipment	123.3	79.1	202.4	35.5	1,120.2
Total assets at year-end	1,627.6	409.5	2,037.1	669.2	6,410.4

Geographic Information *(Millions of dollars)*	Revenues from External Customers for the Year U.S.	U.K.	Canada	Malaysia	Ecuador	Other	Total
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
2005	9,661.9	1,100.3	759.7	234.0	116.6	4.6	11,877.1

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 7.4 million barrels at December 31, 2007. 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 82.6 million barrels and 424.0 billion cubic feet, respectively, at December 31, 2007.

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

At December 31, 2007, proved reserves are included for several fields where development projects are ongoing, including one field in the Gulf of Mexico, 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.

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, 2007.

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Schedule 1 – Estimated Net Proved Oil Reserves

(Millions of barrels)	United States	Canada	United Kingdom	Malaysia	Ecuador	Total
Proved						
December 31, 2004	66.0	41.2	24.3	54.0	17.3	202.8
Revisions of previous estimates	(6.4)	3.0	1.9	(1.5)	2.1	(.9)
Improved recovery	—	2.9	—	—	—	2.9
Extensions and discoveries	.1	12.0	—	—	—	12.1
Production	(9.4)	(12.9)	(2.9)	(5.0)	(2.9)	(33.1)
Sales of properties	(1.4)	(.4)	—	—	—	(1.8)
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**
Proved Developed						
December 31, 2004	31.3	32.5	19.8	12.4	7.9	103.9
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**

Schedule 2 – Estimated Net Proved Natural Gas Reserves

(Billions of cubic feet)	United States	Canada	United Kingdom	Malaysia	Total
Proved					
December 31, 2004	220.5	23.6	24.7	—	268.8
Revisions of previous estimates	.1	(.4)	6.8	—	6.5
Extensions and discoveries	16.5	5.2	—	—	21.7
Production	(25.7)	(3.8)	(3.4)	—	(32.9)
Sales of properties	(33.3)	—	—	—	(33.3)
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
Proved Developed					
December 31, 2004	136.6	22.2	24.0	—	182.8
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**

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-40.

Synthetic Oil Proved Reserves
(Millions of barrels)

December 31, 2004	138.0
December 31, 2005	133.1
December 31, 2006	125.9
December 31, 2007	**128.4**

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Schedule 3 – Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

(Millions of dollars)	United States	Canada[1]	United Kingdom	Malaysia	Ecuador	Other	Total
Year Ended December 31, 2007							
Property acquisition costs							
Unproved	**$ 23.4**	**399.2**	**—**	**—**	**—**	**—**	**422.6**
Proved	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Total acquisition costs	**23.4**	**399.2**	**—**	**—**	**—**	**—**	**422.6**
Exploration costs[2]	**112.8**	**31.1**	**.8**	**43.9**	**.3**	**19.3**	**208.2**
Development costs[2]	**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**
Year Ended December 31, 2006							
Property acquisition costs							
Unproved	$ 13.0	.9	—	—	—	—	13.9
Proved	—	—	—	—	—	—	—
Total acquisition costs	13.0	.9	—	—	—	—	13.9
Exploration costs[2]	119.2	4.9	—	185.6	1.5	26.8	338.0
Development costs[2]	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
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
Year Ended December 31, 2005							
Property acquisition costs							
Unproved	$ 32.5	2.0	—	—	—	—	34.5
Proved	—	.2	—	—	—	—	.2
Total acquisition costs	32.5	2.2	—	—	—	—	34.7
Exploration costs[2]	79.7	7.2	4.1	209.3	1.0	106.4	407.7
Development costs[2]	84.2	154.1	22.0	268.9	23.9	1.0	554.1
Total costs incurred	196.4	163.5	26.1	478.2	24.9	107.4	996.5
Charged to expense							
Dry hole expense	21.4	(1.0)	3.8	55.8	1.0	45.0	126.0
Geophysical and other costs	23.8	8.2	.3	45.9	—	5.4	83.6
Total charged to expense	45.2	7.2	4.1	101.7	1.0	50.4	209.6
Property additions	$151.2	156.3	22.0	376.5	23.9	57.0	786.9

[1] Excludes property additions for the Company's 5% interest in synthetic oil operations in Canada of $23.6 million in 2007, $42.2 million in 2006 and $112.9 million in 2005.

[2] Includes non-cash asset retirement costs as follows:

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
2005							
Exploration costs	$ 1.1	—	—	2.1	—	—	3.2
Development costs	8.1	5.8	.4	—	—	—	14.3
	$ 9.2	5.8	.4	2.1	—	—	17.5

Schedule 4 – Results of Operations for Oil and Gas Producing Activities

(Millions of dollars)	United States	Canada	United Kingdom	Malaysia	Ecuador	Other	Subtotal	Synthetic Oil – Canada	Total
Year Ended December 31, 2007									
Revenues									
Crude oil and natural gas liquids									
Sales to unaffiliated enterprises	**$310.8**	**559.3**	**129.4**	**436.0**	**126.1**	**—**	**1,561.6**	**290.4**	**1,852.0**
Transfers to consolidated operations	**—**	**69.3**	**.1**	**—**	**—**	**—**	**69.4**	**61.0**	**130.4**
Natural gas									
Sales to unaffiliated enterprises	**121.7**	**23.0**	**16.6**	**—**	**—**	**—**	**161.3**	**—**	**161.3**
Total oil and gas revenues	**432.5**	**651.6**	**146.1**	**436.0**	**126.1**	**—**	**1,792.3**	**351.4**	**2,143.7**
Other operating revenues	**(2.7)**	**.3**	**.6**	**(.3)**	**—**	**4.5**	**2.4**	**—**	**2.4**
Total revenues	**429.8**	**651.9**	**146.7**	**435.7**	**126.1**	**4.5**	**1,794.7**	**351.4**	**2,146.1**
Costs and expenses									
Production expenses	**80.4**	**104.4**	**23.5**	**73.7**	**36.6**	**—**	**318.6**	**144.4**	**463.0**
Exploration costs charged to expense	**76.1**	**40.5**	**.8**	**33.1**	**.3**	**19.1**	**169.9**	**—**	**169.9**
Undeveloped lease amortization	**17.5**	**14.2**	**—**	**—**	**—**	**1.5**	**33.2**	**—**	**33.2**
Depreciation, depletion and amortization	**74.5**	**157.3**	**20.7**	**57.9**	**39.2**	**.7**	**350.3**	**26.5**	**376.8**
Accretion of asset retirement obligations	**4.0**	**4.8**	**2.0**	**4.0**	**—**	**.6**	**15.4**	**.7**	**16.1**
Impairment of long-lived assets	**2.6**	**—**	**—**	**—**	**—**	**—**	**2.6**	**—**	**2.6**
Selling and general expenses	**31.4**	**17.7**	**3.7**	**9.0**	**.8**	**17.5**	**80.1**	**.8**	**80.9**
Minority interest	**—**	**(.5)**	**—**	**—**	**—**	**—**	**(.5)**	**—**	**(.5)**
Total costs and expenses	**286.5**	**338.4**	**50.7**	**177.7**	**76.9**	**39.4**	**969.6**	**172.4**	**1,142.0**
	143.3	**313.5**	**96.0**	**258.0**	**49.2**	**(34.9)**	**825.1**	**179.0**	**1,004.1**
Income tax expense	**45.1**	**79.7**	**48.4**	**109.8**	**20.7**	**.7**	**304.4**	**42.6**	**347.0**
Results of operations*	**$ 98.2**	**233.8**	**47.6**	**148.2**	**28.5**	**(35.6)**	**520.7**	**136.4**	**657.1**
Year Ended December 31, 2006									
Revenues									
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
Costs and 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.

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Schedule 4 – Results of Operations for Oil and Gas Producing Activities (Contd.)

(Millions of dollars)	United States	Canada	United Kingdom	Malaysia	Ecuador	Other	Subtotal	Synthetic Oil – Canada	Total
Year Ended December 31, 2005									
Revenues									
Crude oil and natural gas liquids									
Sales to unaffiliated enterprises	$448.8	471.3	159.8	232.9	116.6	—	1,429.4	213.4	1,642.8
Transfers to consolidated operations	—	48.4	—	—	—	—	48.4	11.3	59.7
Natural gas									
Sales to unaffiliated enterprises	216.6	29.7	19.9	—	—	—	266.2	—	266.2
Total oil and gas revenues	665.4	549.4	179.7	232.9	116.6	—	1,744.0	224.7	1,968.7
Other operating revenues	183.6	7.2	1.0	1.1	—	4.4	197.3	—	197.3
Total revenues	849.0	556.6	180.7	234.0	116.6	4.4	1,941.3	224.7	2,166.0
Costs and expenses									
Production expenses	70.8	58.7	18.4	35.2	25.3	—	208.4	94.2	302.6
Exploration costs charged to expense	45.2	7.2	4.1	101.7	1.0	50.4	209.6	—	209.6
Undeveloped lease amortization	18.2	3.1	—	—	—	1.5	22.8	—	22.8
Depreciation, depletion and amortization	87.2	121.4	25.0	48.9	23.5	.3	306.3	12.8	319.1
Accretion of asset retirement obligations	3.3	3.5	1.6	.2	—	.5	9.1	.5	9.6
Net costs associated with hurricanes	12.4	3.4	1.2	.2	—	—	17.2	1.6	18.8
Selling and general expenses	22.0	8.2	2.8	7.4	1.0	9.9	51.3	.7	52.0
Total costs and expenses	259.1	205.5	53.1	193.6	50.8	62.6	824.7	109.8	934.5
	589.9	351.1	127.6	40.4	65.8	(58.2)	1,116.6	114.9	1,231.5
Income tax expense	204.4	118.6	47.7	45.1	27.7	.7	444.2	37.3	481.5
Results of operations*	$385.5	232.5	79.9	(4.7)	38.1	(58.9)	672.4	77.6	750.0

* Excludes corporate overhead, interest and discontinued operations. Income from discontinued operations was $8.6 million in 2005.

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

(Millions of dollars)	United States	Canada*	United Kingdom	Malaysia	Ecuador	Total
December 31, 2007						
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**
December 31, 2006						
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
December 31, 2005						
Future cash inflows	$ 4,453.2	1,890.3	1,494.5	2,198.4	607.7	10,644.1
Future development costs	(235.2)	(33.9)	(39.1)	(314.2)	(39.8)	(662.2)
Future production and abandonment costs	(394.6)	(577.5)	(236.6)	(332.1)	(149.1)	(1,689.9)
Future income taxes	(1,164.1)	(391.8)	(509.9)	(457.1)	(118.3)	(2,641.2)
Future net cash flows	2,659.3	887.1	708.9	1,095.0	300.5	5,650.8
10% annual discount for estimated timing of cash flows	(682.1)	(156.8)	(253.7)	(301.3)	(67.9)	(1,461.8)
Standardized measure of discounted future net cash flows	$ 1,977.2	730.3	455.2	793.7	232.6	4,189.0

* Excludes discounted future net cash flows from synthetic oil of $2,127.6 million at December 31, 2007, $1,096.0 million at December 31, 2006 and $1,201.0 million at December 31, 2005.

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

(Millions of dollars)	2007	2006	2005
Net changes in prices, production costs and development costs	**$ 1,130.6**	(1,948.7)	2,758.8
Sales and transfers of oil and gas produced, net of production costs	**(1,476.1)**	(1,413.2)	(1,732.9)
Net change due to extensions and discoveries	**1,919.6**	1,026.0	406.5
Net change due to purchases and sales of proved reserves	**—**	8.8	(274.0)
Development costs incurred	**936.0**	645.2	520.2
Accretion of discount	**508.8**	613.6	414.0
Revisions of previous quantity estimates	**(121.8)**	20.7	(96.9)
Net change in income taxes	**(946.0)**	379.5	(589.1)
Net increase (decrease)	**1,951.1**	(668.1)	1,406.6
Standardized measure at January 1	**3,520.9**	4,189.0	2,782.4
Standardized measure at December 31	**$ 5,472.0**	3,520.9	4,189.0

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Schedule 6 – Capitalized Costs Relating to Oil and Gas Producing Activities

(Millions of dollars)	United States	Canada	United Kingdom	Malaysia	Ecuador	Other	Subtotal	Synthetic Oil – Canada	Total
December 31, 2007									
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**
December 31, 2006									
Unproved oil and gas properties	$ 192.7	65.6	—	235.5	—	96.2	590.0	—	590.0
Proved oil and gas properties	932.1	1,471.5	437.0	1,126.1	340.9	3.3	4,310.9	758.9	5,069.8
Gross capitalized costs	1,124.8	1,537.1	437.0	1,361.6	340.9	99.5	4,900.9	758.9	5,659.8
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	(54.0)	(14.7)	—	—	—	(7.3)	(76.0)	—	(76.0)
Proved oil and gas properties	(366.3)	(645.9)	(266.1)	(132.8)	(237.7)	(3.3)	(1,652.1)	(122.5)	(1,774.6)
Net capitalized costs	$ 704.5	876.5	170.9	1,228.8	103.2	88.9	3,172.8	636.4	3,809.2

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.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL QUARTERLY INFORMATION (UNAUDITED)

(Millions of dollars except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Year Ended December 31, 2007					
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**
Year Ended December 31, 2006					
Sales and other operating revenues	$ 2,987.1	3,798.0	4,147.7	3,346.5	14,279.3
Income before income taxes	214.8	295.1	384.5	144.0	1,038.4
Net income	116.0	216.2	224.1	88.4	644.7
Income per Common share – basic	0.62	1.16	1.20	0.47	3.46
Income per Common share – diluted	0.61	1.14	1.18	0.47	3.41
Cash dividend per Common share	.1125	.1125	.15	.15	.525
Market price of Common Stock*					
High	59.15	55.86	56.90	54.28	59.15
Low	45.36	47.23	45.90	45.12	45.12

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SCHEDULE II – VALUATION ACCOUNTS AND RESERVES

(Millions of dollars)	Balance at January 1	Charged (Credited) to Expense	Deductions	Other*	Balance at December 31
2007					
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**
2006					
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
2005					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 14.0	1.4	(1.0)	.1	14.5
Deferred tax asset valuation allowance	84.0	67.1	—	—	151.1

* Amounts primarily represent changes in foreign currency exchange rates.

GLOSSARY OF TERMS

3-D 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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES (UNAUDITED)
(THOUSANDS OF DOLLARS)

	Years Ended December 31,				
	2007	2006	2005	2004	2003
Income from continuing operations before income taxes	$1,237,232	1,038,398	1,385,115	810,812	374,851
Distributions (less than) greater than equity in earnings of affiliates	294	(4,065)	(5,514)	(4,225)	(209)
Previously capitalized interest charged to earnings during period	14,585	11,741	15,564	14,065	10,457
Interest and expense on indebtedness	25,612	9,476	8,765	34,064	20,511
Interest portion of rentals*	13,554	14,021	9,397	7,908	9,857
Earnings before provision for taxes and fixed charges	**$1,291,277**	**1,069,571**	**1,413,327**	**862,624**	**415,467**
Interest and expense on indebtedness, excluding capitalized interest	$ 25,612	9,476	8,765	34,064	20,511
Capitalized interest	49,881	43,073	38,539	22,160	37,240
Interest portion of rentals*	13,554	14,021	9,397	7,908	9,857
Total fixed charges	**$ 89,047**	**66,570**	**56,701**	**64,132**	**67,608**
Ratio of earnings to fixed charges	**14.5**	**16.1**	**24.9**	**13.5**	**6.1**

* Calculated as one-third of rentals, which is considered a reasonable approximation of interest factor.

Letter to Shareholders

Claiborne P. Deming
President and Chief Executive Officer

Dear Fellow Shareholders,

I believe very strongly that 2007 will be viewed, especially in the fullness of time, as a pivotal and extraordinarily important year for our Company. The year will not only be identified with a significant individual event (the start-up of production from our Kikeh field (80%) in Malaysia) but also as the year the Company repositioned itself and charted the course for its future. We are in the midst of an intriguing but, more importantly, intense value-creation time, represented, in part, by the following: the start-up of Kikeh; frontier acreage acquisitions offshore Suriname and Australia; a potentially significant natural gas “new play” acquisition in British Columbia; the most successful Gulf of Mexico lease sale for Murphy in recent memory; the Murphy USA property acquisition; and the Milford Haven, Wales refinery purchase. In addition, we sold down the Company’s interest in the Azurite field in West Africa (picking up a “carry” on two exploration wells) and sold out of our position in Berkana Energy Corp., a Canadian junior company.

In brief, the realigned leadership group put in place at the end of 2006 consisting of David Wood, leader of a single worldwide Upstream operating group, and Harvey Doerr, head of worldwide Downstream operations, performed well in their expanded roles. I feel very confident with their leadership reflected by the opportunities already secured under their oversight.

Financial Results A healthy commodity price environment coupled with good execution by both the Upstream and Downstream operating units allowed the Company to turn in its second best year of net income with earnings of $766.5 million ($4.01 per diluted share). Cash flow from operations was $1,740.4 million and we ended the year with a healthy debt to capital employed ratio of 23%.

Exploration and Production Deservedly, Kikeh gets top billing. The start-up of production from this field on August 17, 2007 brought to fruition arguably the most meaningful discovery in the Company’s history. We believe the Kikeh development set a record for a deepwater development by going from discovery to first oil in just five years. Just as importantly, costs were controlled very efficiently during a period of escalating prices. We all owe a debt of gratitude to the first class team led by Roger Jenkins that made this happen.

Secondly, from the sanctioned development projects now in place, production is set to approximately double in the near term from the 2007 average production level of just under 102,000 barrels of oil equivalent per day. This industry leading organic growth is anchored by the Kikeh field, but also importantly from other developments scheduled to commence production beginning in 2008 and 2009, including: Tupper (100%); Sarawak natural gas (85%); Thunder Hawk (37.5%); and Azurite (50%). Also, our Kakap (14%) discovery offshore Sabah, Malaysia was sanctioned in December and will be part of a unitized development operated by another company with first production slated for late 2012.

As planned, 2007 was somewhat quiet on the exploration front. We made two natural gas discoveries in Block H offshore Malaysia, Rotan and Biris (both 80%). These fields provide a solid foundation as we pursue bringing another production center on in this region. Look for us to become much more active on the worldwide exploration front in 2008. Wildcats are planned for deepwater Block K and shallow water Blocks 309 and 311 in Malaysia, both the Mer Profonde Sud and Mer Profonde Nord blocks offshore Republic of Congo, the Gulf of Mexico, and offshore Australia. These prospects tend to be quite large and target both oil and gas. In the Congo, partners will be brought in and will pay disproportionately in order to mitigate risk.

Of considerable importance for the future and as noted at the outset, we were able to quietly position ourselves over the last year into new areas that will enhance an already robust exploration portfolio. Acreage was acquired in two new countries – Suriname and Australia. Block 37 in Suriname (80%) covers about two million acres and was picked up in June. We will be acquiring 3D seismic this year and should drill our first prospect in 2009. In November, we announced the acquisition, subject to government approval, of a 40% working interest and operatorship in permit AC/P36 located in the Browse Basin offshore northwestern Australia. The area covers approximately one million acres and has several quite large structures which are currently being evaluated ahead of drilling in the fourth quarter of 2008.

We were also able to pick up substantial acreage in a more familiar basin – the Gulf of Mexico. Twenty-six deepwater blocks in DeSoto Canyon and Lloyd Ridge were obtained in October's OCS Sale 205. These blocks, 22 of which have never been leased before, will become a focal point in future Gulf of Mexico exploration plans beginning this year and complement our existing Green Canyon acreage position upon which we recently received encouraging preliminary results from a wide-azimuth 3D survey shoot.

Another significant addition during 2007 was the Tupper leases. Located in northeastern British Columbia, this tight gas sands play is part of the Triassic-aged Montney formation. Given our affinity toward high impact exploration, this resource play provides us with needed balance while making us more geographically diverse. The drilling program kicked off in November 2007 and results thus far have been promising. We will concentrate our effort this year on drilling and putting the infrastructure in place to bring first gas to market in the fourth quarter of 2008.

Refining and Marketing Turning to Downstream, 2007 resulted in record setting income for the group of nearly $206 million, approximately 27% of total company-wide net income. Considering the state of our downstream business post-Hurricane Katrina, this magnitude of earnings is certainly welcome. Naturally, more is expected.

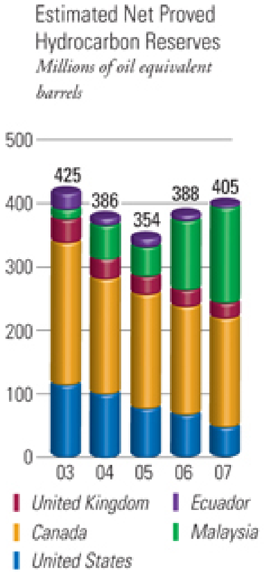
Two distinguishing events occurred in 2007. Firstly, we acquired the real estate underlying most of our existing Murphy USA retail stations, and secondly, we purchased the remaining 70% interest in the Milford Haven, Wales refinery.

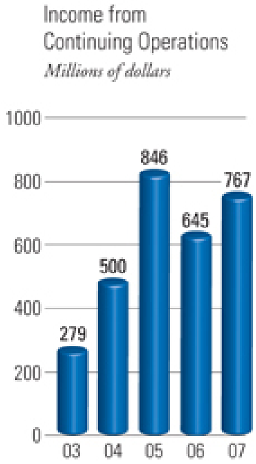
Owning the retail properties as opposed to leasing enhances the sustainability of this "best in class" retail offering. In the process of securing this deal, we were able to close 47 nonstrategic U.S. locations that were not performing as well as the remainder of the sites. In an effort to leverage our brand recognition, we are also in the early stages of implementing a new, larger convenience store model independent of our Wal-Mart Supercenter stronghold. It will be a "new launch" that should quickly gain scale and complement the highly successful Murphy USA format. We exited 2007 with 973 stations in operation and should top the 1,000 station threshold later this year.

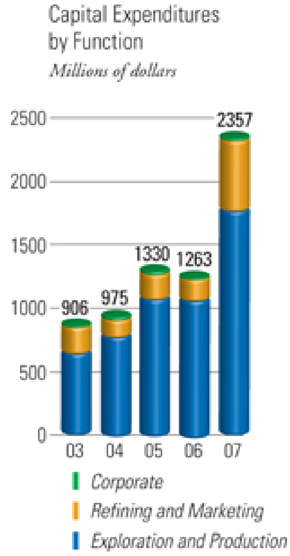
Effective December 1, 2007, for a very attractive price, we became sole owner and operator of the Milford Haven refinery in which we previously held a 30% stake. Integration of this facility into our portfolio adds important diversity to our Downstream business and should be immediately accretive to earnings and cash flow. Having been a partner in the facility for over 26 years, we have experience in the local market and should be able to capture synergies afforded by having a focused, unitary ownership structure. While this acquisition makes us "long" on gasoline in the U.K., our retail network will look to expand and we will explore potential arbitrage opportunities to the United States.

On the United States refining front, much emphasis continues to be placed upon operating reliably. I am happy to say that Meraux's operational performance during the final quarter of 2007 was excellent. Our Superior, Wisconsin refinery once again proved to be a steady performer eclipsing the profit record set in 2006.

Often not mentioned but critically important, our midstream business was strengthened as well in 2007 with the opening of a new terminal facility near Jonesboro, Arkansas. This terminal services a three-state region in the heartland of America. In 2008, we plan to equip all 12 of our company-owned U.S. terminals with ethanol blending capabilities.







Closing Thoughts History tells us that high commodity prices are destined to retreat and low commodity prices are destined to climb. As an organization, it is imperative that we position ourselves wisely in the event of a downturn in the overall economy or commodity prices, while still taking the steps necessary to ensure future success in either pricing environment.

Quite candidly, I believe Murphy Oil is stronger today than ever and properly aligned to create value for our shareholders. Murphy is fortunate to have an extraordinary array of talented individuals at all levels of our organization that not only have the foresight necessary to chart the course but the willingness to roll up their sleeves and get there.

As our shareholders, we work for you and your continued support is greatly appreciated. In 2007 we took steps to chart the course of Murphy Oil; now it is time to make it happen. That is exactly what we are doing.

Claiborne P. Deming
President and Chief Executive Officer

February 15, 2008
El Dorado, Arkansas

Financial and Operating Highlights

(Thousands of dollars except per share data)	2007	2006	% Change 2007–2006	2005	% Change 2006–2005
For the Year					
Revenues	$18,439,098	$14,307,387	29%	$11,877,151	20%
Net income	766,529	644,669	19%	854,742	-25%
Income from continuing operations	766,529	644,669	19%	846,193	-24%
Cash dividends paid	127,353	98,162	30%	83,198	18%
Capital expenditures [1]	2,357,347	1,262,539	87%	1,329,831	-5%
Net cash provided by operating activities	1,740,420	975,478	78%	1,248,931	-22%
Average common shares outstanding – diluted (thousands)	191,141	189,158	1%	187,889	1%
At End of Year					
Working capital	$ 777,530	$ 795,986	-2%	$ 551,938	44%
Net property, plant and equipment	7,109,822	5,106,282	39%	4,374,229	17%
Total assets	10,535,849	7,483,161	41%	6,410,396	17%
Long-term debt	1,516,156	840,275	80%	609,574	38%
Stockholders’ equity	5,066,174	4,121,273	23%	3,522,070	17%
Per Share of Common Stock					
Net income – diluted	$ 4.01	$ 3.41	18%	$ 4.55	-25%
Income from continuing operations – diluted	4.01	3.41	18%	4.50	-24%
Cash dividends paid	.675	.525	29%	.45	17%
Stockholders’ equity	26.70	21.97	22%	18.94	16%
Net Crude Oil and Gas Liquids Produced – barrels per day [1]	91,522	87,817	4%	101,349	-13%
United States	12,989	21,112	-38%	25,897	-18%
Canada	43,939	39,653	11%	46,086	-14%
Other International	34,594	27,052	28%	29,366	-8%
Net Natural Gas Sold – thousands of cubic feet per day [1]	61,082	75,262	-19%	90,198	-17%
United States	45,139	56,810	-21%	70,452	-19%
Canada	9,922	9,752	2%	10,323	-6%
United Kingdom	6,021	8,700	-31%	9,423	-8%
Crude Oil Refined – barrels per day	175,183	119,231	47%	135,122	-12%
North America	139,183	89,195	56%	108,139	-18%
United Kingdom	36,000	30,036	20%	26,983	-11%
Petroleum Products Sold – barrels per day	457,770	385,271	19%	358,255	8%
North America	416,668	350,601	19%	322,714	9%
United Kingdom	41,102	34,670	19%	35,541	-2%
Stockholder and Employee Data					
Common shares outstanding (thousands) [2]	189,714	187,572	1%	185,947	1%
Number of stockholders of record [2]	2,655	2,758	-4%	2,847	-3%
Number of employees [2]	7,539	7,296	3%	6,248	17%
Average number of employees	7,340	7,019	5%	6,127	15%

1 From continuing operations.

2 At December 31.

Exploration and Production Statistical Summary

	2007	2006	2005	2004	2003	2002	2001
Net crude oil, condensate and natural gas liquids production – barrels per day							
United States	12,989	21,112	25,897	19,314	4,526	4,128	4,752
Canada – light	596	443	563	650	1,213	1,567	2,521
heavy	11,524	12,613	11,806	5,838	4,705	3,609	4,521
offshore	18,871	14,896	23,124	25,407	28,534	24,037	9,535
synthetic	12,948	11,701	10,593	11,794	10,483	11,362	10,479
United Kingdom	5,281	7,146	7,992	11,011	14,686	18,302	20,214
Malaysia	20,367	11,298	13,503	11,885	7,301	—	—
Ecuador	8,946	8,608	7,871	7,735	5,172	4,544	5,319
Continuing operations	91,522	87,817	101,349	93,634	76,620	67,549	57,341
Discontinued operations	—	—	—	3,106	6,832	8,821	10,014
Total liquids produced	91,522	87,817	101,349	96,740	83,452	76,370	67,355
Net crude oil, condensate and natural gas liquids sold – barrels per day							
United States	12,989	21,112	25,897	19,314	4,526	4,128	4,752
Canada – light	596	443	563	650	1,213	1,567	2,521
heavy	11,524	12,613	11,806	5,838	4,705	3,609	4,521
offshore	18,839	15,360	22,443	26,306	28,542	23,935	9,862
synthetic	12,948	11,701	10,593	11,794	10,483	11,362	10,479
United Kingdom	5,218	6,678	8,303	10,924	14,722	18,358	20,354
Malaysia	16,018	11,986	13,818	11,020	7,235	—	—
Ecuador	9,470	10,349	9,821	3,414	4,997	4,293	5,381
Continuing operations	87,602	90,242	103,244	89,260	76,423	67,252	57,870
Discontinued operations	—	—	—	3,106	6,832	8,821	10,014
Total liquids sold	87,602	90,242	103,244	92,366	83,255	76,073	67,884
Net natural gas sold – thousands of cubic feet per day							
United States	45,139	56,810	70,452	88,621	82,281	88,067	112,616
Canada	9,922	9,752	10,323	13,972	19,946	12,709	25,701
United Kingdom	6,021	8,700	9,423	6,859	9,564	6,973	13,125
Continuing operations	61,082	75,262	90,198	109,452	111,791	107,749	151,442
Discontinued operations	—	—	—	30,760	103,543	189,182	129,793
Total natural gas sold	61,082	75,262	90,198	140,212	215,334	296,931	281,235
Net hydrocarbons produced – equivalent barrels[1,2] per day	101,702	100,361	116,382	120,109	119,341	125,859	114,228
Estimated net hydrocarbon reserves – million equivalent barrels[1,2,3]	405.1	388.3	353.6	385.6	425.5	455.3	501.2
Weighted average sales prices[4]							
Crude oil, condensate and NGL – dollars per barrel							
United States	$ 65.57	57.30	47.48	35.35	24.22	24.25	24.92
Canada[5] – light	50.98	50.45	44.27	32.96	26.02	20.38	21.75
heavy	32.84	25.87	21.30	20.26	12.36	16.83	11.21
offshore	69.83	62.55	51.37	36.60	27.08	25.36	23.77
synthetic	74.35	63.23	58.12	40.35	24.97	25.64	25.04
United Kingdom	68.38	64.30	52.83	36.82	29.59	24.39	24.44
Malaysia[6]	74.58	51.78	46.16	41.35	29.42	—	—
Ecuador[7]	36.47	33.79	32.54	24.78	22.99	19.64	17.00
Natural gas – dollars per thousand cubic feet							
United States	7.38	7.76	8.52	6.45	5.29	3.37	4.64
Canada[5]	6.34	6.49	7.88	5.64	4.47	2.59	3.54
United Kingdom[5]	7.54	7.34	5.80	4.52	3.50	2.76	2.52

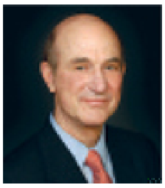
1 Natural gas converted at a 6:1 ratio.
2 Includes synthetic oil.
3 At December 31.
4 Includes intracompany transfers at market prices.
5 U.S. dollar equivalent.
6 Prices in 2007–2005 are net of payments under the terms of the production sharing contracts for Blocks SK 309 and K.
7 Includes prices attained in 2006 and 2005 for recoupment of a portion of 2004 Block 16 crude oil production formerly owed to the Company. The prices in 2007 and 2006 are adversely affected by revenue sharing with the Ecuadorian government beginning in April 2006 and further increased in October 2007.

Refining and Marketing Statistical Summary

	2007	2006	2005	2004	2003	2002	2001
Refining							
Crude capacity* of refineries – barrels per stream day	268,000	192,400	192,400	192,400	192,400	167,400	167,400
Refinery inputs – barrels per day							
Crude – Meraux, Louisiana	106,446	55,129	73,371	101,644	60,403	83,721	104,345
Superior, Wisconsin	32,737	34,066	34,768	31,598	30,466	30,468	35,869
Milford Haven, Wales	36,000	30,036	26,983	31,033	28,412	29,640	26,985
Other feedstocks	10,805	6,423	9,131	12,170	10,113	11,013	9,901
Total inputs	185,988	125,654	144,253	176,445	129,394	154,842	177,100
Refinery yields – barrels per day							
Gasoline	74,395	48,314	54,869	68,663	52,162	63,409	73,217
Kerosine	5,371	5,067	7,805	7,734	6,568	9,446	12,874
Diesel and home heating oils	67,111	42,137	48,535	66,225	41,277	48,344	52,660
Residuals	18,910	15,244	18,231	17,445	14,595	16,589	20,530
Asphalt, LPG and other	17,546	12,855	13,268	14,693	11,986	12,651	13,467
Fuel and loss	2,655	2,037	1,545	1,685	2,806	4,403	4,352
Total yields	185,988	125,654	144,253	176,445	129,394	154,842	177,100
Average cost of crude inputs to refineries – dollars per barrel							
North America	$ 69.40	59.54	49.73	40.00	29.79	24.76	23.44
United Kingdom	81.53	66.66	56.15	39.60	30.24	25.83	24.86
Marketing							
Products sold – barrels per day							
North America – Gasoline	298,833	266,353	233,191	207,786	162,911	112,281	96,597
Kerosine	1,685	2,269	5,671	4,811	4,388	5,818	9,621
Diesel and home heating oils	91,344	62,196	60,228	66,648	43,373	35,995	41,064
Residuals	15,422	11,696	15,330	13,699	10,972	13,759	17,308
Asphalt, LPG and other	9,384	8,087	8,294	8,857	8,232	8,574	9,666
	416,668	350,601	322,714	301,801	229,876	176,427	174,256
United Kingdom – Gasoline	14,356	12,425	12,739	11,435	12,101	12,058	11,058
Kerosine	4,020	3,619	2,410	2,756	2,526	2,685	2,547
Diesel and home heating oils	14,785	11,803	14,910	14,649	13,506	14,574	11,798
Residuals	3,728	3,825	3,242	4,062	3,816	3,127	3,538
LPG and other	4,213	2,998	2,240	4,205	3,103	1,760	2,121
	41,102	34,670	35,541	37,107	35,052	34,204	31,062
Total products sold	457,770	385,271	358,255	338,908	264,928	210,631	205,318
Branded retail outlets*							
North America – Murphy USA	973	987	864	752	623	506	387
Other	153	177	337	375	371	408	428
Total	1,126	1,164	1,201	1,127	994	914	815
United Kingdom	389	402	412	358	384	416	411

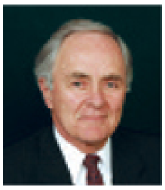
* At December 31.

In 2007, Murphy continued to improve its high-volume Murphy USA brand by growing total fuel sales volumes by 9%.



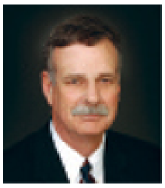
William C. Nolan, Jr.
Partner, Nolan & Alderson, Attorneys,
El Dorado, Arkansas.
Director since 1977.
Chairman of the Board and the Executive Committee, ex-officio member of all other committees

Claiborne P. Deming
President and Chief Executive Officer,
Murphy Oil Corporation,
El Dorado, Arkansas.
Director since 1993.
Committees: Executive

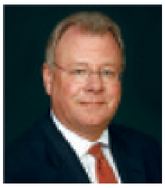


Frank W. Blue
Attorney, Santa Barbara, California.
Director since 2003.
Committees: Audit; Nominating and Governance

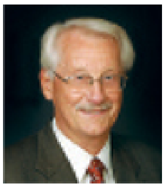
Robert A. Hermes
Chairman of the Board, Retired,
Purvin & Gertz, Inc., Houston, Texas.
Director since 1999.
Committees: Executive; Nominating and Governance (Chairman);
Public Policy and Environmental



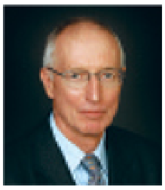
James V. Kelley
President and Chief Operating Officer,
BancorpSouth, Inc., Tupelo, Mississippi.
Director since 2006.
Committees: Audit; Executive Compensation



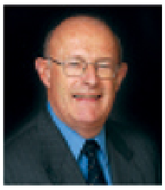
R. Madison Murphy
Managing Member, Murphy Family Management, LLC,
El Dorado, Arkansas.
Director since 1993; Chairman from 1994–2002.
Committees: Executive; Audit (Chairman)



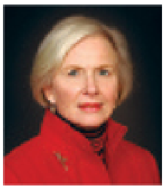
Ivar B. Ramberg
Executive Officer, Ramberg Consulting AS,
Osteraas, Norway.
Director since 2003.
Committees: Nominating and Governance; Public Policy and Environmental



Neal E. Schmale
President and Chief Operating Officer,
Sempra Energy, San Diego, California.
Director since 2004.
Committees: Audit (Financial Expert); Executive Compensation



David J. H. Smith
Chief Executive Officer, Retired,
Whatman plc, Maidstone, Kent, England.
Director since 2001.
Committees: Executive Compensation (Chairman);
Public Policy and Environmental



Caroline G. Theus
President, Keller Enterprises, LLC, and President,
Inglewood Land and Development Co.,
Alexandria, Louisiana.
Director since 1985.
Committees: Executive; Public Policy and Environmental (Chairman)

Murphy Exploration & Production Company
Engages in worldwide crude oil and natural gas exploration and production.

16290 Katy Freeway
Suite 600
Houston, TX 77094
(281) 675-9000

David M. Wood
President

Roger W. Jenkins
Senior Vice President, North America

Steven A. Cossé
Vice President and General Counsel

Mindy K. West
Vice President and Treasurer

John W. Eckart
Vice President and Controller

Walter K. Compton
Secretary

Murphy Oil Company Ltd.
Engages in crude oil and natural gas exploration and production, and extraction and sale of synthetic crude oil.

1700-555-4th Avenue SW
Calgary, Alberta T2P 3E7
(403) 294-8000

Mailing Address:
P.O. Box 2721, Station M
Calgary, Alberta T2P 3Y3
Canada

Steve C. Crosby
President

W. Patrick Olson
Vice President, Production

Mindy K. West
Vice President and Treasurer

Heather J. Jones
Controller

Georg R. McKay
Secretary

Murphy Oil USA, Inc.
Engages in refining and marketing of petroleum products in the United States.

200 Peach Street
El Dorado, Arkansas 71730
(870) 862-6411

Mailing Address:
P.O. Box 7000
El Dorado, Arkansas
71731-7000

Harvey Doerr
President

Charles A. Ganus
Senior Vice President, Marketing and President, Murphy USA Marketing Company

Gary R. Bates
Vice President, Supply and Transportation

Ernest C. Cagle
Vice President, Manufacturing

John D. Edmunds
Vice President, Engineering

Henry J. Heithaus
Vice President, Retail Marketing

Steven A. Cossé
Vice President and General Counsel

Mindy K. West
Vice President and Treasurer

John W. Eckart
Vice President and Controller

Walter K. Compton
Secretary

Murco Petroleum Limited
Engages in refining and marketing of petroleum products in the United Kingdom.

4 Beaconsfield Road
St. Albans, Hertfordshire
AL1 3RH, England
44-1727-892-400

Stephen R. Wylie
Managing Director

Jeremy Clarke
Marketing Director

Thomas McKinlay
Supply Director

Simon V. Rhodes
Financial Director

Patricia E. Haylock
Secretary

Corporate Information

Corporate Office

200 Peach Street
P.O. Box 7000
El Dorado, Arkansas 71731-7000
(870) 862-6411

Stock Exchange Listings

Trading Symbol: MUR
New York Stock Exchange

Transfer Agent and Registrar

Computershare Investor Services, L.L.C.
2 North LaSalle St.
Chicago, Illinois 60602
Toll-free (888) 239-5303
Local Chicago (312) 360-5303

Electronic Payment of Dividends

Shareholders may have dividends deposited directly into their bank accounts by electronic funds transfer. Authorization forms may be obtained from:

Computershare Investor Services, L.L.C.
2 North LaSalle St.
Chicago, Illinois 60602
Toll-free (888) 239-5303
Local Chicago (312) 360-5303

Annual Meeting

The annual meeting of the Company's shareholders will be held at 10:00 a.m. on May 14, 2008, at the South Arkansas Arts Center, 110 East 5th Street, El Dorado, Arkansas. A formal notice of the meeting, together with a proxy statement and proxy form, will be provided to all shareholders.

E-mail Address

murphyoil@murphyoilcorp.com

www.murphyoilcorp.com

Murphy Oil's website provides frequently updated information about the Company and its operations, including:

- News releases
- Annual report
- Quarterly reports
- Live webcasts of quarterly conference calls
- Links to the Company's SEC filings
- Stock quotes
- Profiles of the Company's operations
- On-line stock investment accounts
- Murphy USA station locator

Inquiries

Inquiries regarding shareholder account matters should be addressed to:

Walter K. Compton
Secretary
Murphy Oil Corporation
P.O. Box 7000
El Dorado, Arkansas 71731-7000

Members of the financial community should direct their inquiries to:

Dory J. Stiles
Manager of Investor Relations
Murphy Oil Corporation
P.O. Box 7000
El Dorado, Arkansas 71731-7000
(870) 864-6496

Certifications

The Company has filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 regarding the quality of our public disclosures as Exhibits 31.1 and 31.2 to our annual report on Form 10-K for the fiscal year ended December 31, 2007. In 2007 after our annual meeting of stockholders, the Company filed with the New York Stock Exchange the CEO certification regarding its compliance with the NYSE corporate governance listing standards as required by NYSE Rule 303A.12(a).

Executive Officers

Claiborne P. Deming

President and Chief Executive Officer since October 1994 and Director and Member of the Executive Committee since 1993.

Steven A. Cossé

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

Executive Vice President and President of Murphy Oil USA, Inc. since January 2007. Mr. Doerr served as President of Murphy Oil Company Ltd. from September 1997 through December 2006.

David M. Wood

Executive Vice President and President of Murphy Exploration & Production Company since January 2007. Mr. Wood served as President of Murphy Exploration & Production Company-International from March 2003 through December 2006 and was Senior Vice President of Frontier Exploration & Production from April 1999 through February 2003.

Kevin G. Fitzgerald

Senior Vice President and Chief Financial Officer since January 2007. Mr. Fitzgerald was Treasurer from July 2001 through December 2006 and Director of Investor Relations from 1996 through June 2001.

Bill H. Stobaugh

Senior Vice President since February 2005. Mr. Stobaugh joined the Company as Vice President in 1995.

Mindy K. West

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

John W. Eckart

Vice President and Controller since January 2007. Mr. Eckart has been Controller since March 2000.

Walter K. Compton

Secretary since December 1996.

MURPHY OIL CORPORATION

SUBSIDIARIES OF THE REGISTRANT AS OF DECEMBER 31, 2007

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
Murphy Oil Corporation (REGISTRANT)		
A. Caledonia Land Company	Delaware	100.0
B. El Dorado Engineering Inc.	Delaware	100.0
1. El Dorado Contractors Inc.	Delaware	100.0
C. Marine Land Company	Delaware	100.0
D. Murphy Eastern Oil Company	Delaware	100.0
E. Murphy Exploration & Production Company	Delaware	100.0
1. Mentor Holding Corporation	Delaware	100.0
a. Mentor Excess and Surplus Lines Insurance Company	Delaware	100.0
b. MIRC Corporation	Louisiana	100.0
2. Murphy Building Corporation	Delaware	100.0
3. Murphy Exploration & Production Company – International	Delaware	100.0
a. Canam Offshore Limited	Bahamas	100.0
(1) Murphy Ecuador Oil Company Ltd.	Bermuda	100.0
(2) Murphy Peninsular Malaysia Oil Co., Ltd.	Bahamas	100.0
(3) Murphy Sabah Oil Co., Ltd.	Bahamas	100.0
(4) Murphy Sarawak Oil Co., Ltd.	Bahamas	100.0
b. El Dorado Exploration, S.A.	Delaware	100.0
c. Murphy Australia Oil Pty. Ltd.	Western Australia	100.0
d. Murphy Brazil Exploracao e Producao de Petroleo e Gas Ltda. (see company g.(1) below)	Brazil	90.0
e. Murphy Exploration (Alaska), Inc.	Delaware	100.0
f. Murphy Italy Oil Company	Delaware	100.0
g. Murphy Overseas Ventures Inc.	Delaware	100.0
(1) Murphy Brazil Exploracao e Producao de Petroleo e Gas Ltda. (see company d. above)	Brazil	10.0
h. Murphy Somalia Oil Company	Delaware	100.0
i. Murphy-Spain Oil Company	Delaware	100.0
j. Murphy Suriname Oil Company Ltd.	Bahamas	100.0
k. Murphy West Africa, Ltd.	Bahamas	100.0
l. Ocean Exploration Company	Delaware	100.0
m. Odeco Italy Oil Company	Delaware	100.0
4. Murphy Exploration & Production Company – USA	Delaware	100.0
5. Odeco Drilling (UK) Limited	England	100.0
6. Sub Sea Offshore (M) Sdn. Bhd.	Malaysia	60.0
F. Murphy Oil Company Ltd.	Canada	100.0
1. Murphy Atlantic Offshore Finance Company Ltd.	Canada	100.0
2. Murphy Atlantic Offshore Oil Company Ltd.	Canada	100.0
3. Murphy Canada Exploration Company	NSULCo.*	100.0
a. Environmental Technologies Inc.	Canada	52.0
(1) Eastern Canadian Coal Gas Venture Ltd.	Canada	100.0
b. Berkana Energy Corp.	Canada	77.0
4. Murphy Canada, Ltd.	Canada	100.0
5. Murphy Finance Company	NSULCo.*	100.0
6. Berkana Energy Corp.	Canada	3.0

MURPHY OIL CORPORATION

SUBSIDIARIES OF THE REGISTRANT AS OF DECEMBER 31, 2007 (Contd.)

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
Murphy Oil Corporation (REGISTRANT) – Contd.		
G. Murphy Oil USA, Inc.	Delaware	100.0
1. 864 Beverage, Inc.	Texas	100.0
2. Arkansas Oil Company	Delaware	100.0
3. Murphy Gas Gathering Inc.	Delaware	100.0
4. Murphy Latin America Refining & Marketing, Inc.	Delaware	100.0
5. Murphy LOOP, Inc.	Delaware	100.0
6. Murphy Crude Oil Marketing, Inc.	Delaware	100.0
7. Murphy Oil Trading Company (Eastern)	Delaware	100.0
8. Spur Oil Corporation	Delaware	100.0
9. Superior Crude Trading Company	Delaware	100.0
H. Murphy Realty Inc.	Delaware	100.0
I. Murphy Ventures Corporation	Delaware	100.0
J. New Murphy Oil (UK) Corporation	Delaware	100.0
1. Murphy Petroleum Limited	England	100.0
a. Alnery No. 166 Ltd.	England	100.0
b. H. Hartley (Doncaster) Ltd.	England	100.0
c. Murco Petroleum Limited	England	100.0
(1) European Petroleum Distributors Ltd.	England	100.0

* Denotes Nova Scotia Unlimited Liability Company.

<u>Consent of Independent Registered Public Accounting Firm</u>

The Board of Directors of Murphy Oil Corporation:

We consent to the incorporation by reference in the registration statements (Nos. 2-82818, 2-86749, 2-86760, 333-27407, 333-43030, 333-57806, 333-119733, and 333-142789) on Form S-8 and (Nos. 33-55161 and 333-84547) on Form S-3 of Murphy Oil Corporation of our reports dated February 29, 2008, with respect to the consolidated balance sheets of Murphy Oil Corporation as of December 31, 2007 and 2006, and the related consolidated statements of income, stockholders' equity, cash flows, and comprehensive income for each of the years in the three-year period ended December 31, 2007, and related financial statement schedule, and the effectiveness of internal control over financial reporting as of December 31, 2007, which reports appear in the December 31, 2007 annual report on Form 10-K of Murphy Oil Corporation. Our report refers to changes in the methods of accounting for share-based payments and recognition of defined pension and other postretirement plans in 2006 and to changes in the method of accounting for planned major maintenance activities, uncertain tax positions and measurement of defined pension and other postretirement plans in 2007.

KPMG LLP

Houston, Texas
February 29, 2008

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Claiborne P. Deming, certify that:

1. I have reviewed this annual report on Form 10-K of Murphy Oil Corporation;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this annual report based on such evaluation; and
   d) disclosed in this annual report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 29, 2008

/s/ Claiborne P. Deming
Claiborne P. Deming
President and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Kevin G. Fitzgerald, certify that:

1. I have reviewed this annual report on Form 10-K of Murphy Oil Corporation;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c) evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this annual report based on such evaluation; and

    d) disclosed in this annual report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 29, 2008

/s/ Kevin G. Fitzgerald
Kevin G. Fitzgerald
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 32

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Murphy Oil Corporation (the "Company") on Form 10-K for the period ended December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), we, Claiborne P. Deming and Kevin G. Fitzgerald, Principal Executive Officer and Principal Financial Officer, respectively, of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to our knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 29, 2008

/s/ Claiborne P. Deming
Claiborne P. Deming
President and Chief Executive Officer
(Principal Executive Officer)

/s/ Kevin G. Fitzgerald
Kevin G. Fitzgerald
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)