UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K/A

(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, 2005

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

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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

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 average price at June 30, 2005, as quoted by the New York Stock Exchange, was approximately $9,760,983,000.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2006 was 186,567,899.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 10, 2006 have been incorporated by reference in Part III herein.

MURPHY OIL CORPORATION

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EXPLANATORY NOTE

The Company is amending its Form 10-K filed on March 15, 2006, so that the disclosure regarding expected 2006 production volume in the fourth paragraph under the "Exploration and Production" heading on page 1 conforms to the expected 2006 production volume disclosure which was previously included elsewhere in the Form 10-K filed on March 15, 2006, and which continues to be included in this Form 10-K/A.

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 North America 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, Ecuador, Malaysia and all other countries. Murphy's refining and marketing activities are subdivided into geographic segments for North America and United Kingdom. Additionally, "Corporate and Other Activities" include interest income, interest expense, foreign exchange effects and overhead not allocated to the segments.

The information appearing in the 2005 Annual Report to Security Holders (2005 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 11 through 21, F-12 and F-13, F-29 through F-37, and F-39 of this Form 10-K report and on pages 6 and 7 of the 2005 Annual Report.

At December 31, 2005, Murphy had 6,248 employees, including 2,261 full-time and 3,987 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.

During 2005, 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 the 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 2005 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 2005 averaged 101,349 barrels per day, an increase of 8% compared to 2004. The increase was primarily due to a full year of production in 2005 at the Front Runner deepwater field in the Gulf of Mexico and higher production of heavy oil in western Canada due to an ongoing development drilling program in the Seal area in Alberta. The Company's worldwide sales volume of natural gas averaged 90 million cubic feet (MMCF) per day in 2005, down 18% from 2004 levels. The lower natural gas sales were due to a disposal of most oil and natural gas properties on the continental shelf of the Gulf of Mexico in mid-2005 and natural gas production temporarily lost in the Gulf of Mexico following Hurricanes Katrina and Rita in the third quarter of 2005.

Total production in 2006 is currently expected to be about 110,000 barrels of oil equivalent per day. Higher synthetic oil production due to the start-up of a new coker unit at Syncrude and higher anticipated production of heavy oil in the Seal area of western Canada due to an ongoing development drilling program are expected to be more than offset by lower production at Terra Nova due to more downtime for repairs, lower volumes allocable to Murphy at the West Patricia field in Malaysia under the production sharing contract, and decline at Front Runner in the deepwater Gulf of Mexico. Natural gas production will be favorably impacted by start-up of the Seventeen Hands field in the deepwater Gulf of Mexico, but other volumes in the deepwater Gulf of Mexico are likely to be lower prior to workovers and volumes in the U.K. are expected to be lower at the Amethyst field.

In the United States, Murphy has production of oil and/or natural gas from six fields operated by the Company and three fields operated by others. Of the total producing fields at December 31, 2005, four are in the deepwater Gulf of Mexico, one is in more shallow waters on the Gulf of Mexico continental shelf, three are onshore in Louisiana and one is the Northstar field in Alaska. 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 operates and owns a 60% interest in the Medusa field, in Mississippi Canyon Blocks 538/582. Medusa produced about 12,400 barrels of oil per day and 12.5 MMCF of gas per day net to the Company in 2005, but was offline for more than three months following Hurricane Katrina. Peak annual net production from Medusa is expected to be about 17,000 barrels of oil equivalent per day and should be achieved in 2006. Murphy operates and holds a 37.5% interest in the Front Runner field in Green Canyon Blocks 338/339 which came on stream in December 2004. Total net daily production at Front Runner in 2005 was 7,500 barrels of oil and 6.4 MMCF of gas. Production in 2006 is expected to decline from 2005 levels as well intervention work is performed. The Company owns a 33.75% interest in the Habanero field in Garden Banks Block 341. Habanero, which is operated by Shell, produced about 4,000 barrels of oil per day and 6 MMCF of gas per day net to the Company in 2005 and was adversely affected by hurricanes for approximately three months. Habanero production is expected to be lower in 2006 due to production decline on existing wells. The Company has a 37.5% interest in the Seventeen Hands field in Mississippi Canyon Block 299. This field, operated by Dominion, is projected to begin production in early 2006 following a delay in start-up caused by Hurricane Katrina. Daily net production should average 13 MMCF of gas per day for the second half of 2006, but the field is expected to begin decline in 2007. The other deepwater producing field is at Tahoe in Viosca Knoll Block 783, in which the Company has a 30% interest. Tahoe is operated by Shell and in 2005 produced about 8 MMCF of natural gas per day and 200 barrels of oil per day net to the Company. Tahoe production will be lower in 2006 than in 2005 due to two wells remaining off production after the 2005 hurricane. Hurricane Katrina and other storms caused temporary shut-in of wells and damaged facilities mostly owned by others, which ultimately reduced the Company’s 2005 net production in the U.S. by about 6,800 barrels of oil per day and 15 MMCF of natural gas per day. At year-end 2005, virtually all producing fields affected by Hurricane Katrina and other storms were back onstream. In 2004, Murphy announced a discovery at the Thunderhawk wildcat well in Mississippi Canyon Block 734 and in early 2005 announced a discovery at South Dachshund in Lloyd Ridge Blocks 1 and 2. Murphy has appraised the Thunderhawk discovery and expects to sanction a development plan during 2006. First production at Thunderhawk, where Murphy has a 37.5% interest, could occur in 2008. Natural gas production from the Lloyd Ridge discovery, now known as Mondo N.W., is expected in mid-2007 and Murphy has a 50% working interest in this property. Murphy holds an interest in 214 blocks in the deepwater Gulf of Mexico, and expects to drill two-to-four deepwater prospects per year over the next several years. Murphy sold most of its interests on the more shallow continental shelf in the Gulf of Mexico in mid-2005 for an after-tax profit of $104.5 million. Total production from these properties averaged about 4,400 barrels of net oil equivalent per day in 2005 prior to the sale. Total net proved reserves for these sold properties were 7.6 million barrels equivalent at the end of 2004. Onshore production, which is mostly natural gas, is primarily located on several leases in Vermilion Parish, Louisiana. Murphy’s net production in 2005 from onshore fields was 25 MMCF per day. The Company owns approximately a 1.4% working interest in the Northstar oil field in Alaska operated by BP. Total net oil production for this field was approximately 700 barrels per day in 2005. Murphy is in the early stages of an onshore U.S. exploration program searching for unconventional shale gas. The Company has drilled three unsuccessful wells through year-end 2005.

In Canada, the Company owns an interest in three legacy 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 Canada Sedimentary Basin (WCSB) in 2005. Murphy holds a 6.5% interest in Hibernia and a 12% interest in Terra Nova, with these being the first two fields on production in the Jeanne d’Arc Basin, offshore Newfoundland. Total net production in 2005 was 12,300 barrels of oil per day from Hibernia, which is operated by Hibernia Management and Development Company, while net production from Terra Nova, which is operated by PetroCanada, was 10,800 barrels of oil per day. Terra Nova production suffered from equipment reliability issues in 2005, and the current plan calls for a three-month shutdown for major equipment maintenance in the second half of 2006. Total 2006 net production at Hibernia and Terra Nova is anticipated to be approximately 11,500 and 6,500 barrels per day, 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 is nearing completion of the expansion of its facilities by adding a third coker that will allow for increased production beginning in the second quarter of 2006. Total net production in 2005 was 10,600 barrels of crude oil per day, but with the expansion net production is expected to be about 13,500 barrels per day in the second half of 2006. Although Syncrude produces a very high quality synthetic crude oil from bitumen, the U.S. Securities and Exchange Commission (SEC) does not allow the Company to include Syncrude’s reserves in its proved oil reserves, which are reported on page F-33. The SEC considers Syncrude to be a mining operation, and not a conventional oil operation. Production in 2005 in the WCSB averaged 12,300 barrels per day of mostly heavy oil and 10 MMCF of natural gas per day. An ongoing heavy oil development drilling program in the Seal area of Alberta is expected to increase WCSB oil production in 2006 by about 3,000 barrels per day. Natural gas production levels in 2006 should be similar to 2005.

Murphy produces oil and natural gas in the United Kingdom sector of the North Sea. The Company’s primary oil production in the U.K. is now derived from two areas, Schiehallion and Mungo/Monan. Murphy owns 5.88% of the BP operated Schiehallion field, which is located in an area known as the Atlantic Margin west of the Shetland Islands. Schiehallion produces oil into a Floating Production Storage and Offloading vessel (FPSO). The oil is transported via dedicated tanker to Sullom Voe terminal, where the oil is sold to third parties. Schiehallion produced approximately 3,700 net barrels of oil per day in 2005, with production being adversely affected by a fire and equipment reliability issues during the year. Schiehallion development will continue with further infield drilling planned in 2006 onwards. Murphy owns a 4.84% interest in the FPSO, which also handles production from a nearby field owned by others. Mungo/Monan is also operated by BP and is 12.65% owned by Murphy. The Mungo field produces through an unmanned platform, while Monan is produced through subsea facilities. Both the platform and subsea facilities are tied to a central processing facility that is linked to the Forties pipeline system. In 2005, the Mungo and Monan fields produced approximately 4,200 barrels of oil per day, net to Murphy’s interest. Total U.K. natural gas sales averaged about 9.4 MMCF per day in

2005 from production primarily at the Amethyst and Mungo/Monan fields. Oil production in the U.K. in 2006 should be similar to 2005, but natural gas sales are expected to be about 3 MMCF per day lower due to less sales volumes at the Amethyst field as 2005 volumes included about 2 MMCF per day of make-up gas associated with a prior year contract.

In Ecuador, Murphy owns a 20% working interest in Block 16, which is operated by Repsol YPF under a participation contract. The Company's net production was about 7,900 barrels of oil per day in 2005. Between June and December 2004, Murphy did not receive its equity share of oil sales from Block 16 due to a dispute with the operator involving the Company's new transportation and marketing arrangements. Murphy settled this matter with Repsol YPF in late 2005 and recouped about 663,000 barrels of oil of the 2004 shortfall. The Company is still owed about 853,000 barrels from other Block 16 working interest owners as of December 31, 2005. Murphy expects to resolve the matter with the other owners in 2006.

As of January 31, 2006, the Company has majority interests in nine separate production sharing contracts (PSCs) in Malaysia. The Company serves as the operator of all these areas, which cover approximately 12.3 million acres. Murphy has an 85% interest in two shallow water blocks, SK 309 and SK 311. The West Patricia and Congkak fields in Block SK 309 produced about 13,500 net barrels of oil per day in 2005. Net production in 2006 is anticipated to decline at these fields by 10%-15% due to a lower percentage of production allocable to the Company under the production sharing contract due to sustained high oil prices. The Company has also added discoveries in these shallow water blocks at Endau, Rompin, Belum, Golok and Serampang. The Company made a major discovery at the Kikeh field in deepwater Block K in 2002 and added another important discovery at Kakap in 2004. Further discoveries have been made in Block K at Senangin and Kerisi. In 2004, Murphy's Board of Directors and Malaysian authorities sanctioned the Kikeh field development plan, and in early 2005 engineering and construction contracts for major equipment were awarded. The Company has booked proved oil reserves of 38.9 million barrels related to the Kikeh field at year-end 2005. These proved reserves do not include any volumes attributable to pressure maintenance programs that the Company intends to utilize at the Kikeh field when production begins, which is currently projected to be in the second half of 2007. In early 2006, the Company relinquished a portion of Block K, offshore Sabah, and it 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 in the Kikeh and Kakap discoveries in Block K. The Company also added a new PSC in early 2006, now known as Block P, covering 1.05 million acres of the previously relinquished Block K area. Murphy holds a 60% interest in Block P. Murphy also owns 75% interests in Blocks PM 311 and PM 312, located offshore peninsular Malaysia. Murphy announced discoveries at Kenarong and Pertang in Block PM 311 in 2004, but was unsuccessful with additional exploration drilling in the PM blocks in 2005. The Company has an 80% interest in deepwater Block H offshore Sabah, and it expects to drill two wildcat wells on this block in 2006. 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 are held in suspension 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 on page 4.

The Company has 85% interests in Production Sharing Agreements (PSAs) covering two offshore blocks in the Republic of the 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 MPS. In 2005, the Company successfully appraised this discovery and tested an appraisal well at 8,000 barrels of oil per day from one zone. The Company drilled four unsuccessful exploratory wells on other parts of the MPS block in 2005. Further exploration drilling will occur in the area in 2006 prior to deciding upon a development plan for the Azurite Marine area.

Murphy's estimated net quantities of proved oil and gas reserves and proved developed oil and gas reserves at December 31, 2002, 2003, 2004 and 2005 by geographic area are reported on pages F-33 and F-34 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 six years ended December 31, 2005 are shown on page 6 of the 2005 Annual Report. In 2005, 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 17 of this Form 10-K report. For purposes of these computations, natural gas sales volumes are converted to equivalent barrels of crude oil using a ratio of six thousand cubic feet (MCF) of natural gas to one barrel of crude oil.

Supplemental disclosures relating to oil and gas producing activities are reported on pages F-32 through F-39 of this Form 10-K report.

At December 31, 2005, 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 working interest.

Area (Thousands of acres)	Developed Gross	Developed Net	Undeveloped Gross	Undeveloped Net	Total Gross	Total Net
United States – Onshore	5	3	329	155	334	158
– Gulf of Mexico	16	6	1,304	866	1,320	872
– Alaska	3	1	4	—	7	1
Total United States	24	10	1,637	1,021	1,661	1,031
Canada – Onshore	69	46	236	201	305	247
– Offshore	88	7	8,444	2,631	8,532	2,638
Total Canada	157	53	8,680	2,832	8,837	2,885
United Kingdom	33	4	69	20	102	24
Ecuador	7	1	524	105	531	106
Malaysia	2	2	14,431*	11,100*	14,433*	11,102*
Republic of Congo	—	—	1,773	1,507	1,773	1,507
Spain	—	—	36	6	36	6
Totals	223	70	27,150	16,591	27,373	16,661
Oil sands – Syncrude	96	5	159	8	255	13

* Includes 2,146 thousand gross acres and 1,717 thousand net acres in original Block K that were relinquished in January 2006 when new production sharing contracts for Blocks K and P were signed. The acreage also includes 2,935 thousand gross acres and 1,910 thousand net acres in Blocks L and M, which were awarded to the Company by Malaysia, but also have been claimed by the Sultanate of Brunei.

Excluding Block K acreage relinquished in early 2006 as discussed in the footnote to the preceding table, the only significant undeveloped acreage that expires in the next three years are approximately 5.8 million net acres in Malaysia and 1.5 million net acres offshore the east coast of Canada.

As used in the three tables that follow, "gross" wells are the total wells in which all or part of the working interest is owned by Murphy, and "net" wells are the total of the Company's fractional working interests in gross wells expressed as the equivalent number of wholly owned wells.

The following table shows the number of oil and gas wells producing or capable of producing at December 31, 2005.

Country	Oil Wells Gross	Oil Wells Net	Gas Wells Gross	Gas Wells Net
United States	32	7	15	7
Canada	423	309	60	43
United Kingdom	31	3	22	2
Malaysia	18	15	—	—
Ecuador	124	25	—	—
Totals	628	359	97	52

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
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**
2004												
Exploratory	1.3	2.0	4.6	1.4	—	0.1	6.0	5.8	—	—	11.9	9.3
Development	1.0	—	84.1	25.0	—	—	7.7	—	2.8	—	95.6	25.0
2003												
Exploratory	2.5	2.4	10.4	9.4	—	—	0.8	2.7	—	0.1	13.7	14.6
Development	2.4	—	108.2	3.9	0.2	0.3	4.1	—	2.4	—	117.3	4.2

The increase in the number of development dry hole wells in Canada in 2004 was caused by 23 nonproducing stratigraphic wells drilled in the Seal area for the purpose of placement of horizontal development wells for the field.

Murphy's drilling wells in progress at December 31, 2005 are shown below.

	Exploratory		Development		Total	
Country	Gross	Net	Gross	Net	Gross	Net
Canada	—	—	8.0	3.4	8.0	3.4
United Kingdom	—	—	2.0	0.1	2.0	0.1
Malaysia	1.0	0.8	—	—	1.0	0.8
Ecuador	—	—	2.0	0.4	2.0	0.4
Totals	1.0	0.8	12.0	3.9	13.0	4.7

Refining and Marketing

The Company's refining and marketing businesses are located in North America and the United Kingdom, and primarily consist of operations that refine crude oil and other feedstocks into petroleum products such as gasoline and distillates, buy and sell crude oil and refined products, and transport and market petroleum products.

Murphy Oil USA, Inc. (MOUSA), a wholly owned subsidiary of Murphy Oil Corporation, owns and operates two refineries in the United States. The Meraux, Louisiana refinery is located on fee land and on two leases that expire in 2010 and 2021, at which times the Company has options to purchase the leased acreage at fixed prices. The refinery at Superior, Wisconsin is located on fee land. Murco Petroleum Limited (Murco), a wholly owned U.K. subsidiary serviced by Murphy Eastern Oil Company, has an effective 30% interest in a refinery at Milford Haven, Wales that can process 108,000 barrels of crude oil per day.

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Refinery capacities at December 31, 2005 are shown in the following table.

	Meraux, Louisiana[2]	Superior, Wisconsin	Milford Haven, Wales (Murco's 30%)	Total
Crude capacity – b/sd[1]	125,000	35,000	32,400	192,400
Process capacity – b/sd[1]				
Vacuum distillation	50,000	20,500	16,500	87,000
Catalytic cracking – fresh feed	37,000	11,000	9,960	57,960
Naphtha hydrotreating	35,000	9,000	5,490	49,490
Catalytic reforming	32,000	8,000	5,490	45,490
Gasoline hydrotreating	—	7,500	—	7,500
Distillate hydrotreating	52,000	7,800	20,250	80,050
Hydrocracking	32,000	—	—	32,000
Gas oil hydrotreating	12,000	—	—	12,000
Solvent deasphalting	18,000	—	—	18,000
Isomerization	—	2,000	3,400	5,400
Production capacity – b/sd[1]				
Alkylation	8,500	1,500	1,680	11,680
Asphalt	—	7,500	—	7,500
Crude oil and product storage capacity – barrels	4,336,000	3,085,000	2,638,000	10,059,000

1 Barrels per stream day.

2 The Meraux refinery is temporarily shut down for repairs following Hurricane Katrina. See further details in the following paragraph.

In late August 2005, the Meraux, Louisiana refinery was severely damaged by flooding and high winds caused by Hurricane Katrina. The plant has been down for repairs since the hurricane and restart of the plant is expected early in the second quarter of 2006. The costs to repair the Meraux refinery are expected to be mostly covered by insurance. Oil Insurance Limited (O.I.L.), the Company's primary property insurance coverage, has informed insureds that recoveries for Hurricane Katrina damages will likely be no more than 50% of claimants' eligible losses. Murphy has other commercial insurance coverage for repair costs not covered by O.I.L., but the coverage limits recoveries from flood damage to $50 million. Costs to repair the refinery have been estimated at $200 million. If the insurance recoveries and repair costs are as described, the Company has estimated that uninsured repair costs could range up to $50 million in the first half of 2006.

Murphy has expanded the Meraux refinery allowing the refinery to meet low-sulfur gasoline specifications which become effective in 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. The Meraux plant had no solvent deasphalting processing capability during 2004 and early 2005 because of the fire in June 2003 that destroyed the Residual Oil Supercritical Extractor (ROSE) unit. The ROSE unit has been rebuilt, primarily using proceeds of property insurance, and was restarted in early 2005. While the ROSE unit was being rebuilt, the refinery produced a larger volume of heavy fuel oil. During 2004 the Company also completed an FCC gasoline hydrotreater unit at its Superior, Wisconsin refinery, that allows the refinery to meet low-sulfur gasoline specifications.

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 areas of Wal-Mart Supercenters in 21 states and use the brand name Murphy USA®. Branded wholesale customers use the brand name SPUR®. Refined products are supplied from 11 terminals that are wholly owned and operated by MOUSA, one terminal that is jointly owned and operated by others, and numerous terminals owned by others. Of the wholly owned terminals, three are supplied by marine transportation, three are supplied by truck, three are supplied by pipeline and two are adjacent to MOUSA's refineries. MOUSA receives products at the terminals owned by others either in exchange for deliveries from the Company's terminals or by outright purchase. The Company sold all but one of its jointly owned terminals in early 2004. At December 31, 2005, the Company marketed products through 864 Murphy USA stations and 329 branded wholesale SPUR stations. MOUSA plans to add about 130 new Murphy USA stations at Wal-Mart Supercenters in the southern and midwestern United States in 2006. The Company's Canadian subsidiary operates eight Murphy Canada™ stations at Wal-Mart sites in Canada.

Murphy has master agreements that allow the Company to rent space in the parking lots of Wal-Mart Supercenters in 21 states and in Canada for the purpose of building retail gasoline stations. The master agreements contain general terms applicable to all sites in the United States and Canada. As each individual station is constructed, an addendum to the master agreement is executed, which contains the terms specific to that location. 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 amounted to 44.6% of total Company revenues in 2005, 38.6% in 2004 and 35.8% in 2003. As the Company continues to expand the number of gasoline stations at Wal-Mart Supercenters, total revenue generated by this business is expected to grow.

At the end of 2005, Murco distributed refined products in the United Kingdom from the 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 412 branded stations primarily under the brand name MURCO. During 2005, Murco purchased 68 existing retail fueling stations.

Murphy owns a 20% interest in a 120-mile refined products pipeline, with a capacity of 165,000 barrels per day, that transports products from the Meraux refinery to two common carrier pipelines serving the southeastern United States. The Company also owns a 3.2% interest in the Louisiana Offshore Oil Port LLC (LOOP), which provides deepwater unloading accommodations off the Louisiana coast for oil tankers and onshore facilities for storage of crude oil. A crude oil pipeline with a diameter of 24 inches connects LOOP storage at Clovelly, Louisiana to the Meraux refinery. Murphy owns 29.4% of the first 22 miles of this pipeline from Clovelly to Alliance, Louisiana and 100% of the remaining 24 miles from Alliance to Meraux. The 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 2005, 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 1.8%.

A statistical summary of key operating and financial indicators for each of the six years ended December 31, 2005 are reported on page 7 of the 2005 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 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, develop and produce hydrocarbons in promising areas. In addition, it must drill, develop and produce 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.

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 2005 was favorably affected by higher oil and natural gas prices; if these prices decline significantly in 2006 or future years, the Company's results of operations would be negatively impacted. 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 drills numerous wildcat wells each year which subjects its operating results to significant exposure to dry holes expense, which have adverse effects on, and create volatility for, the Company's net income. In 2005, these wildcat wells were primarily drilled offshore Malaysia, the Republic of Congo and in the U.S. Gulf of Mexico.

Capital Financing

Murphy usually must spend and risk a significant amount of capital to find and develop reserves prior to the time 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, and therefore, these 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 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 often has little or no influence on the sales prices 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 located at Wal-Mart Supercenters. 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 oil, natural gas and refined product prices such as those experienced in 2005 because an increase in exploration and production activities due to higher 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.

Most of the Company's major producing properties are operated by others. In addition, Murphy derives a significant portion of its U.S. revenue at Company-owned and operated gasoline stations located on properties leased from Wal-Mart. Therefore, Murphy does not fully control all activities at certain of its significant, revenue generating properties.

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.

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, 2005, approximately 35% of proved oil reserves, as defined by the U.S. Securities and Exchange Commission, were located in countries other than the U.S., Canada and 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 and regulations concerning: currency fluctuations, protection and remediation of the environment (See the caption "Environmental" beginning on page 22 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 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, and intentional 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.

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, 2005, 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. At year-end 2005, the Company was in the process of repairing the Meraux refinery. The Company does not expect to fully recover repair costs incurred at Meraux in 2006 under its insurance policies. See Note O in the consolidated financial statements for further discussion.

Litigation

The Company is involved in lawsuits seeking cash settlements for alleged personal injuries, property damages and other business-related matters. These matters are addressed in more detail in Item 3 on page 10 of this Form 10-K report.

Retirement Plans

A number of actuarial assumptions significantly impact funding requirements for the Company's retirement plans. Such assumptions include return on assets, mortality, long-term interest rates, etc. If the actual results for the plans vary significantly from the actuarial assumptions used, Murphy could be required to make large funding payments to one or more of its retirement plans in the future.

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, 2005.

Item 2. PROPERTIES

Descriptions of the Company's oil and natural gas and refining and marketing properties are included in Item 1 of this Form 10-K report beginning on page 1. Information required by the Securities Exchange Act Industry Guide No. 2 can be found in the Supplemental Oil and Gas Information section of this Annual Report on Form 10-K on pages F-32 to F-39 and in Note D—Property, Plant and Equipment on page F-12.

Executive Officers of the Registrant

The age at January 1, 2006, 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 51; President and Chief Executive Officer since October 1994 and Director and Member of the Executive Committee since 1993.

Steven A. Cossé – Age 58; 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.

W. Michael Hulse – Age 52; Executive Vice President – Worldwide Downstream Operations effective April 2003. Mr. Hulse has been President of Murphy Oil USA, Inc. from November 2001 to present. He served as President of Murphy Eastern Oil Company from April 1996 to November 2001.

Bill H. Stobaugh – Age 54; Senior Vice President since February 2005. Mr. Stobaugh joined the Company as Vice President in 1995.

Kevin G. Fitzgerald – Age 50; Treasurer since July 2001. Mr. Fitzgerald was Director of Investor Relations from 1996 to June 2001.

John W. Eckart – Age 47; Controller since March 2000.

Walter K. Compton – Age 43; 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 flooding damage to a crude oil storage tank following Hurricane Katrina. Since then additional class action lawsuits have been filed in the same court against Murphy Oil USA, Inc. and/or Murphy Oil Corporation also seeking unspecified damages related to the crude oil release. The suits have been consolidated into a single action in the U.S. District Court for the Eastern District of Louisiana, which held a class certification hearing on January 12-13, 2006. The Court certified the class on January 30, 2006. The Company believes that insurance coverage exists for this release and it does not expect to incur significant costs associated with the class action lawsuits. Accordingly, the Company believes that the ultimate resolution of these class action lawsuits will not 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. 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.

In December 2000, two of the Company's Canadian subsidiaries, Murphy Oil Company Ltd. (MOCL) and Murphy Canada Exploration Company (MCEC) as plaintiffs filed an action in the Court of Queen's Bench of Alberta seeking a constructive trust over oil and gas leasehold rights to Crown lands in British Columbia. The suit alleges that the defendants, The Predator Corporation Ltd. and Predator Energies Partnership (collectively Predator) and Ricks Nova Scotia Co. (Ricks), acquired the lands after first inappropriately obtaining confidential and proprietary data belonging to the Company and its partner. In January 2001, Ricks, representing an undivided 75% interest in the lands in question, settled its portion of the litigation by conveying its interest to the Company and its partner at cost. In 2001, Predator, representing the remaining undivided 25% of the lands in question, filed a counterclaim against MOCL and MCEC and MOCL's President individually seeking compensatory damages of C$3.61 billion. In September 2004 the court summarily dismissed all claims against MOCL's president and all but C$356 million of the counterclaim against the Company. On February 28, 2006, the Court of Appeals ruled in favor of the Company and affirmed the dismissal order. The Company believes that the counterclaim is without merit, that the amount of damages sought is frivolous and the likelihood of a material loss to the Company is remote. It is anticipated that a trial concerning the 25% disputed interest and any remaining issues will commence in 2006. While no assurance can be given about the outcome, the Company does not believe that the ultimate resolution of this suit will have a material adverse effect on its net income, financial condition or liquidity in a future period. In the unlikely event that Predator were to prevail in its counterclaim for an amount approaching the damages sought, Murphy would incur a material expense in its consolidated statement of income, and would have a material effect on its financial condition and liquidity.

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 2005.

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 2,847 stockholders of record as of December 31, 2005. Information as to high and low market prices per share and dividends per share by quarter for 2005 and 2004 are reported on page F-40 of this Form 10-K report.

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Item 6. SELECTED FINANCIAL DATA

(Thousands of dollars except per share data)	2005	2004	2003	2002	2001
Results of Operations for the Year					
Sales and other operating revenues	$ **11,680,079**	8,299,147	5,094,518	3,779,381	3,579,143
Net cash provided by continuing operations	**1,216,713**	1,035,057	501,127	372,205	491,326
Income from continuing operations	**837,903**	496,395	278,410	87,279	296,563
Net income	**846,452**	701,315	294,197	111,508	330,903
Per Common share – diluted*					
Income from continuing operations	**4.46**	2.65	1.50	.47	1.63
Net income	**4.51**	3.75	1.59	.61	1.81
Cash dividends per Common share*	**.45**	.425	.40	.3875	.375
Percentage return on					
Average stockholders' equity	**28.3**	31.3	16.4	7.3	23.5
Average borrowed and invested capital	**23.6**	21.8	11.0	5.8	17.7
Average total assets	**14.5**	13.5	6.7	3.9	10.2
Capital Expenditures for the Year					
Continuing operations					
Exploration and production	$ **1,091,954**	839,182	689,632	538,994	500,726
Refining and marketing	**202,401**	134,706	215,362	234,714	175,186
Corporate and other	**35,476**	1,505	1,120	1,136	5,806
	1,329,831	975,393	906,114	774,844	681,718
Discontinued operations	**—**	9,065	73,050	93,256	182,722
	$ **1,329,831**	984,458	979,164	868,100	864,440
Financial Condition at December 31					
Current ratio	**1.43**	1.35	1.28	1.19	1.07
Working capital	$ **551,938**	424,372	228,529	136,268	38,604
Net property, plant and equipment	**4,374,229**	3,685,594	3,530,800	2,886,599	2,525,807
Total assets	**6,368,511**	5,458,243	4,712,647	3,885,775	3,259,099
Long-term debt	**609,574**	613,355	1,090,307	862,808	520,785
Stockholders' equity	**3,460,990**	2,649,156	1,950,883	1,593,553	1,498,163
Per share*	**18.61**	14.39	10.62	8.69	8.26
Long-term debt – percent of capital employed	**15.0**	18.8	35.9	35.1	25.8

* Per share amounts for 2001 to 2004 have been adjusted to reflect the two-for-one stock split effective June 3, 2005.

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 North America and the United Kingdom. A more detailed description of the Company's significant assets can be found in Item 1 of this Form 10-K report.

Murphy generates revenue primarily by selling its oil and natural gas production and its 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 North America 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 downstream operations are dependent upon achieving adequate refining and marketing 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 and North American natural gas prices were stronger in 2005 than in 2004. The average price for a barrel of West Texas Intermediate crude oil in 2005 was $56.70, an increase of 37% compared to 2004. The NYMEX natural gas price in 2005 averaged $8.97 per million British Thermal Units (MMBTU), up 45% over 2004. These price improvements, particularly for crude oil, were a significant factor leading to higher profits in the Company's exploration and production business in 2005 compared to 2004. If the prices for crude oil and natural gas decline significantly in 2006 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 2005 of $846.5 million, $4.51 per diluted share, compared to net income in 2004 of $701.3 million, $3.75 per diluted share. In 2003 the Company's net income was $294.2 million, $1.59 per diluted share. The higher net income in 2005 compared to 2004 was caused by a combination of better earnings in the Company's exploration and production and refining and marketing operations and lower net costs for corporate functions. The larger net income in 2004 compared to 2003 was also caused by better earnings in the exploration and production and refining and marketing businesses, but was unfavorably affected by higher net costs of corporate activities. Further explanations of each of these variances are found in the following sections.

Income from continuing operations was $837.9 million, $4.46 per diluted share, in 2005, $496.4 million, $2.65 per diluted share, in 2004, and $278.4 million, $1.50 per diluted share, in 2003.

Each of the three years ended December 31, 2005 included income from discontinued operations. 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. In accordance with Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, the gain on sale of these assets and operating results for the fields prior to their sale have been presented, net of income tax expense, as Discontinued Operations in the consolidated statements of income for the three-year period ended December 31, 2005. Income from discontinued operations was $8.6 million, $.05 per diluted share, in 2005, $204.9 million, $1.10 per diluted share, in 2004, and $22.8 million, $.12 per diluted share, in 2003. 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.

On January 1, 2003, the Company adopted Statement of Financial Accounting Standards (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. Upon adoption of SFAS No. 143, the Company recorded an expense of $7 million, net of $1.4 million in income taxes, as the cumulative effect of a change in accounting principle. Further explanation of this accounting change is included in Note G to the consolidated financial statements. Income before the cumulative effect of a change in accounting principle was $301.2 million, $1.62 per diluted share, in 2003.

2005 vs. 2004 – Net income in 2005 was $846.5 million, $4.51 per share, compared to $701.3 million, $3.75 per share, in 2004. Income from continuing operations amounted to $837.9 million, $4.46 per share, in 2005 compared to $496.4 million, $2.65 per share, in 2004. The $341.5 million improvement in income from continuing operations in 2005 was caused by more favorable results in each of the Company's exploration and production (E&P), refining and marketing (R&M) and corporate activities. Higher sales prices in 2005 for the Company's oil and natural gas production was the primary driver for improved earnings of $235.8 million in the E&P business. The other favorable factors in this business in 2005 were higher oil sales volumes and a larger gain on sale of oil and natural gas properties. The Company's E&P earnings were unfavorably affected in 2005 by several factors, including higher insurance costs mostly caused by Hurricanes Katrina and Rita, lower sales volumes for natural gas due to both the sale of properties in the Gulf of Mexico and downtime caused by the hurricanes, higher exploration expenses, lower income tax benefits and rising costs of supplies and services. R&M earnings were $125.3 million in 2005, up $43.4 million compared to 2004 due to stronger realized margins for petroleum products sold in the U.S. and U.K. The Company expanded its retail fuel operations in each of these countries in 2005 by adding 112 retail fuel outlets at Wal-Mart Supercenters in the U.S. and by purchasing 68 existing retail fuel stations in the U.K. The net costs of corporate activities were $62.3 million lower in 2005 than in 2004, with the favorable variance in 2005 mostly due to a combination of higher tax benefits associated with refund and settlement of prior year U.S. taxes, lower Canadian withholding taxes on dividends to Murphy Oil Corporation from its Canadian subsidiary, favorable effects from foreign currency exchange, and less net interest costs due to lower average borrowings and the capitalization of more interest costs on development projects in the E&P business. These were partially offset by higher selling and general expenses in 2005, with the majority of this increase caused by larger employee compensation and benefit costs.

The Company sold most of its conventional oil and natural gas assets in western Canada in 2004, and net income in 2005 and 2004 included income from these discontinued operations of $8.6 million and $204.9 million, respectively, which represented per share earnings of $.05 in 2005 and $1.10 in 2004. Discontinued operations income in 2005 arose from a favorable adjustment of income taxes associated with the gain on sale in 2004. In 2004, cash proceeds of $583 million from the sale led to an after-tax gain of $171.1 million, which is included in the 2004 amount above.

Sales and other operating revenues in 2005 were $3.4 billion higher than in 2004 primarily due to higher sales prices for oil, natural gas and refined petroleum products, higher sales volumes of crude oil and refined petroleum products, and higher merchandise sales revenue at retail gasoline stations. Sales were unfavorably affected in 2005 by lower volumes of natural gas sold. The gain on sale of assets was $105.5 million higher in 2005, mostly due to a pretax gain of $165 million on the sale of oil and gas properties on the Gulf of Mexico continental shelf in 2005, partially offset by pretax profits in 2004 on sale of various properties. Interest and other income was favorable by $30.8 million in 2005 compared to 2004 mostly due to unfavorable foreign currency exchange losses in 2004 that did not repeat in 2005 and higher interest income on a U.S. income tax refund in 2005. Crude oil and product purchases expense increased by $2.6 billion in 2005 due to higher prices for crude oil and other purchased refinery feedstocks and higher prices for refined petroleum products purchased for sale at retail gasoline stations. Operating expenses increased $112.6 million in 2005 due mostly to costs associated with more crude oil production and more retail service stations in operations in the U.S. and U.K. Exploration expenses in the E&P business were $68.2 million higher in 2005 than in 2004 mostly due to more dry holes in Malaysia and the Republic of Congo, plus more spending on 3-D seismic acquisition and processing in Malaysia in 2005. Costs associated with hurricanes in 2005 of $66.8 million related to additional insurance, repairs and other costs that arose due to hurricanes in the Gulf of Mexico during the year. These storms, which damaged and led to temporary shut-down of certain offshore U.S. oil and gas facilities and the Meraux, Louisiana refinery, led to uninsured repair costs of about $15.5 million in 2005 and caused insurance costs for the year to rise by approximately $23.0 million. Also included in this cost category is $19.5 million of ongoing Meraux refinery salaries, benefits, depreciation and maintenance costs while the refinery is shut-down for repairs, and also donations and additional employee compensation totaling $8.8 million. In accordance with the Company's accounting policies, the increase in certain insurance costs related to the storm losses incurred by insurance companies has been allocated to all segments of the Company's business as all assets are covered by this property insurance. Costs associated with hurricanes were $3.4 million in 2004, and were previously included in operating expenses in the 2004 consolidated statement of income in the 2004 Form 10-K. Selling and general expenses were $26.6 million more in 2005 mostly due to higher employee compensation and benefit costs. Depreciation, depletion and amortization expense was $75.4 million higher in 2005 due to more volumes of crude oil sold and more fueling stations operating in the U.S. and U.K. The Company is experiencing higher drilling and other capital costs, which appear to be caused by added demand for such services due to the higher level of oil and natural gas sales prices. Accretion of asset retirement obligations was down $.3 million in 2005 due to sales of oil and natural gas properties on the continental shelf of the Gulf of Mexico in 2005. Interest expense was down by $8.9 million in 2005 compared to 2004 due to lower average outstanding debt in 2005. The portion of interest expense capitalized to development projects rose by $16.4 million in 2005 primarily due to higher interest allocated to the Kikeh development in Malaysia and the Syncrude expansion in western Canada. Income tax expense was up $225.6 million in 2005 mostly due to higher pretax earnings. The effective income tax rate as a percentage of pretax income in 2005 of 38.9% was unfavorably impacted by no tax benefits recognized on exploration expenses incurred in the Republic of Congo and Blocks PM 311/312 and H in Malaysia, but was favorably affected by income tax benefits of $21.8 million mostly related to refund and settlement of prior year U.S. income tax matters.

2004 vs. 2003 – Net income in 2004 was $701.3 million, $3.75 per share, compared to $294.2 million, $1.59 per share, in 2003. Both periods included income from discontinued operations associated with conventional oil and natural gas properties in western Canada that were sold in the second quarter 2004. Income from discontinued operations amounted to $204.9 million in 2004 and $22.8 million in 2003, $1.10 and $.12 per share, respectively. The 2004 amount included a $171.1 million gain net of taxes associated with the sale. The Company received proceeds of $583 million from the sale. The 2003 period included an after-tax expense of $7 million, $.03 per share, for the cumulative effect of a change in accounting principle associated with adoption of SFAS No. 143, Accounting for Asset Retirement Obligations. Income from continuing operations totaled $496.4 million, $2.65 per share, in 2004 compared to $278.4 million, $1.50 per share, in 2003. The $218 million improvement in income from continuing operations in 2004 was due to a combination of higher earnings from the Company's exploration and production and refining and marketing operating businesses. Higher net costs of corporate activities partially offset the better results from these operating businesses. E&P operating results improved $208.9 million mostly due to higher oil and natural gas sales prices, higher oil sales volumes, and a $31.9 million deferred income tax benefit in Malaysia due to the expectation that temporary differences associated with exploration and other costs incurred to-date in Block K will be utilized to reduce future taxable income. The E&P results were unfavorably affected in 2004 by higher exploration expenses and lower natural gas sales volumes compared to 2003. R&M operating results improved by $93.1 million in 2004 compared to 2003 primarily due to much stronger realized margins on refined petroleum products sold by the U.S. and U.K. businesses. The net costs of corporate activities were $84 million higher in 2004 because of a 5% withholding tax on a $550 million dividend to Murphy Oil Corporation from the Company's Canadian subsidiary, unfavorable foreign exchange variances in 2004, a $20.1 million tax benefit in 2003 related to settlement of U.S. tax matters, lower capitalized interest costs in 2004 due to the completion of significant E&P development projects, and higher administrative expenses in 2004 related mostly to Sarbanes-Oxley compliance and retirement plans. The Canadian withholding tax in 2004 amounted to $27.5 million of costs. Foreign exchange losses were $18.6 million after taxes in 2004 compared to an after-tax benefit of $5.4 million in 2003. These 2004 losses were primarily associated with U.S. dollar balances of cash and other net assets held by the Company's Canadian and U.K. subsidiaries, which generally use local currency as their functional currency for accounting purposes.

Sales and other operating revenues in 2004 increased $3.2 billion compared to 2003 mostly due to higher prices for oil, natural gas and refined petroleum products sold, higher sales volumes of crude oil and refined petroleum products, and higher merchandise sales revenue at retail gasoline stations. Gain on sale of assets increased by $8.1 million in 2004 due to a higher profit on sales of E&P properties in the year compared to 2003. Interest and other income was unfavorable by $17.5 million in 2004 versus 2003 mostly because of pretax foreign exchange losses of $26.6 million in 2004 compared to gains of $5.6 million in 2003; the foreign exchange effects were partially offset by higher interest income earned on invested cash balances during 2004. Crude oil and product purchases expense increased by $2.5 billion in 2004 due to the higher prices for crude oil purchased as refinery feedstocks and refined petroleum products purchased for sale at retail gasoline stations, and higher purchased volumes of crude oil, refined petroleum products and merchandise for resale compared to 2003. Operating expenses increased $153.9 million in 2004 with the change due to higher lifting costs caused by crude oil production growth and higher unit rates, higher refining and gasoline station expenses, and higher insurance and repair costs caused mostly by storms in the Gulf of Mexico. Exploration expenses rose by $51.6 million in 2004 mostly due to higher dry hole costs offshore eastern Canada and in Malaysia. Selling and general expenses were $12.8 million higher in the current year and increased due to consulting fees associated with Sarbanes-Oxley compliance, plus increases for salaries, retirement and other benefits, and incentive compensation. Depreciation, depletion and amortization rose by $62.6 million mostly due to higher production of crude oil and higher depreciation of refining and marketing assets. Property impairments of $8.3 million in 2003 related to write-down of a refined products terminal closed by the company, write-off of certain property costs that were rendered obsolete at the Meraux refinery and the write-down of a natural gas field in the Gulf of Mexico due to downward revisions in reserves caused by poor well performance. Accretion of asset retirement obligations increased by $.3 million, mostly due to drilling wells and facilities added during 2004. Interest expense was $1.5 million less than in 2003 mostly due to lower average debt outstanding during 2004. Capitalized interest credited to income and included in capital expenditures decreased by $15.1 million due to completion of the Medusa development project in the Gulf of Mexico and the expansion project at the Meraux refinery. Income tax expense was $212.7 million higher in 2004 than 2003 mostly due to higher pretax income, but also because of a $20.1 million benefit in 2003 from settlement of prior year U.S. tax audits. Income tax expense in 2004 included a $31.9 million benefit in Malaysia related to expected future tax deductions for life-to-date exploration and other expenses in Block K, but this was mostly offset by a $27.5 million charge for a 5% withholding tax on a dividend from a Canadian subsidiary.

In the following table, the Company's results of operations for the three years ended December 31, 2005 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)	**2005**	**2004**	**2003**
Exploration and production			
United States	**$385.5**	159.5	23.3
Canada	**308.2**	232.2	166.2
United Kingdom	**79.9**	87.1	95.3
Ecuador	**38.1**	6.6	16.7
Malaysia	**(4.7)**	38.3	10.7
Other	**(58.9)**	(11.4)	(8.8)
	748.1	512.3	303.4
Refining and marketing			
North America	**85.5**	53.4	(21.2)
United Kingdom	**39.8**	28.5	10.0
	125.3	81.9	(11.2)
Corporate and other	**(35.5)**	(97.8)	(13.8)
Income from continuing operations	**837.9**	496.4	278.4
Income from discontinued operations	**8.6**	204.9	22.8
Income before cumulative effect of change in accounting principle	**846.5**	701.3	301.2
Cumulative effect of change in accounting principle	**—**	—	(7.0)
Net income	**$846.5**	701.3	294.2

Exploration and Production – Earnings from exploration and production operations were $748.1 million in 2005, $512.3 million in 2004 and $303.4 million in 2003. The higher earnings in 2005 versus 2004 were due to a 26% higher average realized oil sales price, a 33% higher average realized sales price for natural gas in North America, a 16% increase in worldwide oil sales volumes from continuing operations, and higher gains on sale of mature properties. The favorable variances were somewhat offset by an 18% lower volume of natural gas sales from continuing operations, higher exploration expenses, higher production and depreciation expenses, higher insurance and repair costs after Hurricanes Katrina and Rita and lower income tax benefits in Malaysia. The 2005 period included a $104.5 million after-tax gain on sale of most oil and gas properties on the continental shelf of the Gulf of Mexico. Higher oil production in 2005 was primarily caused by a full year of production at the Front Runner field in the deepwater Gulf of Mexico and higher heavy oil production from the Seal area in western Canada in response to an ongoing development drilling program. Natural gas sales volume declined in 2005 versus 2004 mostly due to the sale of properties on the Gulf of Mexico continental shelf and more downtime in the Gulf of Mexico caused by hurricane shut-in and repairs.

The increase in 2004 earnings compared to 2003 was due to a 37% higher average realized oil sales price, a 24% higher realized sales price for North American natural gas, a 17% higher sales volume of crude oil, condensate and natural gas liquids, a $31.9 million deferred income tax benefit on inception-to-date Block K exploration and other expenses, and lower impairment charges. These favorable variances more than offset lower volumes of natural gas production, higher production and depreciation expenses associated with increased oil production, higher exploration expenses caused by more dry hole costs offshore eastern Canada and in Malaysia, higher insurance costs related to a retrospective premium adjustment on property insurance coverage and higher costs to repair damages to facilities caused by Hurricane Ivan. Higher oil production in 2004 was attributable to a full year of production in 2004 at Medusa and Habanero in the deepwater Gulf of Mexico and at West Patricia in Block SK 309 in Malaysia. The decline in natural gas production in 2004 was due to field decline at Amethyst in the U.K. North Sea and downtime in the Gulf of Mexico for repairs after Hurricane Ivan.

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-36 and F-37 of this Form 10-K report. Average daily production and sales rates and weighted average sales prices are shown on page 6 of the 2005 Annual Report.

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

(Millions of dollars)	2005	2004	2003
United States			
Oil and gas liquids	**$ 448.8**	248.4	39.2
Natural gas	**216.6**	207.6	158.3
Canada			
Conventional oil and gas liquids	**519.7**	403.3	314.8
Natural gas	**29.7**	28.7	34.9
Synthetic oil	**224.7**	174.2	95.7
United Kingdom			
Oil and gas liquids	**159.8**	146.8	158.6
Natural gas	**19.9**	11.4	12.2
Malaysia – crude oil	**232.9**	167.2	77.7
Ecuador – crude oil	**116.6**	30.8	41.9
Total oil and gas revenues	**$1,968.7**	1,418.4	933.3

The Company's crude oil, condensate and natural gas liquids production from continuing operations averaged 101,349 barrels per day in 2005, 93,634 barrels per day in 2004 and 76,620 barrels in 2003. Oil production in 2005 was a new annual record for Murphy Oil. The 8% increase in worldwide oil production in 2005 was primarily due to higher volumes in the United States, Malaysia and Canada. U.S. oil production was 34% higher in 2005 and totaled 25,897 barrels per day, with the increase mostly due to a full year of production from the Front Runner field in the deepwater Gulf of Mexico at Green Canyon Blocks 338/339. The first well at Front Runner came on stream in December 2004 and additional wells were completed and started up during 2005 and into early 2006. Production in the U.S. was hampered during 2005 by the effects of hurricanes as minor damages to the Company's Medusa and Habanero facilities and damages to product evacuation lines and other facilities downstream caused shut-in of production for up to three months. Production offshore Sarawak, Malaysia at the West Patricia and Congkak fields increased 14% in 2005 to 13,503 barrels per day. The increase was mostly due to a 31% increase in gross production from these fields, but this was partially offset by a lower revenue sharing percentage for the Company under the terms of the production sharing contract. The West Patricia field generated approximately 94% of Malaysian production in 2005. Heavy oil production in Canada essentially doubled to 11,806 barrels per day in 2005 due to an ongoing development drilling program in the Seal area and a full year of production from wells acquired in late 2004 in this area. Production at the Hibernia field off the east coast of Canada was down 4% to 12,278 barrels per day and production at the Terra Nova field in this area was off 14% in 2005 and amounted to 10,846 barrels per day. Lower production at Terra Nova was primarily caused by more downtime for equipment maintenance and repairs and a higher royalty rate. Production of synthetic oil at Syncrude netted the Company 10,593 barrels per day in 2005, down 10% from 2004 due to more downtime for equipment repairs. Total oil production offshore the United Kingdom was 7,992 barrels per day in 2005, down 27%. About 1,200 barrels per day of this decline was attributable to the sale of the “T” Block field in 2004. The majority of the remaining decline was at the Schiehallion field where a fire and other operational issues reduced average net production volumes by about 1,600 barrels per day. Production in Ecuador was 7,871 barrels per day in 2005, up 2% from 2004. Oil sales volumes in Ecuador in 2005 were significantly higher than production volumes due to receiving 663,000 barrels of oil for sale in settlement of a 2004 dispute with the operator of Block 16. Murphy expects to make up the remainder of the sales volume shortfall of about 853,000 barrels owed to the Company by other Block 16 owners in 2006.

Comparing 2004 to 2003, worldwide oil production from continuing operations increased 22%, primarily attributable to production growth in the U.S. and Malaysia. Oil production in Canada and the U.K. declined in 2004 compared to 2003. U.S. oil production increased more than 300% to 19,314 barrels per day due to a full year of production in 2004 from the Medusa and Habanero fields. Both these deepwater Gulf of Mexico fields came on stream in November 2003. Heavy oil production in Canada increased 24% to 5,838 barrels per day due to a heavy oil drilling program in the Seal area during 2004, plus additional producing wells acquired in this area during the fourth quarter of 2004. Production at the Hibernia field off the east coast of Canada was essentially flat with 2003 at 12,736 barrels per day, but the Terra Nova field saw production decrease 19% to 12,671 barrels per day, with the decline mostly due to mechanical problems and an oil spill that occurred during the year. Net synthetic oil production from the Syncrude project was 11,794 barrels per day, a 13% increase from 2003. The increase at Syncrude was in line with higher gross production, which was caused by better operational efficiency and less downtime in 2004 compared to 2003. Oil production in the U.K. was lower by 25% and averaged 11,011 barrels per day. The Company sold its interest in the “T” Block field in 2004 and the Ninian and Columba fields in 2003. Also, production from the Schiehallion and Mungo/Monan fields was down in 2004 due to normal decline. Production in Ecuador rose almost 50% in 2004 due to a full year of operation for the new heavy oil pipeline. In prior years, production restrictions were in effect due to limitations caused by inadequate pipeline capacity between the primary oil producing region in the country’s interior to the sales point on the Pacific coast. In spite of the higher Ecuadorian production in 2004, total sales volumes in this country in 2004 were lower than 2003 because no sales occurred from Block 16 for the Company’s account during the second half of the year due to a dispute with the operator of the field over Murphy’s new transportation and marketing arrangements. The Company settled this issue with the operator in 2005 as described in the preceding paragraph. Malaysian oil production rose 63% in 2004 and averaged 11,885 barrels per day, caused by a full year of production in the current year from the West Patricia field in Block SK 309 versus a partial year in 2003.

Worldwide sales of natural gas from continuing operations were 90.2 million cubic feet per day in 2005, 109.5 million in 2004 and 111.8 million in 2003. Sales of natural gas in the United States were 70.5 million cubic feet per day in 2005, 88.6 million in 2004 and 82.3 million in 2003. Sales volume declined by 21% in the U.S. in 2005 due to the sale of most properties on the continental shelf of the Gulf of Mexico in mid-2005, which caused a decrease of 14 million cubic feet per day, and the effects of Hurricane Katrina and other Gulf storms that caused shut-ins that reduced production by an average of about 15 million cubic feet per day for the year. These were partially offset by higher volumes due to ramp up of production at the Front Runner field throughout 2005. Sales in the U.S. were higher in 2004 than 2003 as more volumes produced during the full production year at the Medusa and Habanero fields in the deepwater Gulf of Mexico more than offset declines at other more mature fields. Sales volumes in 2004 were unfavorably affected by Hurricane Ivan which temporarily shut-in most production in the Central Gulf of Mexico and severely damaged certain facilities, such as at the Tahoe field in Viosca Knoll Block 783, which was shut in for the entire fourth quarter 2004 following the storm. Natural gas sales volumes in Canada were 10.3 million cubic feet per day in 2005, 14 million in 2004 and 19.9 million in 2003. These were annual decreases of 26% in 2005 and 30% in 2004 and were mostly due to normal field decline at Rimbey area wells. Natural gas sales volumes in the United Kingdom in 2005 of 9.4 million cubic feet per day were up 37% with most of the increase due to higher sales volumes at the Amethyst field primarily caused by make-up gas sold in 2005 that related to a prior year’s contract. Natural gas sales in the U.K. were down from 9.6 million cubic feet per day in 2003 to 6.9 million cubic feet in 2004. The 28% decrease in 2004 was due to normal declines at the Amethyst field in the U.K. North Sea.

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. Murphy realized an average worldwide crude oil and condensate sales price of $45.25 per barrel in 2005, a 26% increase from the 2004 realized average price of $35.92 per barrel. The 2004 average sales price was 37% higher than the 2003 average price of $26.15 per barrel. The worldwide average price in 2003 was reduced $2.00 per barrel by the effects of the Company’s hedging program. The Company had hedged the sales price in 2003 for most of its heavy oil production in Canada and light oil production in the U.S., as well as a portion of its offshore and synthetic crude production in Canada. The average realized price in 2005 for crude oil and condensate sold in the U.S. was $47.48 per barrel, an increase of 34% over 2004. The average price for 2005 Canadian heavy oil sales was $21.30 per barrel, up 5% from 2004, and was adversely affected by higher costs of diluent and a wider heavy oil discount in the year. The average selling price for Hibernia and Terra Nova production offshore eastern Canada was $51.37 per barrel, an increase of 40%. Synthetic oil production sales price rose 44% in 2005 and averaged $58.12 per barrel. Sales prices for U.K. North Sea oil was up 43% to $52.83 per barrel. Ecuador sales prices averaged $32.54 per barrel in 2005 and Malaysia prices were $46.16 per barrel; these prices increased 31% and 12%, respectively. Malaysian prices were unfavorably affected by price sharing payments required in periods of high oil prices in accordance with the terms of the production sharing contract for Block SK 309.

The average oil sales price in 2004 in the U.S. was $35.35 per barrel, up 46% from 2003. Canadian heavy oil prices increased 64% in 2004 and averaged $20.26 per barrel. The Company’s sales price for production from the Hibernia and Terra Nova fields averaged $36.60 per barrel in 2004, up 35% versus 2003. Synthetic oil production at Syncrude averaged $40.35 per barrel in 2004, 62% higher than in 2003. Murphy’s U.K. North Sea oil production was sold at an average of $36.82 per barrel in 2004, 24% higher than 2003. Oil production in 2004 sold for $24.78 per barrel in Ecuador and $41.35 per barrel in Malaysia, increases of 8% and 41%, respectively. No sales occurred from Block 16 in Ecuador during the second half of 2004 due to a dispute with the field's operator over Murphy's new transportation and marketing arrangements. Because of the lack of sales, the Company's Ecuador operations did not benefit from higher average oil prices during the last six months of 2004.

In association with the higher oil prices, the sales prices for natural gas also strengthened in the Company's gas producing markets during each of the past two years. In 2005, the Company's sales price of North American natural gas averaged $8.44 per thousand cubic feet (MCF), an increase of 33% from 2004. In the U.K., the average sales price for natural gas was $5.80 per MCF, up 28% from 2004.

The average 2004 realized sales price for North American natural gas was $6.34 per MCF, 24% higher than the previous year. The 2003 price was reduced by $.21 per MCF because of the Company's hedging program in the U.S. and Canada. Natural gas sales prices in the U.K. were up 29% in 2004 to $4.52 per MCF.

Based on 2005 sales volumes and deducting taxes at marginal rates, each $1 per barrel and $.10 per MCF fluctuation in prices would have affected earnings from exploration and production operations by $24.3 million and $2.1 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 $305.4 million in 2005, $249 million in 2004 and $189.6 million in 2003. These amounts are shown by major operating area on pages F-36 and F-37 of this Form 10-K report. Costs per equivalent barrel excluding discontinued operations during the last three years are shown in the following table.

(Dollars per equivalent barrel)	2005	2004	2003
United States	**$ 5.17**	6.14	5.58
Canada			
Excluding synthetic oil	**4.40**	3.06	2.64
Synthetic oil	**25.09**	18.05	16.43
United Kingdom	**5.10**	4.25	4.69
Malaysia	**6.98**	5.63	3.44
Ecuador	**7.07**	11.18	9.05
Worldwide – excluding synthetic oil	**5.31**	4.89	4.11

The lower cost per equivalent barrel in the United States in 2005 was primarily due to start-up of the Front Runner field in late 2004 and sale of higher-cost properties in the Gulf of Mexico in mid-2005. The higher costs in the United States in 2004 were due primarily to lower production and higher costs for properties on the continental shelf of the Gulf of Mexico. The increase in costs in Canada excluding synthetic oil in 2005 was due to a growing heavy oil production profile, lower production volume at the Terra Nova field and a higher foreign exchange rate. Higher average Canadian costs excluding synthetic oil in 2004 were caused by lower natural gas production and a higher average foreign exchange rate. The higher rate per barrel for Canadian synthetic oil operations in 2005 was due to higher maintenance, energy and compensation costs coupled with lower production and a higher foreign exchange rate, while the increase in unit costs for synthetic oil operations in 2004 was attributable to a combination of higher maintenance and energy costs and a higher foreign exchange rate. The higher average U.K. cost in 2005 was mostly due to higher maintenance costs and lower production at the Schiehallion and Mungo/Monan fields. Lower average cost in the U.K. in 2004 was mainly due to sale of the high-cost "T" Block property during the year. The increase in the unit rate in Malaysia in 2005 was due to higher fuel and export duty costs, while the rate increase in 2004 was primarily due to higher manpower, fuel and export duty costs. Lower average costs per barrel in Ecuador in 2005 was due mostly to a new, less expensive arrangement for pipeline transportation that began near year-end 2004. The increase per unit in Ecuador in 2004 was mostly attributable to higher transportation costs associated with the heavy oil pipeline that commenced operations in the second half of 2003.

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-36 and F-37 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)	2005	2004	2003
Exploration and production			
Dry holes	**$ 126.0**	110.9	60.6
Geological and geophysical	**73.4**	28.4	31.2
Other	**10.2**	8.6	6.1
	209.6	147.9	97.9
Undeveloped lease amortization	**22.8**	16.4	14.7
Total exploration expenses	**$ 232.4**	164.3	112.6

Dry holes expense was up $15.1 million in 2005 compared to 2004 as higher unsuccessful exploratory drilling costs in the latest year offshore the Republic of Congo and Malaysia were only partially offset by lower costs in the deepwater Gulf of Mexico and offshore eastern Canada. Dry hole costs were $50.3 million higher in 2004 than 2003 because of more costs for unsuccessful drilling on the Scotian Shelf offshore eastern Canada, and in Block K Malaysia. Geological and geophysical (G&G) expenses were higher by $45 million in 2005 mostly due to more 3-D seismic acquisition and processing costs in Blocks SK 309/311 and PM 311/312, offshore Malaysia. G&G expenses were $2.8 million lower in 2004, mostly due to less seismic acquisition and interpretation work offshore eastern Canada, partially offset by seismic costs incurred in Malaysia. Other exploration expenses were $1.6 million higher in 2005 due mostly to more administrative costs in the Republic of Congo. Other exploration expenses were $2.5 million higher in 2004 than 2003 mainly due to more costs for Gulf of Mexico annual lease rentals and higher charges for work commitments on leases on the Scotian Shelf offshore eastern Canada. Undeveloped leasehold amortization increased by $6.4 million in 2005 and $1.7 million in 2004 because of lease acquisitions in each year in the Gulf of Mexico, a lease relinquishment in the Gulf of Mexico in 2005 and the acquisition in 2004 of two exploration concessions in the deep waters offshore the Republic of Congo.

Costs of $18.8 million and $2.6 million were incurred in 2005 and 2004, 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. In 2004, the Company also recorded costs of $12.6 million for retrospective insurance premiums related to past claims experience of an insurance provider.

Depreciation, depletion and amortization expense related to exploration and production operations totaled $319.1 million in 2005, $241.5 million in 2004 and $198.6 million in 2003. The $77.6 million increase in 2005 versus 2004 was due to more crude oil production and larger per barrel costs in most areas generally caused by incurring higher capital costs to find and develop oil and natural gas reserves. The Company continues to experience higher drilling and related costs caused by a greater demand for such services based on the currently strong prices for oil and natural gas. The $42.9 million increase in 2004 compared to 2003 was caused primarily by higher production at the Medusa and Habanero fields in the deepwater Gulf of Mexico and the West Patricia field in Block SK 309 Malaysia.

The exploration and production business recorded expenses of $9.6 million in 2005, $9.9 million in 2004 and $9.7 million in 2003 for accretion on discounted abandonment liabilities following the adoption of SFAS No. 143 on January 1, 2003. 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.

A property impairment charge of $3 million was recorded in 2003 to writedown the cost of a natural gas field in the Gulf of Mexico due to a reserve reduction caused by poor well performance.

The effective income tax rate for exploration and production operations was 39.1% in 2005, 32.7% in 2004 and 31.2% in 2003. 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. Each main exploration area in Malaysia is currently ring-fenced and no tax benefits have thus far been recognized for costs incurred for Block H, offshore Sabah, and Blocks PM 311/312, offshore Peninsula Malaysia. The effective tax rates in 2004 and 2003 were lower than the U.S. statutory rate partially due to recognition of deferred income tax benefits in Malaysia in each year. The 2004 deferred tax benefit of $31.9 million arose due to the expectation that temporary differences associated with exploration and other expenses incurred to-date in Block K Malaysia will be utilized to reduce future taxable income, and a deferred tax benefit of $11.4 million was recognized in 2003 for similar circumstances in Malaysia Blocks SK 309/311. These benefits had not been recognized in the income statement in previous years because the Company had established a deferred tax valuation allowance until such time that it became probable that these expenses would be utilized as deductions to reduce future taxable income. In 2004, Alberta reduced its tax rate for oil and gas companies, and in 2003, both the Federal and Alberta governments of Canada reduced their tax rates for oil and gas companies. These rate reductions led to recognition of tax benefits of $4.9 million in 2004 and $10.1 million in 2003, mostly due to reducing recorded deferred income tax liabilities.

At December 31, 2005, approximately 42% of the Company's U.S. proved oil reserves and 58% 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 deepwater Gulf of Mexico fields. About 43% of undeveloped reserves relate to the Front Runner field, which came on stream in December 2004. Further drilling and well workovers will be required to move undeveloped reserves to developed at Front Runner. In addition, all oil reserves for the Kikeh field in Block K Malaysia of 38.9 million barrels at year-end 2005 are undeveloped, pending completion of facilities and development drilling prior to first oil, which is projected to occur in the second half of 2007. On a worldwide basis, the Company has spent approximately $378 million in 2005, $272 million in 2004 and $280 million in 2003 to develop proved reserves. The Company expects to spend about $660 million in 2006, $511 million in 2007 and $243 million in 2008 to move currently undeveloped proved reserves to the developed category.

Refining and Marketing – The Company's refining and marketing (R&M) operations generated profits of $125.3 million in 2005 and $81.9 million in 2004, after posting a loss of $11.2 million in 2003. In 2005, stronger R&M margins in both North America and the U.K. contributed to the 53% increase in profits compared to 2004. In North America, income contribution improved 60% mostly due to stronger marketing profits, while in the U.K., income improved 40% due to stronger profits in both refining and marketing.

In 2004, R&M operating results improved markedly compared to 2003 because of a higher gross margin from product sales in both the North American and U.K. markets. Although the price of crude oil, the primary refinery feedstock, was much more costly during 2004 than in 2003, the supplies of gasoline and certain other products remained tight during much of the year, resulting in refining margins that were much stronger during 2004 in both the United States and United Kingdom.

Geographically, the North American R&M operations had income of $85.5 million in 2005 and $53.4 million in 2004 after incurring a loss of $21.2 million in 2003. North American operations include refining activities in the United States and marketing activities in the United States and Canada. The operating results for the Company's North American refining business were only slightly better in 2005 compared to 2004 as improved margins in the first eight months of 2005 prior to Hurricane Katrina were mostly offset by uninsured damages and higher insurance and other hurricane-related costs in the last four months of the year. Throughout the industry, refining margins in North America were generally stronger in 2005 versus 2004 due to a robust U.S. economy that fueled demand and the effects of hurricanes in the U.S. that forced closure of several refineries (including the Company's Meraux, Louisiana plant), which temporarily limited supply of refined products. Because the Meraux refinery was damaged by floodwaters caused by Hurricane Katrina and was shut down for the last four months of 2005 for repairs, the Company did not capture refining margins at Meraux during the period of strongest profits in 2005. The refinery is expected to be back in operation early in the second quarter of 2006. In addition, uninsured repair costs and higher insurance costs in the wake of U.S. hurricanes led to incremental costs of about $26.8 million in North America. The Company anticipates incurring additional uninsured repair costs in the first half of 2006 at the Meraux plant. Operating results for the North American retail gasoline chain were stronger in 2005 compared to 2004 due to a combination of larger per-gallon margins, higher average sales volume at each station for both fuel and non-fuel products and the continued addition of sites. The Company continued to increase the size of its retail fuel operations in North America by adding 112 Murphy USA fueling stations in the parking lots of Wal-Mart Supercenters in a 21-state area. This resulted in a 15% increase in the number of stores at year-end 2005 versus the prior year.

In 2004, the Meraux refinery ran more efficiently than in 2003, and therefore, the costs of operations were spread over a larger number of crude oil barrels, benefiting margins on a per-unit basis. Murphy also enjoyed better profits in 2004 than in 2003 from its Murphy USA retail station chain, essentially due to a combination of higher volumes sold, higher prices and lower operating costs per gallon sold. The Company added 129 stations to its chain during 2004, an increase of 21% over the number of sites at year-end 2003.

Unit margins (sales realizations less costs of crude oil and other feedstocks, refinery operating and depreciation expenses and transportation to point of sale) averaged $2.96 per barrel in North America in 2005, $2.25 in 2004 and $1.60 in 2003. North American refined product sales volumes increased 7% to a record 322,171 barrels per day in 2005, following a 31% increase in 2004. Sales volumes through the Company's retail gasoline chain at Wal-Mart Supercenters grew steadily each year, with the average volume per store increasing 9% in 2005 following a 6% rise in 2004.

Operations in the United Kingdom generated a record profit of $39.8 million in 2005, compared to $28.5 million in 2004 and $10 million in 2003. The U.K. operation experienced its most profitable year in 2005 due to significantly improved refinery margins and slightly stronger marketing margins. The U.K. R&M business also expanded the size of its retail fueling operations by purchasing 68 existing stations during 2005.

Unit margins in the United Kingdom averaged $6.36 per barrel in 2005, $4.85 per barrel in 2004 and $2.86 per barrel in 2003. Sales of refined petroleum products were down 4% in 2005 following a 6% increase in 2004. The decline in 2005 was primarily caused by a turnaround during the year at the Milford Haven, Wales refinery. The 2004 increase was primarily caused by higher volumes sold in both the retail and cargo market.

Based on sales volumes for 2005 and deducting taxes at marginal rates, each $.42 per barrel ($.01 per gallon) fluctuation in the unit margins would have affected annual refining and marketing profits by $34.5 million. The effect of these unit margin fluctuations on consolidated net income cannot be measured precisely because operating results of the Company's exploration and production segments could be affected differently.

Corporate – The costs of corporate activities, which include interest income, interest expense, foreign exchange gains and losses, and corporate overhead not allocated to operating functions, were $35.5 million in 2005, $97.8 million in 2004 and $13.8 million in 2003. Net after-tax corporate costs were $62.3 million lower in 2005 compared to 2004. The improvement in 2005 was attributable to favorable income tax benefits, higher interest income, lower net interest expense and more favorable foreign exchange impacts. These favorable effects were partially offset by higher administrative expenses in 2005. Income taxes were favorable by $23 million in the corporate area in 2005 due to lower net pretax costs and income tax benefits of $9.7 million, mostly due to refund and settlement of prior year income tax matters in the United States. In 2004, the Company incurred tax costs of $27.5 million for a 5% withholding tax on a dividend from a Canadian subsidiary. Interest income was favorable by $3.8 million in 2005 due mainly to interest received on the 2005 U.S. income tax refunds. Interest expense, net of amounts capitalized to various development projects, was $25.3 million lower in 2005 than in 2004. Interest expense incurred was $8.9 million less in 2005 due to lower average borrowing levels, while amounts capitalized to major development projects such as the Syncrude expansion and Kikeh development increased by $16.4 million. The effects of foreign exchange resulted in an after-tax expense of $18.6 million in 2004, but these effects were insignificant in 2005. The unfavorable result for foreign exchange in 2004 was caused by a significant weakening of the U.S. dollar against the Canadian dollar, pound sterling and Euro currencies during that year. Administrative expenses in the corporate area were $15 million higher in 2005 than in 2004. The cost increase in 2005 was mostly attributable to higher executive compensation expense and higher salaries and benefits, with partial offsets due to lower Sarbanes-Oxley compliance consulting costs.

Net after-tax corporate costs in 2004 were $84 million higher than in 2003, with the increase related to unfavorable foreign exchange losses, higher administrative costs, higher net interest expense and unfavorable income taxes. Higher interest income in 2004 partially offset these unfavorable variances. Due to a much weaker U.S. dollar compared to the Canadian dollar, pound sterling and Euro in 2004, the Company incurred after-tax losses of $18.6 million for foreign exchange in 2004 compared to a $5.4 million profit in 2003. The exchange losses were mostly caused by foreign subsidiaries with non-U.S. dollar functional currencies holding a significant amount of U.S. dollars that weakened against these other currencies during the last half of 2004. Administrative expenses were $8.5 million higher in 2004 than in 2003, mostly due to higher costs of corporate compliance under the Sarbanes-Oxley Act and higher executive compensation and salaries and benefits. Net interest expense was $13.5 million higher in 2004 than in 2003, mostly due to lower interest being capitalized on U.S. oil and gas developments and U.S. refinery expansion projects. Income tax expense in 2004 was unfavorable by $43 million in the corporate area primarily due to a $27.5 million withholding tax incurred on a $550 million dividend paid to the Company by its Canadian subsidiary, and a $20.1 million tax benefit in 2003 from settlement of previous years' income tax audit issues. The Company earned $13.3 million more interest income in 2004 mostly related to holding larger balances of invested cash for a portion of the year after selling most of its conventional oil and gas properties in western Canada.

Capital Expenditures

As shown in the selected financial data on page 11 of this Form 10-K report, capital expenditures for continuing operations, including exploration expenditures, were $1,329.8 million in 2005 compared to $975.4 million in 2004 and $906.1 million in 2003. These amounts included $209.6 million, $147.9 million and $97.9 million of exploration costs that were expensed. Capital expenditures for exploration and production activities totaled $1,092 million in 2005, 82% of the Company's total capital expenditures for the year. Exploration and production capital expenditures in 2005 included $34.5 million for acquisition of undeveloped leases, $404.5 million for exploration activities, and $652.9 million for development projects. Development expenditures included $58.7 million for deepwater discoveries in the Gulf of Mexico; $264.5 million for the West Patricia and Kikeh fields in Malaysia; $112.9 million for synthetic oil expansion and other capital at the Syncrude project in Canada; $111.1 million for western Canada heavy oil and natural gas projects; and $37 million for the Terra Nova and Hibernia oil fields, offshore Newfoundland. Exploration and production capital expenditures are shown by major operating area on page F-35 of this Form 10-K report.

Refining and marketing capital expenditures totaled $202.4 million in 2005, compared to $134.7 million in 2004 and $215.4 million in 2003. These amounts represented 15%, 14% and 24% of capital expenditures for continuing operations of the Company in 2005, 2004 and 2003, respectively. Refining capital spending was $34.1 million in 2005 compared to $46.1 million in 2004 and $130.8 million in 2003. In 2004, the Company completed the construction of a green gasoline unit at its Superior, Wisconsin refinery. In 2003, the expansion of the Meraux, Louisiana refinery was completed, including building a hydrocracker unit to meet future clean fuel specifications and increasing the crude oil processing capacity of the plant to 125,000 barrels per day. Capital expenditures on the Superior refinery green gasoline unit were $18 million in 2004 and $5.5 million in 2003. Capital expenditures related to the Meraux expansion project amounted to $5.5 million in 2004 and $69 million in 2003. Marketing expenditures amounted to $168.2 million in 2005, $88.6 million in 2004 and $84.6 million in 2003. The majority of marketing expenditures in each year was related to construction of retail gasoline stations at Wal-Mart Supercenters in 21 states in the U.S. The Company added 112 total stations to this retail station network in 2005, 129 in 2004 and 119 in 2003. In 2005, the Company also purchased 68 retail fueling stations in the U.K., thereby expanding its company-owned retail station count by 70%.

Cash Flows

Cash provided by continuing operations was $1,216.7 million in 2005, $1,035.1 million in 2004 and $501.1 million in 2003. The increase in cash provided in each of the last two years compared to the immediately preceding year was primarily due to higher crude oil and refined product sales volumes, and higher sales prices for crude oil, natural gas and refined products. Cash provided by continuing operations was reduced by expenditures for refinery turnarounds and abandonment of oil and gas properties totaling $31.9 million in 2005, $18.6 million in 2004 and $66.1 million in 2003. A scheduled refinery turnaround occurred at Milford Haven in 2005 and at both U.S. refineries in 2003.

Cash proceeds from property sales other than from discontinued operations were $172.7 million in 2005, $60.4 million in 2004 and $188.6 million in 2003. The 2005 proceeds were mainly 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. The 2004 property sales included the disposal of the "T" Block field in the U.K. North Sea and certain U.S. onshore gas properties and U.S. marketing terminals, while 2003 included disposal of the Ninian and Columba fields in the U.K. and various oil and gas assets in Canada and the Gulf of Mexico. Property sales which have been classified as discontinued operations brought in net cash proceeds of $583 million in 2004, and included sale of most of the Company's conventional oil and gas properties in western Canada. During 2003, the Company borrowed $309.7 million under notes payable and other long-term debt arrangements primarily to fund a portion of the Company's development capital expenditures. Maturity of U.S. government securities provided cash of $17.9 million in 2005. Cash proceeds from stock option exercises and employee stock purchase plans amounted to $26.5 million in 2005, $3.2 million in 2004 and $3.6 million in 2003.

Property additions and dry hole costs used cash of $1,246.2 million in 2005, $938.4 million in 2004 and $868.9 million in 2003. The increase in 2005 was mainly caused by development activities at the Kikeh field offshore Sabah, Malaysia, and acquisition of 68 retail fueling stations in the U.K. In 2004, the increases were primarily due to a heavy oil property acquisition in Canada, plus higher heavy oil development spending and higher exploration drilling in Malaysia. Cash used in other investing activities of $9.9 million in 2005 primarily related to advances under future equipment rental agreements in Malaysia. The Company repaid debt of $50.6 million in 2005 using a combination of internal cash flow and proceeds from sale of assets. Total paydown of debt was $495 million during 2004 and was mostly accomplished using a portion of the proceeds of asset dispositions classified as discontinued operations. Cash outlays for debt repayment during 2003 were $76.8 million. Cash of

$17.9 million was invested in 2004 in U.S. government securities with maturities greater than 90 days. Cash used for dividends to stockholders was $83.2 million in 2005, $78.2 million in 2004 and $73.5 million in 2003. The Company raised its annualized dividend rate from $.40 per share to $.45 per share beginning in the third quarter of 2004.

Financial Condition

Year-end working capital (total current assets less total current liabilities) totaled $551.9 million in 2005, $424.4 million in 2004 and $228.5 million in 2003. 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 $361.3 million below fair value at December 31, 2005. Cash and cash equivalents at the end of 2005 totaled $585.3 million compared to $535.5 million a year ago and $252.4 million at the end of 2003.

The long-term portion of debt was reduced by $3.8 million during 2005 and totaled $609.6 million at the end of 2005, which represented 15% of total capital employed. Long-term debt included $11.6 million of nonrecourse debt borrowed in connection with the Hibernia oil field development. Long-term debt declined by $477 million in 2004 as the Company utilized the proceeds of asset dispositions in western Canada to pay down debt. Stockholders’ equity was $3.46 billion at the end of 2005 compared to $2.65 billion a year ago and $1.95 billion at the end of 2003. 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 2005 balance sheet compared to 2004 included a $162.2 million increase in accounts receivable, which was caused by higher sales volumes of crude oil and refined petroleum products at higher average prices near the end of 2005 compared to 2004, and amounts recoverable from insurance companies at year-end 2005. These amounts recoverable from insurance companies mostly related to hurricane-related repair costs at the Meraux refinery. Inventory values were $19.1 million more at year-end 2005 than in 2004 mostly because of more crude oil barrels in storage at the Meraux refinery and more drilling equipment held in inventory in Malaysia. Prepaid expenses declined $12.5 million due to refund of prior years’ U.S. income taxes due from the IRS. Short-term deferred income tax assets increased $8.9 million at year-end 2005 due mostly to a deferred tax benefit recorded in 2005 in the Company’s U.K. downstream business caused by a higher short-term temporary difference for the LIFO inventory allowance in the current period. Net property, plant and equipment increased by $688.6 million in 2005 as capital expenditures during the year were larger than the book values of properties sold and the additional depreciation and amortization expensed. Goodwill related to the acquisition of Beau Canada in 2000 increased by $.6 million in 2005 primarily due to a higher Canadian dollar exchange rate in the current year. Deferred charges and other assets increased $11.4 million in 2005 due mostly to prepayments on future asset rentals for the Kikeh field in Malaysia. Current maturities of long-term debt declined by $46.2 million primarily because of paydown of loans used to partially fund the Beau Canada acquisition in 2000. Accounts payable rose by $277.9 million mostly due to the higher costs of purchased crude oil and gasoline at year-end 2005 compared to 2004 and higher amounts owed on exploration and production capital projects. Income taxes payable decreased $136.1 million at year-end 2005 due to a combination of paying higher tax installments in 2005 and settlement of a tax liability with the Canadian tax authorities in 2005. Other taxes payable decreased $33.7 million mostly due to lower sales, use and excise taxes owed at year-end 2005 compared to 2004 primarily caused by the Meraux refinery being down for repairs at the end of the year. Deferred income tax liabilities increased $37 million in 2005 due mostly to higher accelerated depreciation deductions taken in tax returns based on 2005 capital expenditures. The liability associated with asset retirements dropped by $25.1 million mostly due to purchasing companies accepting responsibility for the abandonment liabilities associated with oil and gas properties sold by the Company on the continental shelf of the Gulf of Mexico during 2005. Accrued major repair costs increased by $11.1 million primarily based on accruing additional costs for future turnarounds of the Company’s three refineries, which exceeded the amounts expended in 2005 at the Milford Haven refinery turnaround that were charged against this liability.

Murphy had commitments for future capital projects of $932 million at December 31, 2005, including $57 million for costs to develop deepwater Gulf of Mexico fields, $585 million for field development and future work commitments in Malaysia, $69 million for exploration drilling in the Republic of Congo and $73 million for future work commitments on the Scotian Shelf offshore eastern Canada.

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, 2005, the Company had access to long-term revolving credit facilities in the amount of $1 billion. No amounts were borrowed under these revolving facilities at year-end 2005. The credit facilities were renewed and increased by $300 million in mid-2005. The most restrictive covenants under these existing facilities limit the Company’s long-term debt to capital ratio (as defined in the agreements) to 60%. At December 31, 2005, the long-term debt to capital ratio was approximately 15%. The Company also has available uncommitted credit lines of approximately $774 million at December 31, 2005. 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 E to the consolidated financial statements. The Company anticipates utilizing about $100 million of its long-term borrowing capacity in 2006 to fund certain development projects, including the Kikeh field in Malaysia. Such borrowing amounts are subject to change based on actual levels of cash flows and capital spending. At March 1, 2006, the Company’s long-term debt rating by Standard & Poor’s was “A-” and by Moody’s Investors Service was “Baa1”. On February 21, 2006, Moody’s placed its rating of the Company under review for possible downgrade. The Company’s ratio of earnings to fixed charges was 24.7 to 1 in 2005, 13.4 to 1 in 2004 and 6.1 to 1 in 2003.

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 addresses historic contamination and imposes 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 at the owner's property. 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 enters commerce or is used. Several states have passed similar or more stringent regulations governing the formulation of motor fuels. The EPA's standard for highway diesel fuel sulfur limits becomes effective for the Company in 2006.

World leaders have held numerous discussions about the level of worldwide greenhouse gas emissions. As part of these discussions, a 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 early 2005 and these countries 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 62 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 U.S. Environmental Protection Agency (EPA) currently considers the Company to be a Potentially Responsible Party (PRP) at two Superfund sites. The potential total cost to all parties to perform necessary remedial work at these sites may be substantial. 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, 2005.

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 $3.5 million in 2005. 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 $53.2 million in 2005 and are projected to be $63.1 million in 2006.

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 two years, prices for oil field goods and services have risen and 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.

Accounting changes and recent accounting pronouncements – As described in Note G on page F-14 of this Form 10-K report, Murphy adopted the Financial Accounting Standards Board's (FASB) Statement of Financial Accounting Standards (SFAS) 143, Accounting for Asset Retirement Obligations, effective January 1, 2003. Upon adoption of SFAS No. 143, the Company recorded an after-tax charge of $7 million, which was reported as the cumulative effect of a change in accounting principle.

The FASB has issued SFAS No. 123 (revised 2005), Share Based Payment, which replaces SFAS No. 123, Accounting for Stock-Based Compensation, and supersedes APB Opinion No. 25, Accounting for Stock Issued to Employees. SFAS No. 123 (revised 2005) 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 statement will be effective for the Company beginning January 1, 2006. Although the Company used the intrinsic-value approach of Accounting Principles Board No. 25 to account for stock options through year-end 2005, it provided pro forma disclosures in Note A as if SFAS No. 123 was currently being applied. The Company expects to use the modified prospective transition method upon adoption of SFAS 123 (revised). Stock option awards are expected to qualify for accounting as equity awards. The adoption of this statement will increase compensation expense in the consolidated statement of income beginning in 2006 by including cost for the Company's stock options and Employee Stock Purchase Plan. The Company has preliminarily estimated this incremental expense to be $10 million in 2006.

The FASB has issued FASB Staff Position (FSP) 19-1, Accounting for Suspended Well Costs, to provide guidance on the accounting for exploratory well costs and to amend SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies. 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 beginning in April 2005 on a prospective basis to existing and newly-capitalized exploratory wells costs. See Note D to the consolidated financial statements. The adoption of this FSP did not have any effect on the Company's net income or financial condition.

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 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 benefits 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 in 2005. The Company recorded a tax benefit of $3.5 million in 2005 related to the Act.

The Emerging Issues Task Force of the FASB has issued EITF 03-13, Applying the Conditions in Paragraph 42 of SFAS No. 144 in Determining Whether to Report Discontinued Operations. The EITF generally believes that current practice with respect to applying the criteria in paragraph 42 of SFAS No. 144 has not been applied consistently and has not resulted in broadening the reporting of asset dispositions as discontinued operations. EITF 03-13 contains further guidance for evaluating the cash flows of the component sold and what constitutes significant continuing involvement. In certain industries, EITF 03-13 may lead to more asset disposals being reported as discontinued operations in future periods. However, in the oil and gas industry, it may cause more asset disposals to continue to be classified as continuing operations due to clarification of what constitutes continuing involvement. This standard was adopted by the Company for all asset disposal transactions occurring after January 1, 2005.

SFAS No. 151, Inventory Costs, was issued by the FASB in November 2004. This statement amends Accounting Research Bulletin No. 43, to clarify that abnormal amounts of idle facility expense, freight, handling costs, and wasted materials should be recognized as current-period charges, and it also requires that allocation of fixed production overheads be based on the normal capacity of the related production facilities. The provisions of this statement will be effective on a prospective basis beginning January 1, 2006, and the Company does not expect the adoption of this statement to have a significant impact on its results of operations.

The FASB issued SFAS No. 153, Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29, in December 2004. This statement addressed the measurement of exchanges of nonmonetary assets and eliminated the exception from fair value measurement for nonmonetary exchanges of similar productive assets and replaced it with an exception for exchanges that do not have commercial substance. SFAS No. 153 was adopted by the Company on a prospective basis for nonmonetary asset exchanges occurring after June 30, 2005. The adoption of this statement did not have a significant impact on the Company's results of operations in 2005.

In March 2005, the FASB issued FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations, an interpretation of SFAS No. 143. This interpretation clarifies the term conditional asset retirement obligation as used in SFAS No. 143 and when a company would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. This interpretation was adopted by the Company during the fourth quarter of 2005 and it had no impact on the Company's results of operations for 2005.

In March 2005, the EITF decided in Issue 04-6, Accounting for Stripping Costs Incurred during Production in the Mining Industry, 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 operations at Syncrude may be affected by this ruling. The EITF consensus is effective for the Company as of January 1, 2006 and any adjustment required as of the effective application date will be recorded as a cumulative effect of a change in accounting principle. The Company does not currently expect the adoption of this consensus to have a significant impact on its financial statements.

In September 2005, the EITF decided in Issue 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty, that two or more exchange transactions involving inventory with the same counterparty that are entered into in contemplation of one another should be combined for purposes of evaluating the effect of APB Opinion 29, Accounting for Nonmonetary Transactions. Additionally, the EITF decided that a nonmonetary exchange where an entity transfers finished goods inventory in exchange for the receipt of raw materials or work-in-progress inventory within the same line of business should generally be recognized by the entity at fair value. This consensus will be applied to new arrangements entered into beginning April 1, 2006, and to all inventory transactions that are completed after December 15, 2006, for arrangements entered into prior to March 15, 2006. The Company does not expect the adoption of this consensus to have a significant impact on its financial statements.

In 2005, the FASB added to its agenda a reconsideration of accounting and disclosures rules related to retirement and postretirement plans. The FASB has stated that it will first consider whether the funded status of benefit plans should be reported as an asset or liability on the plan sponsor's balance sheet. The FASB's reconsideration of all other aspects of the accounting for retirement and postretirement plans will follow thereafter. The FASB's goal is to conclude as to the first matter with any accounting changes required by the end of 2006. The Company is unable to predict the changes to its accounting policies and disclosures, or the applicable timing thereof, that may arise upon completion of this FASB review.

Other – Murphy holds a 20% interest in Block 16 Ecuador, where the Company and its partners produce oil for export. In 2001, the local tax authorities announced that Value Added Taxes (VAT) paid on goods and services related to Block 16 and many oil fields held by other companies will no longer be reimbursed. In response to this announcement, oil producers have filed actions in the Ecuador Tax Court seeking determination that the VAT in question is reimbursable. In July 2004, international arbitrators ruled that VAT was recoverable by another oil company, but the State of Ecuador responded that it was not bound by this arbitral decision. As of December 31, 2005, the Company has a receivable of approximately $15.3 million related to VAT. Murphy believes that its claim for reimbursement of VAT under applicable Ecuador tax law is valid, and it does not expect that the resolution of this matter will have a material adverse affect on the Company's net income, financial condition or liquidity 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 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 often 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 often 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-33 and F-34 of the annual report. The U.S. oil reserve revision in 2005 was mostly due to poor well performance at the deepwater Front Runner 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. The reserve revision for U.S. oil in 2004 related primarily to loss of royalty relief for the Medusa and Front Runner deepwater fields based on year-end 2004 oil prices. Oil reserve revisions in Canada in 2004 related to a combination of low heavy oil prices at year-end that restricted economic recoverability of certain heavy oil reserves and higher projected royalties at the Terra Nova and Hibernia fields. Oil reserve revisions in Ecuador in 2004 were caused by a higher than previously estimated water cut in the liquid stream produced at Block 16. Natural gas reserve revisions were positive in the U.S. in 2004 due to better well performance. 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 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 an exploration well in progress at year-end 2005 amounted to $6 million. Through February 2006, the well was determined to have successfully found hydrocarbon deposits.

  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 expenses related to wells drilled in prior years were $13.2 million in 2004; there were no dry holes in 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 Sheets 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 must be evaluated for impairment at least annually. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the amount of oil and natural gas that will be produced from a field, the timing of this future production, future costs to produce the oil

and natural gas, future capital and abandonment costs, and future inflation levels. The need to test a 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, 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. A description of impairment charges recorded during the last three years is included in Note D in the consolidated financial statements.

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 reserve 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 making impairment assessments for refining and marketing property and equipment, future margins for the refining and marketing business are generally projected based on historical results adjusted for known or expected changes in future operations. Although the Company is not aware of any property carrying values that are impaired at December 31, 2005, one or a combination of factors such as significantly lower future sales prices, significantly lower future production, significantly higher future costs, or significantly lower future margins for refining and marketing, 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.

- *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 property basis differences and liabilities for repairs, dismantlements and retirement benefits. The Company routinely evaluates all deferred tax assets to determine the likelihood of their realization. A valuation allowance has been recognized for deferred tax assets related to basis differences for Blocks H and PM 311/312 in Malaysia, 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 changes in AA-rated corporate bond rates. 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.

  Due to a reduction in bond yields during 2005, the Company has reduced the primary plans' discount rate from 6.00% in 2005 to 5.70% in 2006. Although the Company presently assumes a return on plan assets of 7.25% for the primary 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 returns. The effects of a lower discount rate and a growing employee population are expected to lead to higher pension expense in 2006. The Company's annual retirement plan expense is estimated to increase by about $2 million in 2006 compared to 2005. In 2005, the Company paid $26.4 million into various retirement plans, including a $14.5 million voluntary payment into the U.S. qualified retirement plan, and $3.5 million into postretirement plans. In 2006, the Company is expecting to fund payments of approximately $7.5 million into various retirement plans and $3.5 million for postretirement plans. The Company could be required to make additional and more significant funding payments to retirement plans in future years. 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 2006 annual retirement and postretirement expenses by $2.5 million and $.5 million, respectively, and a 0.5% decline in the assumed rate of return on plan assets would increase 2006 retirement expense by $1.5 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 2005 under such contractual obligations and arrangements are shown below.

	Amount of Obligation				
(Millions of dollars)	Total	2006	2007-2009	2010-2011	After 2011
Total debt including current maturities	$ 614.1	4.5	11.7	—	597.9
Operating leases	214.1	19.7	53.7	26.2	114.5
Purchase obligations	1,118.6	954.9	62.7	18.9	82.1
Other long-term liabilities	262.4	20.0	2.3	3.7	236.4
Total	$2,209.2	999.1	130.4	48.8	1,030.9

A floating, production, storage and offloading (FPSO) vessel is currently being built by other companies and it is anticipated to be used in producing the Kikeh field in Block K Malaysia, which is scheduled to start-up production in the second half of 2007. The Company will lease this FPSO subject to satisfactory completion of construction by its owners. Certain amounts to be paid by the Company through completion of the FPSO construction period totaling $29 million have been included in the contractual obligation table above in 2006 and 2007. If the FPSO is accepted by the Company in 2007, future undiscounted lease commitments will amount to $631 million; these amounts have not been included in the contractual obligation table above pending successful construction of the FPSO. Accounting treatment for this lease will be determined upon satisfactory delivery of the FPSO.

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, 2005 that expire in future periods is shown below.

	Amount of Commitment				
(Millions of dollars)	Total	2006	2007-2009	2010-2011	After 2011
Financial guarantees	$ 8.5	—	2.6	—	5.9
Letters of credit	50.2	9.3	40.8	0.1	—
Total	$58.7	9.3	43.4	0.1	5.9

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 2005 involve an oil and natural gas processing contract and a hydrogen purchase contract. 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. The Company has a contract to purchase hydrogen for the Meraux refinery through 2019. 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 both of 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 oil and natural gas, led to strong prices for these products during most of 2005 and into early 2006. Due to the volatility of worldwide crude oil and North American natural gas prices, routine monitoring of spending plans is required.

The Company's capital expenditure budget for 2006 was prepared during the fall of 2005 and based on this budget capital expenditures are expected to increase over 2005. Capital expenditures in 2006 are projected to total $1.6 billion. Of this amount, $1.35 billion or about 85%, is allocated for the exploration and production program. Geographically, E&P capital is spread approximately as follows: 20% for the United States, 55% for Malaysia, 10% for Canada and 15% for all other areas. Spending in the U.S. is dominated by exploration and appraisal drilling in the deepwater Thunderhawk area, plus early spending on an anticipated development of the Thunderhawk field. In Malaysia, over half of the spending is for continued development of the Kikeh field in Block K and the remainder includes exploration and development activities for other areas held by the Company. Spending in the Republic of Congo includes studies for development options for the Azurite Marine discovery offshore. Refining and marketing expenditures in 2006 should be about $225 million of which almost 90% is allocated to the U.S. The U.S. budget has funds for construction of additional retail gasoline stations at Wal-Mart Supercenters and pipeline and terminal investments needed to support this growing retail marketing system. Capital and other expenditures are routinely reviewed and planned capital expenditures may be adjusted to reflect differences between budgeted and actual cash flow during 2006. 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 certain development costs in 2006, primarily at the Kikeh field in Block K Malaysia, using available credit facilities. Most other funding is anticipated to be generated from operating cash flow. The Company forecasts a growth in long-term debt of approximately $100 million in 2006. 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. In early 2006, oil prices remained stronger than those forecast in the Company's 2006 budget, but natural gas prices had retreated to below budgeted levels. In early 2006, the Company was experiencing losses in its North American refining and marketing business due to actual margins being well below margin levels forecast in the budget.

The Company currently expects production in 2006 to be about 110,000 barrels of oil equivalent per day. Growth in oil volumes based on start-up of new coker facilities at Syncrude and an anticipated successful heavy oil development drilling program that is ongoing in western Canada is expected to be more than offset by lower volumes at Terra Nova due to more downtime for repairs, lower volumes allocable to Murphy at West Patricia under the production sharing contract, and decline at Front Runner in the deepwater Gulf of Mexico. Natural gas production will be favorably impacted by start-up of the Seventeen Hands field in the deepwater Gulf of Mexico, but other volumes in the deepwater Gulf of Mexico are likely to be lower prior to workovers and volumes in the U.K. are expected to be lower at the Amethyst field.

The repair of flood and wind damages at the Meraux refinery has been estimated to cost up to $200 million. Because of certain limitations on insurance policies for flooding, the Meraux refinery could have unrecoverable repair costs of up to $50 million in the first half of 2006. See Item 3 of this Form 10-K report for additional information regarding environmental and other contingencies relating to Hurricane Katrina.

The U.K. government announced in 2005 that the effective income tax rate on E&P earnings will increase from 40% to 50% beginning in 2006. As of December 31, 2005, the Company has not recognized the estimated charge of approximately $11 million to increase deferred income tax liabilities because the 10% rate increase has not been confirmed by the U.K. Parliament. This action is expected to be approved by Parliament and the unfavorable deferred tax adjustment is expected to be recorded in 2006.

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 natural gas price swap agreements at December 31, 2005 for a remaining notional volume of 720,000 MMBTU (1 MMBTU = 1 milion British Thermal Units) that are intended to hedge the financial exposure of its Meraux, Louisiana refinery to fluctuations in the future price of a portion of natural gas to be purchased for fuel in 2006. In each month of settlement, the swaps require Murphy to pay an average natural gas price of $3.35 per MMBTU and to receive the average NYMEX price for the final three trading days of the month. At December 31, 2005, the estimated fair value of these agreements was recorded as an asset of $5.2 million. A 10% increase in the average NYMEX price of natural gas would have increased this asset by $.8 million, while a 10% decrease would have reduced the asset by a similar amount.

At December 31, 2005, the Company was a party to forward sale contracts covering 4,000 barrels per day in heavy oil sales during 2006. The contracts are intended to hedge the financial exposure of the Company's heavy oil sales in Canada during the respective contract period and are priced at $25.23 per barrel in 2006. At December 31, 2005, the estimated fair value of these agreements was recorded as a liability valued at $24.3 million. A 10% increase in the price of Canadian heavy oil at the Hardisty terminal in Canada would have increased this liability by $6.1 million, while a 10% decrease would have decreased this liability by a similar amount.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages F-1 through F-40, which follow page 33 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. Based on our evaluation, management has concluded that our internal control over financial reporting was effective as of December 31, 2005. Our report is included on page F-2 of the annual report. Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 has been audited by KPMG LLP, an independent registered public accounting firm, and their report is included on page F-2 of this annual report.

There were no significant changes in the Company's internal controls over financial reporting that occurred during the fourth quarter of 2005 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 AND EXECUTIVE OFFICERS OF THE REGISTRANT

Certain information regarding executive officers of the Company is included on page 9 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 10, 2006 under the caption "Election of Directors."

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 10, 2006 under the captions "Compensation of Directors," "Executive Compensation," "Option Exercises and Fiscal Year-End Values," "Option Grants," "Compensation Committee Report for 2005," "Shareholder Return Performance Presentation" and "Retirement Plans."

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 10, 2006 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

None

Item 14. PRINCIPAL ACCOUNTANT 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 10, 2006 under the caption "Audit Committee Report."

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

2. Financial Statement Schedules

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

3. Exhibits – The following is an index of exhibits that are hereby filed as indicated by asterisk (*), that are 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 2, 2005	Exhibit 3.2 of Murphy's Form 8-K report filed February 4, 2005 under the Securities Exchange Act of 1934
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	
10.2	Employee Stock Purchase Plan as amended May 10, 2000	Exhibit 99.01 of Murphy's Form S-8 Registration Statement filed August 4, 2000 under the Securities Act of 1933
10.3	Murphy Vehicle Fueling Station Master Ground Lease Agreement	Exhibit 10.3 of Murphy's Form 10-K report for the year ended December 31, 2002
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	2005 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	
99.2	Form of employee restricted stock award	Exhibit 99.2 of Murphy's Form 10-K report for the year ended December 31, 2004
*99.3	Form of non-employee director stock option	
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, 2004

[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	/s/ CLAIBORNE P. DEMING Claiborne P. Deming, President	Date: March 15, 2006

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on March 15, 2006 by the following persons on behalf of the registrant and in the capacities indicated.

/s/ WILLIAM C. NOLAN JR. William C. Nolan Jr., Chairman and Director	/s/ IVAR B. RAMBERG Ivar B. Ramberg, Director
/s/ CLAIBORNE P. DEMING Claiborne P. Deming, President and Chief Executive Officer and Director (Principal Executive Officer)	/s/ NEAL E. SCHMALE Neal E. Schmale, Director
/s/ FRANK W. BLUE Frank W. Blue, Director	/s/ DAVID J. H. SMITH David J. H. Smith, Director
/s/ GEORGE S. DEMBROSKI George S. Dembroski, Director	/s/ CAROLINE G. THEUS Caroline G. Theus, Director
/s/ ROBERT A. HERMES Robert A. Hermes, Director	/s/ STEVEN A. COSSÉ Steven A. Cossé, Executive Vice President and General Counsel (Principal Financial Officer)
/s/ R. MADISON MURPHY R. Madison Murphy, Director	/s/ JOHN W. ECKART John W. Eckart, 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, 2005 and 2004, 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, 2005. 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, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, 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 G to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Murphy Oil Corporation's internal control over financial reporting as of December 31, 2005, 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 March 9, 2006 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Houston, Texas
March 9, 2006

REPORT OF MANAGEMENT – INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Management has conducted an evaluation of the effectiveness of our internal control over financial reporting based on the criteria set forth in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation management concluded that our internal control over financial reporting was effective as of December 31, 2005.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 has been audited by KPMG LLP, an independent registered public accounting firm, and their report is included below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of Murphy Oil Corporation:

We have audited management's assessment, included in the accompanying Report of Management – Internal Control Over Financial Reporting, that Murphy Oil Corporation maintained effective internal control over financial reporting as of December 31, 2005, 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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and 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, management's assessment that Murphy Oil Corporation maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, Murphy Oil Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Murphy Oil Corporation and subsidiaries as of December 31, 2005 and 2004, 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, 2005, and our report dated March 9, 2006, expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Houston, Texas
March 9, 2006

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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)*	2005	2004*	2003
Revenues			
Sales and other operating revenues	**$ 11,680,079**	8,299,147	5,094,518
Gain on sale of assets	**175,140**	69,594	61,524
Interest and other income (loss)	**21,932**	(8,902)	8,615
Total revenues	**11,877,151**	8,359,839	5,164,657
Costs and Expenses			
Crude oil and product purchases	**8,783,042**	6,153,413	3,678,729
Operating expenses	**848,647**	736,057	582,131
Exploration expenses, including undeveloped lease amortization	**232,400**	164,227	112,638
Selling and general expenses	**158,889**	132,329	119,538
Depreciation, depletion and amortization	**396,875**	321,446	258,857
Net costs associated with hurricanes	**66,770**	3,350	—
Impairment of long-lived assets	**—**	—	8,314
Accretion of asset retirement obligations	**9,704**	10,017	9,734
Interest expense	**47,304**	56,224	57,751
Interest capitalized	**(38,539)**	(22,160)	(37,240)
Total costs and expenses	**10,505,092**	7,554,903	4,790,452
Income from continuing operations before income taxes	**1,372,059**	804,936	374,205
Income tax expense	**534,156**	308,541	95,795
Income from continuing operations	**837,903**	496,395	278,410
Income from discontinued operations, net of tax	**8,549**	204,920	22,780
Income before cumulative effect of change in accounting principle	**846,452**	701,315	301,190
Cumulative effect of change in accounting principle, net of tax	**—**	—	(6,993)
Net Income	**$ 846,452**	701,315	294,197
Income per Common Share – Basic			
Income from continuing operations	**$ 4.54**	2.69	1.52
Income from discontinued operations	**.05**	1.12	.12
Cumulative effect of change in accounting principle	**—**	—	(.04)
Net Income – Basic	**$ 4.59**	3.81	1.60
Income per Common Share – Diluted			
Income from continuing operations	**$ 4.46**	2.65	1.50
Income from discontinued operations	**.05**	1.10	.12
Cumulative effect of change in accounting principle	**—**	—	(.03)
Net Income – Diluted	**$ 4.51**	3.75	1.59
Average Common shares outstanding – basic	**184,354,552**	183,972,642	183,692,642
Average Common shares outstanding – diluted	**187,889,378**	186,887,022	185,485,532

* Reclassified to conform to 2005 presentation.

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)*	2005	2004
Assets		
Current assets		
Cash and cash equivalents	**$ 585,333**	535,525
Short-term investments in marketable securities	**—**	17,892
Accounts receivable, less allowance for doubtful accounts of $14,508 in 2005 and $13,962 in 2004	**865,155**	702,933
Inventories, at lower of cost or market		
Crude oil and blend stocks	**83,265**	71,010
Finished products	**146,753**	155,295
Materials and supplies	**84,937**	69,540
Prepaid expenses	**33,239**	45,771
Deferred income taxes	**40,264**	31,397
Total current assets	**1,838,946**	1,629,363
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $2,459,022 in 2005 and $2,933,214 in 2004	**4,374,229**	3,685,594
Goodwill, net	**44,206**	43,582
Deferred charges and other assets	**111,130**	99,704
Total assets	**$6,368,511**	5,458,243
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long-term debt	**$ 4,490**	50,727
Accounts payable	**987,236**	709,378
Income taxes	**105,884**	241,935
Other taxes payable	**113,743**	147,459
Other accrued liabilities	**75,655**	55,492
Total current liabilities	**1,287,008**	1,204,991
Notes payable	**597,926**	597,735
Nonrecourse debt of a subsidiary	**11,648**	15,620
Deferred income taxes	**614,091**	577,043
Asset retirement obligations	**176,823**	201,932
Accrued major repair costs	**55,350**	44,246
Deferred credits and other liabilities	**164,675**	167,520
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, 2005 and 200,000,000 shares at December 31, 2004, issued 186,828,618 shares at December 31, 2005 and 94,613,379 shares at December 31, 2004	**186,829**	94,613
Capital in excess of par value	**437,963**	511,045
Retained earnings	**2,744,274**	1,981,020
Accumulated other comprehensive income	**131,324**	134,509
Unamortized restricted stock awards	**(16,410)**	(4,738)
Treasury stock	**(22,990)**	(67,293)
Total stockholders' equity	**3,460,990**	2,649,156
Total liabilities and stockholders' equity	**$6,368,511**	5,458,243

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(Thousands of dollars)*	2005	2004*	2003*
Operating Activities			
Net income	**$ 846,452**	701,315	294,197
Income from discontinued operations	**(8,549)**	(204,920)	(22,780)
Cumulative effect of change in accounting principle	**—**	—	6,993
Income from continuing operations	**837,903**	496,395	278,410
Adjustments to reconcile income from continuing operations to net cash provided by operating activities			
Depreciation, depletion and amortization	**396,875**	321,446	258,857
Impairment of long-lived assets	**—**	—	8,314
Provisions for major repairs	**35,020**	30,208	28,514
Expenditures for major repairs and asset retirements	**(31,919)**	(18,587)	(66,096)
Dry hole costs	**125,992**	110,866	60,674
Amortization of undeveloped leases	**22,819**	16,415	14,720
Accretion of asset retirement obligations	**9,704**	10,017	9,734
Deferred and noncurrent income tax charges	**40,755**	106,159	4,237
Pretax gains from disposition of assets	**(175,140)**	(69,594)	(61,524)
Net increase in noncash operating working capital	**(49,413)**	(20,053)	(37,285)
Other operating activities – net	**4,117**	51,785	2,572
Net cash provided by continuing operations	**1,216,713**	1,035,057	501,127
Net cash provided by discontinued operations	**8,549**	61,961	151,151
Net cash provided by operating activities	**1,225,262**	1,097,018	652,278
Investing Activities			
Property additions and dry hole costs	**(1,246,242)**	(938,449)	(868,870)
Proceeds from sale of property, plant and equipment	**172,653**	60,404	188,620
Proceeds from maturity of investment securities	**17,892**	—	—
Purchase of investment securities	**—**	(17,892)	—
Other investing activities – net	**(9,943)**	(840)	1,309
Investing activities of discontinued operations			
Sales proceeds	**—**	582,973	—
Other	**—**	(9,730)	(68,906)
Net cash required by investing activities	**(1,065,640)**	(323,534)	(747,847)
Financing Activities			
Additions to notes payable	**—**	—	309,500
Reductions of notes payable	**(46,386)**	(454,178)	(34,912)
Additions to nonrecourse debt of a subsidiary	**—**	30	188
Reductions of nonrecourse debt of a subsidiary	**(4,193)**	(40,829)	(41,844)
Proceeds from exercise of stock options and employee stock purchase plans	**26,513**	3,156	3,598
Cash dividends paid	**(83,198)**	(78,205)	(73,464)
Other financing activities – net	**(1,053)**	—	(1,533)
Net cash provided (required) by financing activities	**(108,317)**	(570,026)	161,533
Effect of exchange rate changes on cash and cash equivalents	**(1,497)**	79,642	21,504
Net increase in cash and cash equivalents	**49,808**	283,100	87,468
Cash and cash equivalents at January 1	**535,525**	252,425	164,957
Cash and cash equivalents at December 31	**$ 585,333**	535,525	252,425

* Revised to reconcile net cash provided by operating activities to net income. Amounts presented in 2004 and 2003 for Net cash provided by operating activities, Net cash required by investing activities and Net cash provided (required) by financing activities are unchanged by this revision.

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

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

Years Ended December 31 *(Thousands of dollars)*	2005	2004	2003
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	**—**	—	—
Common Stock – par $1.00, authorized 450,000,000 shares at December 31, 2005 and 200,000,000 shares at December 31, 2004 and 2003, issued 186,828,618 shares at December 31, 2005 and 94,613,379 shares at December 31, 2004 and 2003			
Balance at beginning of year	**$ 94,613**	94,613	94,613
Two-for-one stock split effective June 3, 2005	**92,216**	—	—
Balance at end of year	**186,829**	94,613	94,613
Capital in Excess of Par Value			
Balance at beginning of year	**511,045**	504,809	504,983
Exercise of stock options, including income tax benefits	**1,582**	738	729
Restricted stock transactions and other	**16,407**	4,610	(1,472)
Sale of stock under employee stock purchase plans	**1,145**	888	569
Two-for-one stock split effective June 3, 2005	**(92,216)**	—	—
Balance at end of year	**437,963**	511,045	504,809
Retained Earnings			
Balance at beginning of year	**1,981,020**	1,357,910	1,137,177
Net income for the year	**846,452**	701,315	294,197
Cash dividends – $.45 per share in 2005, $.425 per share in 2004 and $.40 per share in 2003	**(83,198)**	(78,205)	(73,464)
Balance at end of year	**2,744,274**	1,981,020	1,357,910
Accumulated Other Comprehensive Income (Loss)			
Balance at beginning of year	**134,509**	65,246	(66,790)
Foreign currency translation gains, net of income taxes	**18,060**	79,073	145,573
Cash flow hedging gains (losses), net of income taxes	**(18,041)**	(4,876)	17,912
Minimum pension liability adjustment, net of income taxes	**(3,204)**	(4,934)	(31,449)
Balance at end of year	**131,324**	134,509	65,246
Unamortized Restricted Stock Awards			
Balance at beginning of year	**(4,738)**	—	—
Stock awards	**(16,344)**	(4,756)	—
Amortization, forfeitures and changes in price of Common Stock	**4,672**	18	—
Balance at end of year	**(16,410)**	(4,738)	—
Treasury Stock			
Balance at beginning of year	**(67,293)**	(71,695)	(76,430)
Exercise of stock options	**38,790**	1,568	2,261
Sale of stock under employee stock purchase plans	**1,182**	617	799
Awarded restricted stock, net of forfeitures	**4,331**	2,217	1,675
Balance at end of year – 881,940 shares of Common Stock in 2005, 2,578,002 shares in 2004 and 2,742,781 shares in 2003	**(22,990)**	(67,293)	(71,695)
Total Stockholders' Equity	**$3,460,990**	2,649,156	1,950,883

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)***	**2005**	**2004**	**2003**
Net income	**$846,452**	701,315	294,197
Other comprehensive income (loss), net of tax			
Cash flow hedges			
Net derivative gains (losses)	**(15,670)**	8,022	(27,702)
Reclassification to income	**(2,371)**	(12,898)	45,614
Total cash flow hedges	**(18,041)**	(4,876)	17,912
Net gain from foreign currency translation	**18,060**	79,073	145,573
Minimum pension liability adjustment	**(3,204)**	(4,934)	(31,449)
Other comprehensive income (loss)	**(3,185)**	69,263	132,036
Comprehensive Income	**$843,267**	770,578	426,233

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 has an interest in a refinery in the United Kingdom. Murphy markets petroleum products under various brand names and to unbranded wholesale customers in North America and the United Kingdom.

PRINCIPLES OF CONSOLIDATION – The consolidated financial statements include the accounts of Murphy Oil Corporation and all majority-owned subsidiaries. Undivided interests in oil and gas joint ventures and certain other assets 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. 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, 2005 and 2004, 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 its 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. In certain cases, a determination of whether a drilled exploration 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 Position 19-1, Accounting for Suspended Well Costs, which became effective in April 2005, the Company capitalizes 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 are charged to expense as incurred. Development costs, including unsuccessful development wells, are capitalized.

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 evaluated asset are less than its carrying value.

As described in Note G, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations, on January 1, 2003. Under SFAS No. 143, estimated asset retirement costs are generally recognized when the asset is placed in service. Asset retirement costs are estimated by the Company's engineers using existing regulatory requirements and anticipated future inflation rates. Actual costs of asset retirements such as dismantling oil and gas production facilities and site restoration are charged against the related liability.

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. As more fully described on page F-32 of this Form 10-K report, proved reserves are estimated by the Company's engineers and are subject to future revisions based on availability of additional information. Asset retirement costs are amortized over proved reserves using the units of production method. Refineries and certain marketing facilities are depreciated primarily using the composite straight-line method with depreciable lives ranging from 16 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.

Full plant turnarounds for major processing units are scheduled at 4 1/2 year intervals at the Meraux, Louisiana refinery and five year intervals at the Superior, Wisconsin refinery. Turnarounds at the Milford Haven, Wales refinery are scheduled on a four year cycle. 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 occur during the interim period and will vary depending on operating requirements and events. Murphy accrues in advance for estimated costs of these turnarounds by recording monthly expense provisions. Future major repair costs are estimated by the Company's engineers. Actual costs incurred are charged against the accrued liability. Once the turnaround is completed and actual costs are reasonably known, variances between accrued and actual costs are recorded in Operating Expenses in the income statement in the current period. All other maintenance and repairs are expensed. 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 – The excess of the purchase price over the fair value of net assets acquired with the purchase of Beau Canada Exploration Ltd. (Beau Canada) in 2000 was recorded as goodwill. All goodwill recorded at December 31, 2005 and 2004 arose from the purchase of Beau Canada by the Company's wholly owned Canadian subsidiary. 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 carrying amount of goodwill at December 31, 2005 and 2004 was $44,206,000 and $43,582,000, respectively. The change in the carrying amount of goodwill during 2005 was primarily 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, 2005. 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.

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 in the Consolidated Statement of Income. Gains or losses from translating foreign functional currency into U.S. dollars are included in Accumulated Other Comprehensive Income on the Consolidated Balance Sheet.

DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES – The Company accounts for derivative instruments and hedging activity under SFAS No. 133, as amended by SFAS No. 138 and No. 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 hedged 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 potentially dilutive Common shares. Per share amounts for 2004 and 2003 have been restated to reflect the Company's two-for-one stock split effective June 3, 2005.

STOCK OPTIONS – Through 2005, the Company accounted for stock options using the intrinsic-value based method of accounting as prescribed by Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees and related interpretations. Under APB 25, the Company accrued costs of restricted stock and any stock option 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 have been equal to or greater than the fair market value of the Company's stock on the date of grant. As more fully described in Note B, SFAS No. 123 (revised 2004), Share-Based Payment, will require the Company to expense the fair value of stock-based compensation, including stock options, beginning on January 1, 2006.

Had the Company recorded compensation expense for stock options as prescribed by the previously issued SFAS No. 123, Accounting for Stock-Based Compensation, net income and earnings per share would be the pro forma amounts shown in the following table.

(Thousands of dollars except per share data)	**2005**	**2004**	**2003**
Net income – As reported	**$846,452**	701,315	294,197
Restricted stock compensation expense included in income, net of tax	**5,829**	1,353	197
Total stock-based compensation expense using fair value method for all awards, net of tax	**(10,309)**	(6,199)	(5,442)
Net income – Pro forma	**$841,972**	696,469	288,952
Net income per share – As reported, basic	**$ 4.59**	3.81	1.60
Pro forma, basic	**4.57**	3.78	1.57
As reported, diluted	**4.51**	3.75	1.59
Pro forma, diluted	**4.48**	3.72	1.55

The pro forma net income calculations reflect the following fair values of stock options granted in 2005, 2004 and 2003; fair values of options have been estimated using the Black-Scholes pricing model and the weighted-average assumptions as shown.

	2005	**2004**	**2003**
Fair value per option at grant date	**$ 11.79***	7.46*	$ 5.16*
Assumptions			
Dividend yield	**1.25%**	1.86%	2.12%
Expected volatility	**26.00%**	27.81%	28.77%
Risk-free interest rate	**3.74%**	3.24%	3.01%
Expected life	**5 yrs.**	5 yrs.	5 yrs.

* Fair values have been adjusted to reflect the two-for-one stock split effective June 3, 2005.

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

Note B – New Accounting Principles and Recent Accounting Pronouncements

The Financial Accounting Standards Board (FASB) has issued SFAS No. 123 (revised 2004), Share Based Payment, which replaces SFAS No. 123, Accounting for Stock-Based Compensation, and supersedes APB Opinion No. 25, Accounting for Stock Issued to Employees. SFAS No. 123 (revised 2004) 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 adoption of this statement will increase compensation expense by including a cost in future periods for the Company's stock options and Employee Stock Purchase Plan. The statement will be effective for the Company beginning January 1, 2006. The Company provides pro forma disclosures in Note A as if SFAS No. 123 was currently being applied. The Company expects to use the modified prospective transition method upon adoption of SFAS 123 (revised). Stock option awards are expected to qualify for accounting as equity awards. The adoption of this statement will increase compensation expense in the consolidated statement of income beginning in 2006 by including cost for the Company's stock options and Employee Stock Purchase Plan. The Company has preliminarily estimated this incremental expense to be $10 million in 2006.

The Emerging Issues Task Force (EITF) of the FASB has issued EITF 03-13, Applying the Conditions in Paragraph 42 of SFAS No. 144 in Determining Whether to Report Discontinued Operations. The EITF generally believes that current practice with respect to applying the criteria in paragraph 42 of SFAS No. 144 has not been applied consistently and has not resulted in broadening the reporting of asset dispositions as discontinued operations. EITF 03-13 contains further guidance for evaluating the cash flows of the component sold and what constitutes significant continuing involvement. In certain industries, EITF 03-13 may lead to more asset disposals being reported as discontinued operations in future periods. However, in the oil and gas industry, it may cause more asset disposals to continue to be classified as continuing operations due to clarification of what constitutes continuing involvement. This standard was adopted by the Company for all asset disposal transactions occurring after January 1, 2005.

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 in 2005. The Company recorded a tax benefit of $3,500,000 in 2005 related to the Act.

The FASB issued SFAS No. 153, Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29, in December 2004. This statement addressed the measurement of exchanges of nonmonetary assets and eliminated the exception from fair value measurement for nonmonetary exchanges of similar productive assets and replaced it with an exception for exchanges that do not have commercial substance. SFAS No. 153 was adopted by the Company on a prospective basis for nonmonetary asset exchanges occurring after June 30, 2005. The adoption of this statement did not have a significant impact on the Company's results of operations in 2005.

In March 2005, the FASB issued FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations, an interpretation of SFAS No. 143. This interpretation clarifies the term conditional asset retirement obligation as used in SFAS No. 143 and when a company would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. This interpretation was adopted by the Company during the fourth quarter 2005 and it had no impact on the Company's results of operations for 2005.

SFAS No. 151, Inventory Costs, was issued by the FASB in November 2004. This statement amends Accounting Research Bulletin No. 43, to clarify that abnormal amounts of idle facility expense, freight, handling costs and wasted materials should be recognized as current-period charges, and it also requires that allocation of fixed production overheads be based on the normal capacity of the related production facilities. The provisions of this statement will be effective on a prospective basis beginning January 1, 2006, and the Company does not expect the adoption of this statement to have a significant impact on its results of operations.

In March 2005, the EITF decided in Issue 04-6, Accounting for Stripping Costs Incurred during Production in the Mining Industry, 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 operations at Syncrude may be affected by this ruling. The EITF consensus is effective for the Company as of January 1, 2006 and any adjustment required upon adoption will be recorded as the cumulative effect of a change in accounting principle. The Company does not currently expect the adoption of this consensus to have a significant impact on its financial statements.

In September 2005, the EITF decided in Issue 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty, that two or more exchange transactions involving inventory with the same counterparty that are entered into in contemplation of one another should be combined for purposes of evaluating the effect of APB Opinion 29, Accounting for Nonmonetary Transactions. Additionally, the EITF decided that a nonmonetary exchange where an entity transfers finished goods inventory in exchange for the receipt of raw materials or work-in-progress inventory within the same line of business should generally be recognized by the entity at fair value. This consensus will be applied to new arrangements entered into beginning April 1, 2006, and to all inventory transactions that are completed after December 15, 2006 for arrangements entered into prior to March 15, 2006. The Company does not expect the adoption of this consensus to have a significant impact on its financial statements.

Note C – Discontinued Operations

The Company sold most of its western Canadian conventional oil and gas assets (sale properties) in the second quarter of 2004 for net proceeds of $582,973,000. The Company recorded a gain of $171,095,000, net of $23,486,000 in income taxes, 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. The operating results for the sale properties and the gain on sale have been reported as discontinued operations for all periods presented. The Company primarily utilized the proceeds of the sale to repay debt under revolving credit agreements. At the time of sale, the sale properties produced about 20,000 barrels of oil equivalent per day and had total proved reserves of approximately 43 million barrels equivalent from heavy oil, light oil, and natural gas properties.

The major assets and liabilities associated with the sale properties at the time of the sale were as follows:

(Thousands of dollars)	
Inventory	$ 1,741
Prepaid expense	907
Property, plant and equipment, net of accumulated depreciation, depletion and amortization	407,982
Goodwill, net	23,091
Other noncurrent assets	4,214
Assets sold	$ 437,935
Deferred income taxes	$ 25,092
Asset retirement obligations	49,543
Liabilities associated with assets sold	$ 74,635

The following table reflects the results of operations from the properties disposed of including gains on sale.

	Year Ended December 31,		
(Thousands of dollars)	**2005**	**2004**	**2003**
Revenues, including a pretax gain on sale of assets of $194,581 in 2004	**$ —**	274,568	207,387
Income before income tax expense	**—**	244,676	44,962
Income tax expense (benefit)	**(8,549)**	39,756	22,182

Note D – Property, Plant and Equipment

	December 31, 2005		December 31, 2004	
(Thousands of dollars)	**Cost**	**Net**	**Cost**	**Net**
Exploration and production[1]	**$ 4,799,064**	**3,195,177**[2]	4,773,328	2,634,962[2]
Refining	**1,176,421**	**546,610**	1,165,494	565,138
Marketing	**776,444**	**576,798**	632,255	462,298
Corporate and other	**81,322**	**55,644**	47,731	23,196
	$ 6,833,251	**4,374,229**	6,618,808	3,685,594

1 Includes mineral rights as follows:	**$ 193,065**	**129,873**	163,725	117,266

2 Includes $36,138 in 2005 and $21,527 in 2004 related to administrative assets and support equipment.

In the Consolidated Statement of Income for 2003, the Company recorded noncash charges of $8,314,000 for impairment of certain properties. After related income tax benefits, these write-downs reduced net income by $5,404,000 in 2003. The charge included $5,314,000 to write-down the cost of a refined product terminal to be closed and certain components of the Meraux refinery that were rendered obsolete upon completion of the refinery upgrade, and $3,000,000 to write-down the cost of a natural gas field in the Gulf of Mexico due to downward revisions in reserves caused by poor well performance. The carrying value of the natural gas field was reduced to its fair value based on projected future discounted net cash flows using the Company's estimate of future commodity prices.

During the three years ended December 31, 2005, the Company sold certain oil and gas properties and other assets and recorded before tax gains of $175,140,000 in 2005, $69,594,000 in 2004 and $61,524,000 in 2003. The primary assets sold in 2005 were mature oil and gas properties on the continental shelf of the Gulf of Mexico. In 2004, the Company sold the "T" Block field in the U.K. North Sea and in 2003 it sold the Ninian and Columba fields in the U.K. North Sea.

The FASB has issued FSP 19-1 to provide guidance on the accounting for exploratory well costs and to amend SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies. 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, 2005, 2004 and 2003, the Company had total capitalized drilling costs pending the determination of proved reserves of $275,256,000, $106,105,000 and $158,034,000, respectively. The following table reflects the net changes in capitalized exploratory well costs during the three-year period ended December 31, 2005.

(Thousands of dollars)	2005	2004	2003
Beginning balance at January 1	**$ 106,105**	158,034	72,556
Additions to capitalized exploratory well costs pending the determination of proved reserves	**169,151**	94,048	85,478
Reclassifications to proved properties based on the determination of proved reserves	**—**	(125,211)	—
Capitalized exploratory well costs charged to expense or sold	**—**	(20,766)	—
Ending balance at December 31	**$ 275,256**	106,105	158,034

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)	2005	2004	2003
Exploratory well costs capitalized for one year or less	**$ 172,596**	93,956	82,262
Exploratory well costs capitalized for more than one year	**102,660**	12,149	75,772
Balance at December 31	**$ 275,256**	106,105	158,034
Number of projects with exploratory well costs that have been capitalized for more than one year	**8**	1	7

Of the $102,660,000 of exploratory well costs capitalized more than one year, $23,181,000 is in the U.S. and $79,479,000 is in Malaysia. For the U.S. amounts, further drilling is ongoing or planned. In Malaysia, plans call for further drilling associated with suspended well costs of $25,038,000 and development studies are in various stages of completion for suspended well costs of $54,441,000.

Note E – Financing Arrangements

At December 31, 2005, the Company had an unused $1 billion committed credit facility with a major banking consortium that matures in June 2010. Borrowings under this facility bear interest at prime or varying cost of fund options. Facility fees are due at varying rates on the commitment. The Company also had uncommitted lines of credit with banks at December 31, 2005 totaling an equivalent US $774 million for a combination of U.S. dollar and Canadian dollar borrowings. 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 million in debt and/or equity securities.

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Note F – Long-term Debt

(Thousands of dollars)	December 31 2005	2004
Notes payable		
6.375% notes, due 2012, net of unamortized discount of $728 at December 31, 2005	**$349,272**	349,157
7.05% notes, due 2029, net of unamortized discount of $2,171 at December 31, 2005	**247,829**	247,737
6.23% structured loan	**—**	46,277
Other, 6% to 8%, due 2006-2021	**840**	956
Total notes payable	**597,941**	644,127
Nonrecourse debt of a subsidiary		
Loans payable to Canadian government, interest free, payable in Canadian dollars, due 2006-2009	**16,123**	19,955
Total debt including current maturities	**614,064**	664,082
Current maturities	**(4,490)**	(50,727)
Total long-term debt	**$609,574**	613,355

Maturities for the four years after 2006 are: $4,482,000 in 2007, $4,481,000 in 2008, $2,707,000 in 2009 and $1,000 in 2010.

With the support of a major bank consortium, the 6.23% structured loan was borrowed by a Canadian subsidiary in December 2000 to replace temporary financing of the Beau Canada acquisition. The loan was repaid in December 2005 in accordance with its original terms.

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

Note G – Asset Retirement Obligations

On January 1, 2003, the Company adopted 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 asset retirement obligation (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. 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 accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. 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. The estimation of the future asset retirement obligation 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. Upon adoption of SFAS No. 143, the Company recorded a charge of $6,993,000, net of $1,400,000 in income taxes, as the cumulative effect of a change in accounting principle.

The majority of the ARO recognized by the Company at December 31, 2005 and 2004 relates 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)	2005	2004
Balance at beginning of year	**$201,932**	252,397
Accretion expense	**9,704**	11,226
Liabilities incurred	**13,438**	20,340
Revision of previous estimates	**6,936**	2,602
Liabilities settled	**(56,066)**	(87,453)
Changes due to translation of foreign currencies	**879**	2,820
Balance at end of year	**$176,823**	201,932

Accretion expense of $1,209,000 included in the above table for 2004 was included in discontinued operations. Liabilities settled in 2005 and 2004 included approximately $47,554,000 and $76,932,000, respectively, for reductions of ARO associated with the sales of oil and gas producing properties.

Note H – Income Taxes

The components of income from continuing operations before income taxes for each of the three years ended December 31, 2005 and income tax expense (benefit) attributable thereto were as follows.

(Thousands of dollars)	2005	2004	2003
Income (loss) from continuing operations before income taxes			
United States	**$ 628,691**	244,758	(50,296)
Foreign	**743,368**	560,178	424,501
	$1,372,059	804,936	374,205
Income tax expense (benefit) from continuing operations			
Federal – Current	**$ 165,019**	22,446	(5,321)
Deferred	**43,693**	78,446	(11,911)
Noncurrent	—	(1,339)	(18,217)
	208,712	99,553	(35,449)
State	**10,229**	2,154	84
Foreign – Current	**319,976**	194,405	96,795
Deferred*	**(5,333)**	13,759	24,715
Noncurrent	**572**	(1,330)	9,650
	315,215	206,834	131,160
Total	**$ 534,156**	308,541	95,795

* Includes benefits of $4,923 in 2004 and $10,101 in 2003 for enacted reductions in federal and provincial tax rates in Canada.

Income tax benefits attributable to employee stock option transactions of $15,567,000 in 2005, $553,000 in 2004 and $467,000 in 2003 were included in Capital in Excess of Par Value in the Consolidated Balance Sheets. Income tax benefits of $7,795,000 in 2005, $2,712,000 in 2004 and $11,549,000 in 2003 relating to derivatives were included in Accumulated Other Comprehensive Income (AOCI).

Total income tax expense in 2005, 2004 and 2003, including taxes associated with discontinued operations and the cumulative effect of a change in accounting principle, was $525,607,000, $348,297,000, and $116,577,000, respectively.

Noncurrent taxes, classified in the Consolidated Balance Sheets as a component of Deferred Credits and Other Liabilities, relate primarily to matters not resolved with various taxing authorities.

The following table reconciles income taxes based on the U.S. statutory tax rate to the Company’s income tax expense from continuing operations and before cumulative effect of accounting change.

(Thousands of dollars)	2005	2004	2003
Income tax expense based on the U.S. statutory tax rate	**$480,221**	281,727	130,971
Foreign income subject to foreign taxes at a rate different than the U.S. statutory rate	**56,358**	23,002	9,865
Canadian withholding tax and federal tax on dividend	**8,520**	45,863	—
State income taxes, net of federal benefit	**6,649**	1,400	54
Settlement of U.S. and foreign taxes	**(21,849)**	(5,545)	(20,146)
Changes in foreign tax rates	**—**	(4,923)	(10,101)
Recognition of deferred income tax benefit related to exploration and other expenses in Malaysia	**—**	(31,858)	(11,410)
Other, net	**4,257**	(1,125)	(3,438)
Total	**$534,156**	308,541	95,795

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2005 and 2004 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	2005	2004
Deferred tax assets		
Property and leasehold costs	**$ 151,808**	118,179
Liabilities for dismantlements and major repairs	**82,765**	88,580
Postretirement and other employee benefits	**61,325**	58,770
Foreign tax credit carryforwards	**39,869**	22,625
Other deferred tax assets	**70,305**	72,057
Total gross deferred tax assets	**406,072**	360,211
Less valuation allowance	**(151,057)**	(83,962)
Net deferred tax assets*	**255,015**	276,249
Deferred tax liabilities		
Property, plant and equipment	**(73,509)**	(82,048)
Accumulated depreciation, depletion and amortization	**(541,564)**	(521,311)
Foreign currency translation gains	**(97,726)**	(91,019)
Other deferred tax liabilities	**(87,716)**	(96,740)
Total gross deferred tax liabilities	**(800,515)**	(791,118)
Net deferred tax liabilities	**$(545,500)**	(514,869)

* Includes deferred tax assets in Malaysia of $28,314,000 and $30,777,000 as of December 31, 2005 and 2004, respectively, that are reported in Deferred Charges and Other Assets in the Consolidated Balance Sheet.

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, and in the judgment of management, 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 and $11,410,000 in 2003 to recognize anticipated future tax benefits on exploration and other expenses related to Blocks K, SK 309 and SK 311 in Malaysia. The valuation allowance increased $67,095,000 in 2005, 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 and 2004, the Company recorded income tax expense of $8,520,000 and $45,863,000, respectively, related to repatriation of U.K. and Canadian earnings to the U.S. The most significant portion of the expense in both years 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 certain international subsidiaries because such earnings are considered permanently invested in foreign countries. As of December 31, 2005, undistributed earnings of international subsidiaries considered permanently invested were approximately $922,000,000. The unrecognized deferred tax liability is dependent of many factors including withholding taxes under current tax treaties and foreign tax credits and is estimated to be $46,100,000. 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, 2004 and 2003, the Company recorded benefits to income of $21,849,000, $5,545,000 and $20,146,000, respectively, from settlements of U.S. and foreign tax issues primarily related to prior years. Although the Company believes that adequate accruals have been made for unsettled issues, additional gains or losses could occur in future years from resolution of outstanding matters.

Note I – Incentive Plans

The Company's 1992 Stock Incentive Plan (1992 Plan) authorized the Executive Compensation Committee (the Committee) to make annual grants of the Company's Common Stock to executives and other key employees as follows: (1) stock options (nonqualified or incentive), (2) stock appreciation rights (SAR), and/or (3) restricted stock. Annual grants may not exceed 1% of shares outstanding at the end of the preceding year; allowed shares not granted may be granted in future years. In addition, shareholders approved the Stock Plan for Non-Employee Directors (2003 Director Plan) in 2003. This plan permits the issuance of restricted stock, stock options or a combination thereof to the Company's Directors. Through the end of 2005, the Company has used APB Opinion No. 25 to account for stock-based compensation, accruing costs of restricted stock and any stock options deemed to be variable in nature over the vesting/performance periods and adjusting these costs for changes in the fair market value of the Company's Common Stock. Compensation cost charged against income for stock-based plans was $15,181,000 in 2005, $3,122,000 in 2004 and $303,000 in 2003. Outstanding awards were not modified in the last three years.

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 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 1992 Plan, one-half of each grant may be exercised after two years and the remainder after three years. Under the 2003 Director Plan, one-third of each grant may be exercised after each of the first three years.

Changes in options outstanding during the last three years are presented in the following table. All shares and average exercise prices presented have been adjusted for the two-for-one stock split effective June 3, 2005.

	Number of Shares	Average Exercise Price
Outstanding at December 31, 2002	6,593,680	$15.54
Granted at FMV	1,691,000	21.54
Exercised	(173,000)	13.01
Forfeited	(42,560)	17.65
Outstanding at December 31, 2003	8,069,120	16.80
Granted at FMV	1,088,460	30.31
Exercised	(120,000)	13.82
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**
Exercisable at December 31, 2003	3,554,120	$13.66
Exercisable at December 31, 2004	5,372,120	15.03
Exercisable at December 31, 2005	**5,576,829**	**16.49**

Additional information about stock options outstanding at December 31, 2005 is shown below.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices per Option	No. of Options	Avg. Life in Years	Avg. Price	No. of Options	Avg. Price
$ 8.92 to $ 12.59	825,923	2.3	$10.73	825,923	$10.73
$13.85 to $ 16.37	2,451,781	4.3	15.02	2,451,781	15.02
$19.42 to $ 23.58	3,114,873	6.1	20.39	2,287,373	20.07
$30.29 to $ 45.23	2,022,060	7.2	37.21	11,752	30.67
	8,414,637	5.5	$21.92	5,576,829	$16.49

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.

RESTRICTED STOCK – Shares of restricted stock were granted under the Plan in certain years. Each grant will vest if the Company achieves specific financial objectives at the end of the performance period. Such performance periods have ranged from three to five years in length. Additional shares may be awarded if objectives are exceeded, but some or all shares may be forfeited if objectives are not met. During the performance period, a grantee receives dividends and may vote these shares, but shares are subject to transfer restrictions and are all or partially forfeited if a grantee terminates. The Company shall reimburse a grantee up to 50% of the award value for personal income tax liability on stock awarded. In 2003, additional shares related to the 1998 grant were awarded based on financial objectives achieved. Changes in restricted stock outstanding for each of the last three years are presented in the following table.

*(Number of shares)**	**2005**	**2004**	**2003**
Balance at beginning of year	**169,624**	—	—
Granted	**358,950**	170,900	128,168
Awarded	**—**	—	(128,168)
Forfeited	**(14,555)**	(1,276)	—
Balance at end of year	**514,019**	169,624	—

* All periods have been adjusted for the two-for-one stock split effective June 3, 2005.

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 objectives. Compensation expense of $17,634,000, $13,663,000 and $14,931,000 was recorded in 2005, 2004 and 2003, respectively, for these plans.

EMPLOYEE STOCK PURCHASE PLAN (ESPP) – The Company has an ESPP under which 600,000 shares of 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 a price equal to 90% of the fair value of the stock as of the first day of the quarter. The ESPP will terminate on the earlier of the date that employees have purchased all 600,000 shares or June 30, 2007. Employee stock purchases under the ESPP were 33,425 shares at an average price of $43.30 per share in 2005, 40,660 shares at $31.92 in 2004, and 60,256 shares at $22.40 in 2003. At December 31, 2005, 149,485 shares remained available for sale under the ESPP. Compensation costs related to the ESPP were immaterial. The number of shares and average prices shown above have been adjusted to reflect the two-for-one stock split effective June 3, 2005.

Note J – 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.

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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, 2005 and 2004 and a statement of the funded status as of December 31, 2005 and 2004.

(Thousands of dollars)	Pension Benefits 2005	Pension Benefits 2004	Postretirement Benefits 2005	Postretirement Benefits 2004
Change in benefit obligation				
Obligation at January 1	**$355,888**	330,577	**58,516**	65,774
Service cost	**9,099**	8,332	**1,906**	1,707
Interest cost	**20,478**	19,478	**3,749**	3,507
Plan amendments	**391**	—	**—**	—
Participant contributions	**45**	55	**797**	554
Actuarial loss (gain)	**26,607**	10,704	**10,642**	(8,227)
Exchange rate changes	**(7,173)**	6,227	**—**	—
Benefits paid	**(17,317)**	(16,665)	**(4,313)**	(3,975)
Special termination benefits	**—**	(2,820)	**—**	—
Other	**—**	—	**(73)**	(824)
Obligation at December 31	**388,018**	355,888	**71,224**	58,516
Change in plan assets				
Fair value of plan assets at January 1	**268,632**	261,182	**—**	—
Actual return on plan assets	**27,316**	16,170	**—**	—
Employer contributions	**26,433**	5,051	**3,516**	3,421
Participant contributions	**45**	55	**797**	554
Settlements	**—**	(2,693)	**—**	—
Exchange rate changes	**(4,485)**	5,532	**—**	—
Benefits paid	**(17,317)**	(16,665)	**(4,313)**	(3,975)
Other	**(240)**	—	**—**	—
Fair value of plan assets at December 31	**300,384**	268,632	**—**	—
Reconciliation of funded status				
Funded status at December 31	**(87,634)**	(87,256)	**(71,224)**	(58,516)
Unrecognized actuarial loss	**105,430**	95,025	**31,845**	22,798
Unrecognized transition asset	**(4,123)**	(4,635)	**—**	—
Unrecognized prior service cost	**4,860**	5,402	**(3,536)**	(3,813)
Net plan asset (liability) recognized	**$ 18,533**	8,536	**(42,915)**	(39,531)
Amounts recognized in the Consolidated Balance Sheets at December 31				
Prepaid benefit asset	**$ 8,451**	3,964	**—**	—
Accrued benefit liability	**(55,159)**	(57,045)	**(42,915)**	(39,531)
Intangible asset	**3,113**	4,421	**—**	—
Accumulated other comprehensive loss*	**62,128**	57,196	**—**	—
Net plan asset (liability) recognized	**$ 18,533**	8,536	**(42,915)**	(39,531)

* Before reduction for associated deferred taxes of $21,189 at December 31, 2005 and $19,461 at December 31, 2004.

A minimum pension liability adjustment was required for certain of the Company's plans. For these plans, accumulated benefit obligations exceeded the fair value of plan assets by $67,250,000. After reductions for amounts charged to intangible assets, net of associated deferred income taxes, charges that reduced accumulated other comprehensive income of $3,204,000, $4,934,000 and $31,449,000 were recorded in 2005, 2004 and 2003, respectively.

The Company's contributions shown in the table above for 2005 include $14,500,000 of voluntary amounts in excess of U.S. statutorily required contributions.

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.

(Thousands of dollars)	Projected Benefit Obligations 2005	Projected Benefit Obligations 2004	Accumulated Benefit Obligations 2005	Accumulated Benefit Obligations 2004	Fair Value of Plan Assets 2005	Fair Value of Plan Assets 2004
Funded qualified plans where PBO exceeds fair value of plan assets	**$ 341,125**	316,271	**299,582**	278,632	**252,632**	239,067
Unfunded nonqualified and directors' plans where PBO exceeds fair value of plan assets	**30,715**	25,578	**23,049**	20,562	**—**	—
Unfunded postretirement plans	**71,224**	58,516	**42,915**	39,531	**—**	—

The table that follows provides the components of net periodic benefit expense for each of the three years ended December 31, 2005.

(Thousands of dollars)	Pension Benefits 2005	Pension Benefits 2004	Pension Benefits 2003	Postretirement Benefits 2005	Postretirement Benefits 2004	Postretirement Benefits 2003
Service cost	**$ 9,099**	8,332	7,347	**1,906**	1,707	1,236
Interest cost	**20,478**	19,478	18,753	**3,749**	3,507	3,687
Expected return on plan assets	**(19,092)**	(18,620)	(17,275)	**—**	—	—
Amortization of prior service cost	**820**	785	764	**(277)**	(277)	(95)
Amortization of transitional asset	**(624)**	(636)	(2,052)	**—**	—	—
Recognized actuarial loss	**5,916**	4,554	3,664	**1,595**	1,347	1,334
	16,597	13,893	11,201	**6,973**	6,284	6,162
Curtailment expense	**—**	—	338	**—**	—	—
Settlement gain	**—**	(1,069)	—	**—**	—	—
Net periodic benefit expense	**$ 16,597**	12,824	11,539	**6,973**	6,284	6,162

Settlement gains in 2004 related to employee reductions associated with the sale of western Canadian conventional oil and gas properties. Curtailment expense in 2003 recorded unrecognized prior service costs related to the freezing of benefits under the Directors' retirement plan.

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

(Thousands of dollars)	Pension Benefits 2005	Pension Benefits 2004	Postretirement Benefits 2005	Postretirement Benefits 2004
Benefit obligation at December 31	**$92,500**	85,752	**—**	—
Fair value of plan assets at December 31	**85,300**	74,596	**—**	—
Net plan liability recognized	**5,289**	(408)	**—**	—
Net periodic benefit expense	**1,594**	613	**—**	—

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2005 and 2004 and net periodic benefit expense for the years 2005 and 2004.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits		Postretirement Benefits		Pension Benefits		Postretirement Benefits	
	December 31,		December 31,		Year		Year	
	2005	2004	2005	2004	2005	2004	2005	2004
Discount rate	**5.58%**	5.89%	**5.70%**	6.00%	**5.81%**	6.08%	**6.00%**	6.25%
Expected return on plan assets	**7.08%**	7.42%	**—**	—	**7.24%**	7.42%	**—**	—
Rate of compensation increase	**4.06%**	4.07%	**—**	—	**4.06%**	4.07%	**—**	—

Discount rates are adjusted as necessary, generally based on changes in AA-rated corporate bond rates. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Expected compensation increases are based on historical averages for the Company.

The weighted average asset allocation for the Company's benefit plans at the annual measurement dates of September 30, 2005 and 2004 are presented in the following table.

	September 30,	
	2005	2004
Equity securities	**56.3%**	53.5%
Debt securities	**38.6**	42.4
Cash	**5.1**	4.1
	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 60% for both equity and debt securities. The Company believes that a nearly balanced portfolio of equity and 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 expected return on plan assets was 7.08% in 2005 and the return was determined based on an assessment of actual long-term historical returns and expected future returns for a balanced portfolio similar to that maintained by the plans. The 7.08% expected return was based on an expected average future equity securities return of 9.06% and a debt securities return of 5.45% and is net of average expected investment expenses of .33%. Over the last 10 years, the return on funded retirement plan assets has averaged 8.41%.

The Company currently expects during 2006 to make contributions of $5,880,000 to its domestic defined benefit pension plans, $1,589,000 to its foreign defined pension plans and $3,556,000 to its domestic postretirement benefits plan.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid from the assets of the plans or by the Company:

(Thousands of dollars)	Pension Benefits	Postretirement Benefits
2006	$ 18,715	3,556
2007	19,279	3,778
2008	19,776	3,964
2009	20,356	4,234
2010	21,109	4,489
2011-2015	121,767	26,426

For purposes of measuring postretirement benefit obligations at December 31, 2005, the future annual rates of increase in the cost of health care were assumed to be 8.0% for 2006 decreasing each year to an ultimate rate of 5.0% in 2010 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, 2005	$ 994	(786)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 2005	10,883	(8,801)

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 for 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 accumulated postretirement benefit obligation was reduced by $6,715,000 at December 31, 2004, and its postretirement benefit expense was $1,410,000 and $1,000,000 lower during 2005 and 2004, 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 16,571 shares in 2005, 6,604 shares in 2004 and 864 shares in 2003. Amounts charged to expense for these U.S. and U.K. plans were $7,886,000 in 2005, $4,895,000 in 2004 and $5,377,000 in 2003.

Note K – Financial Instruments and Risk Management

DERIVATIVE INSTRUMENTS – Murphy makes limited use of derivative instruments to manage certain risks related to commodity prices, interest rates and foreign currency exchange rates. The use of derivative instruments for risk management is covered by operating policies and is closely monitored by the Company’s senior management. The Company does not hold any derivatives for speculative purposes and it does not use derivatives with leveraged or complex features. Derivative instruments are traded primarily with creditworthy major financial institutions or over national exchanges such as the New York Mercantile Exchange. 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.

- *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 has hedged the cash flow risk associated with the cost of a portion of the natural gas it will purchase in 2006 by entering into financial contracts known as natural gas swaps with a remaining notional volume as of December 31, 2005 of 720,000 MMBTU (1 MMBTU = 1 million British Thermal Units). Other similar contracts covered a portion of 2005 and 2004 purchases. Under the natural gas swaps, the Company pays a fixed rate averaging $3.35 per MMBTU and receives 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 is deferred in AOCI and is subsequently reclassified into Operating Expenses in the income statements in the periods in which the hedged natural gas fuel purchases occurred. During 2003, the Company determined that natural gas swap contract notional volumes with 2004 maturity dates exceeded forecasted 2004 natural gas purchases at its Meraux, Louisiana refinery while the ROSE unit was out of service. Accordingly, natural gas swap contracts with a notional volume of 3.4 million MMBTU at December 31, 2003 no longer qualified as a cash flow hedge. Therefore, 1.3 million MMBTU of these contracts were redesignated as a cash flow hedge of natural gas the Company expected to purchase at its Superior refinery during 2004, and the remaining 2.1 million MMBTU not qualifying as a hedge were marked to fair value through earnings during 2004. Gains of $6,700,000 were recognized in earnings in 2003 as a result of the contracts no longer qualifying as a cash flow hedge. During 2004 the Company entered into natural gas price swap agreements with notional volumes of 2.5 million MMBTU that effectively fixed the settlement price of the previously acquired contracts that matured in July through October 2004. The critical terms of all the 2004 contracts were nearly identical. Murphy was required to pay the average NYMEX price for the final three trading days of the month and receive an average natural gas price of $5.235 per MMBTU. For the three years ended December 31, 2005, the income effect from cash flow hedging ineffectiveness for these contracts was $1,021,000, $472,000 and $4,377,000, respectively, net of income taxes of $550,000, $254,000 and $2,357,000. During the years ended December 31, 2005 and 2004, the Company received approximately $7,635,000 and $21,798,000, 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 2005 and 2006 Canadian heavy oil production by entering into forward sale contracts covering a notional volume of approximately 2,000 barrels per day in 2005 and 4,000 barrels per day in 2006. In 2006, the Company will pay the average of the posted price at the Hardisty terminal in Canada for each month and receive a fixed price of $25.23 per barrel. In 2005, the Company paid the average Hardisty posted price and received $29.00 per barrel. In 2003, Murphy hedged the cash flow risk associated with the sales price for the crude oil it produced in the United States and a portion of the oil produced in Canada by entering into crude oil swap contracts. The 2003 swaps covered a notional volume of 22,000 barrels per day of light oil and required Murphy to pay the average of the closing settlement price on the NYMEX for the Nearby Light Crude Futures Contract for each month and receive an average price of $25.30 per barrel. Additionally, in 2003, there were heavy oil swaps with a notional volume of 10,000 barrels per day that required Murphy to pay the arithmetic average of the posted price at terminals at Kerrobert and Hardisty, Canada for each month and receive an average price of $16.74 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 light and heavy crude oil.

  The fair values of the effective portions of the crude oil sales price hedges and changes thereto were deferred in AOCI and subsequently reclassified into Sales and Other Operating Revenues in the income statement in the periods in which the hedged crude oil sales occurred. During 2005, 2004 and 2003, earnings were increased by $65,000, $225,000 and $1,507,000, respectively, for cash flow hedging ineffectiveness on crude oil sales price hedges. During 2005 and 2003 the Company paid approximately $5,254,000 and $66,950,000, respectively, for settlement of maturing crude oil sales swaps.

- *Natural Gas Sales Price Risks* – The sales price of natural gas produced by the Company is subject to commodity price risk. During the first ten months of 2004 Murphy had natural gas put options covering a combined United States natural gas sales volume averaging 25,000 MMBTU per day. The strike price provided the Company with a floor price of $4.00 per MMBTU and these contracts settled monthly through October 2004. During 2003 Murphy hedged the cash flow risk associated with the sales price for a portion of the natural gas it produced in the United States and Canada by entering into natural gas swap and collar contracts. The swaps covered a combined notional volume averaging 24,200 MMBTU equivalents per day and required Murphy to pay the average relevant index (NYMEX or AECO "C") price for each month and receive an average price of $3.76 per MMBTU equivalent. The natural gas collars were for a combined notional volume averaging 26,700 MMBTU equivalents per day and provided Murphy with an average floor price of $3.24 per MMBTU and an average ceiling price of $4.64 per MMBTU. Murphy has a risk management control system to monitor natural gas price risk attributable both to forecasted natural gas sales prices and to Murphy's hedging instruments. The control system involves using analytical techniques, including various correlations of natural gas sales prices to futures prices, to estimate the impact of changes in natural gas prices on Murphy's cash flows from the sale of natural gas.

  The fair values of the effective portions of the natural gas swaps collars and puts and changes thereto were deferred in AOCI and were subsequently reclassified into Sales and Other Operating Revenue in the income statement in the periods in which the hedged natural gas sales occurred. During 2004 and 2003, Murphy's earnings were not significantly affected by cash flow hedging ineffectiveness on natural gas sales price hedges. There were no settlement payments received in 2004 relating to the natural gas put options. During 2003, the Company paid $13,107,000 for settlement of natural gas swap and collar agreements.

Based on fair value of contracts as of December 31, 2005, the Company expects to reclassify approximately $13,459,000 in net after-tax losses from AOCI into earnings in 2006 as the forecasted transactions covered by hedging instruments actually occur. All forecasted transactions currently being hedged are expected to occur by December 2006.

FAIR VALUE – The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2005 and 2004. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties. The table excludes cash and cash equivalents, trade accounts receivable, trade accounts payable and accrued expenses, all of which had fair values approximating carrying amounts. The fair value of investment in marketable securities in 2004 was estimated based on quotes offered by major financial institutions. 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.

	2005		2004	
(Thousands of dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Financial assets (liabilities):				
Investment in marketable securities	$ —	—	17,892	17,892
Natural gas fuel swaps	**5,225**	**5,225**	6,099	6,099
Crude oil sales swaps	**(24,268)**	**(24,268)**	594	594
Current and long-term debt	**(614,064)**	**(664,231)**	(664,082)	(791,200)

The carrying amounts of crude oil swaps and natural gas swaps in the preceding table are included in the Consolidated Balance Sheets in Accounts Receivable or Other Accrued Liabilities. Current and long-term debts are included under Current Maturities of Long-Term Debt, Notes Payable and Nonrecourse Debt of a Subsidiary.

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

Note L – 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 M – 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, 2005. No difference existed between net income used in computing basic and diluted income per Common share for these years. There were no antidilutive options for the periods presented.

(Weighted-average shares outstanding)	2005	2004	2003
Basic method	**184,354,552**	183,972,642	183,629,642
Dilutive stock options	**3,534,826**	2,914,380	1,855,890
Diluted method	**187,889,378**	186,887,022	185,485,532

Note N – Other Financial Information

INVENTORIES – Inventories accounted for under the LIFO method totaled $157,255,000 and $139,489,000 at December 31, 2005 and 2004, respectively, and these amounts were $361,345,000 and $219,075,000 less than such inventories would have been valued using the FIFO method.

ACCUMULATED OTHER COMPREHENSIVE INCOME – At December 31, 2005 and 2004, the components of Accumulated Other Comprehensive Income were as follows.

(Thousands of dollars)	2005	2004
Foreign currency translation gain, net of tax	**$185,722**	167,662
Cash flow hedge (losses) gains, net of tax	**(13,459)**	4,582
Minimum pension liability, net of tax	**(40,939)**	(37,735)
Balance at end of year	**$131,324**	134,509

At December 31, 2005, components of the net foreign currency translation gain of $185,722,000 were gains of $43,805,000 for pounds sterling, $140,906,000 for Canadian dollars and $1,011,000 for other currencies. Foreign currency translation gains shown in the table are net of income taxes of $97,726,000 and $91,019,000 at year-end 2005 and 2004, respectively. Net gains (losses) from foreign currency transactions included in the Consolidated Statements of Income were $102,000 in 2005, $(26,613,000) in 2004 and $4,087,000 in 2003.

The effect of SFAS Nos. 133/138, Accounting for Derivative Instruments and Hedging Activities, decreased AOCI for the year ended December 31, 2005 by $18,041,000, net of $7,795,000 in income taxes, and income increased by $1,086,000 for the same period. For the year ended December 31, 2004, AOCI decreased by $4,876,000, net of $2,712,000 in income taxes, and income increased by $340,000. For the year ended December 31, 2003, AOCI increased by $17,912,000, net of $11,549,000 in income taxes, and income increased by $5,988,000.

CASH FLOW DISCLOSURES – Cash income taxes paid were $586,544,000, $184,950,000 and $86,750,000 in 2005, 2004 and 2003, respectively. Interest paid, net of amounts capitalized, was $6,095,000, $32,141,000 and $17,501,000 in 2005, 2004 and 2003, respectively.

Noncash operating working capital increased during each of the three years ended December 31, 2005 as follows.

(Thousands of dollars)	2005	2004	2003
Accounts receivable	**$(162,222)**	(252,732)	(41,419)
Inventories	**(19,110)**	(25,335)	(69,166)
Prepaid expenses	**12,532**	(992)	15,183
Deferred income tax assets	**(8,867)**	(10,457)	(1,825)
Accounts payable and accrued liabilities	**264,305**	252,720	60,380
Current income tax liabilities	**(136,051)**	16,743	(438)
Net increase in noncash operating working capital from continuing operations	**$ (49,413)**	(20,053)	(37,285)

Note O – Hurricane and Insurance Related Matters

In 2005, the Company recorded pretax expenses, net of anticipated insurance recoveries, of $66,770,000 associated with hurricanes that occurred in the United States. The components of these costs included $22,945,000 for incremental insurance expenses; $15,493,000 for uninsured losses within the Company's insurance deductibles and other incremental expenses incurred that are not covered by insurance policies; $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 for the temporarily idled Meraux, Louisiana, refinery. The Company anticipates that additional costs related to Hurricane Katrina will be recorded in future periods. The repair of flood and wind damages at the Meraux refinery has been estimated to cost $200,000,000. Because of certain limitations on insurance policies, the Company could have unrecoverable repair costs of $50,000,000 in the first half of 2006 related to the Meraux refinery repairs. In 2004 the Company reported pretax costs of $3,350,000 for uninsured losses within the Company's insurance deductibles. The costs are reported in Net Costs Associated with Hurricanes in the Consolidated Statements of Income. See Note Q for additional information regarding environmental and other contingencies relating to Hurricane Katrina. Total accounts receivable from insurers for hurricane-related matters was $77,293,000 at December 31, 2005.

The Company maintains insurance coverage related to losses of production and profits for occurrences such as storms, fires and other issues. During 2005, the Company received insurance proceeds of $11,258,000 related to loss of production in the Gulf of Mexico associated with Hurricane Ivan in 2004 and Hurricane Lili in 2002. During 2004, the Company received insurance proceeds of $8,300,000 for lost profits at the Meraux refinery due to the ROSE unit fire in 2003, and $2,000,000 related to loss of production in the Gulf of Mexico associated with Hurricane Lili in 2002. These amounts were recorded in Sales and Other Operating Revenues in the respective Consolidated Statement of Income. The Company expects to collect further insurance receipts for loss of production related to Hurricanes Katrina and Rita in future periods.

Note P – Commitments

The Company leases land, gasoline stations and other facilities under operating leases. During the next five years, expected future rental payments under operating leases are approximately $19,707,000 in 2006; $18,417,000 in 2007; $18,235,000 in 2008; $17,071,000 in 2009; and $15,981,000 in 2010. Rental expense for noncancellable operating leases, including contingent payments when applicable, was $33,379,000 in 2005, $27,943,000 in 2004, and $32,859,000 in 2003.

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 2019. The contract requires the payment of a base facility charge for use of the facility. Future required minimum annual payments for base facility charges are $5,471,000 in 2006; $6,828,000 in 2007; $7,101,000 in 2008; $7,385,000 in 2009; and $7,680,000 in 2010. Base facility charges and hydrogen costs incurred in the three-year period ended December 31, 2005 totaled $21,595,000, $27,141,000, and $1,128,000, respectively. As a result of the refinery being shut down for several months following Hurricane Katrina, the Company has 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 currently expects to complete repairs to its refinery and begin 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.

The Company has an Operating and Production Handling Agreement providing for processing and production handling services for hydrocarbon production from certain fields in the Gulf of Mexico. This agreement requires minimum annual payments for processing charges for the periods from 2006 through 2009. Under the agreement, the Company must make specified minimum payments quarterly. Future required minimum payments are $15,340,000 in 2006; $12,596,000 in 2007; $9,508,000 in 2008; and $13,272,000 in 2009. 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 in 2005 and 2004 were $24,297,000 and $23,430,000, respectively.

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 $2,006,000 in 2006 through 2010. 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 $2,521,000 in 2005, $2,390,000 in 2004 and $1,965,000 in 2003.

Commitments for capital expenditures were approximately $932,000,000 at December 31, 2005, including $57,000,000 for costs to develop deepwater Gulf of Mexico fields, $585,000,000 for field development and future work commitments in Malaysia, $69,000,000 for exploration drilling in the Republic of Congo and $73,000,000 for future work commitments on the Scotian Shelf offshore eastern Canada.

Note Q – Contingencies

The Company's operations and earnings have been and may be affected by various forms of governmental action both in the United States and throughout the world. Examples of such governmental action include, but are by no means limited to: tax increases and retroactive tax claims; 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 62 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. Environmental laws and regulations are described more fully in Management's Discussion and Analysis beginning on page 22 of this Form 10-K report.

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 flooding damage to a crude oil storage tank following Hurricane Katrina. Since then additional class action lawsuits have been filed in the same court against Murphy Oil USA, Inc. and/or Murphy Oil Corporation also seeking unspecified damages related to the crude oil release. The suits have been consolidated into a single action in the U.S. District Court for the Eastern District of Louisiana, which held a class certification hearing on January 12-13, 2006. The Court certified the class on January 30, 2006. The Company believes that insurance coverage exists for this release and it does not expect to incur significant costs associated with the class action lawsuits. Accordingly, the Company believes that the ultimate resolution of these class action lawsuits will not 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. 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.

In December 2000, two of the Company's Canadian subsidiaries, Murphy Oil Company Ltd. (MOCL) and Murphy Canada Exploration Company (MCEC) as plaintiffs filed an action in the Court of Queen's Bench of Alberta seeking a constructive trust over oil and gas leasehold rights to Crown lands in British Columbia. The suit alleges that the defendants, The Predator Corporation Ltd. and Predator Energies Partnership (collectively Predator) and Ricks Nova Scotia Co. (Ricks), acquired the lands after first inappropriately obtaining confidential and proprietary data belonging to the Company and its partner. In January 2001, Ricks, representing an undivided 75% interest in the lands in question, settled its portion of the litigation by conveying its interest to the Company and its partner at cost. In 2001, Predator, representing the remaining undivided 25% of the lands in question, filed a counterclaim against MOCL and MCEC and MOCL's President individually seeking compensatory damages of C$3.61 billion. In September 2004 the court summarily dismissed all claims against MOCL's president and all but C$356 million of the counterclaim against the Company. On February 28, 2006, the Court of Appeals ruled in favor of the Company and affirmed the dismissal order. The Company believes that the counterclaim is without merit, that the amount of damages sought is frivolous and the likelihood of a material loss to the Company is remote. It is anticipated that a trial concerning the 25% disputed interest and any remaining issues will commence in 2006. While no assurance can be given about the outcome, the Company does not believe that the ultimate resolution of this suit will have a material adverse effect on its net income, financial condition or liquidity in a future period. In the unlikely event that Predator were to prevail in its counterclaim in an amount approaching the damages sought, Murphy would incur a material expense in its consolidated statement of income, and would have a material effect on its financial condition and liquidity.

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, 2005, the Company had contingent liabilities of $8,519,000 under a financial guarantee described in the following paragraph and $50,212,000 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 2006 and 2021. 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 a Throughput and Deficiency agreement (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, 2005, 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 R – Common Stock Issued and Outstanding

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2005 is shown below.

(Number of shares outstanding)	2005	2004	2003
At beginning of year	**92,035,377**	91,870,598	91,689,454
Stock options exercised	**1,488,063**	60,000	86,500
Employee stock purchase and thrift plans	**45,344**	23,632	30,560
Restricted stock awards, net of forfeitures	**165,920**	84,812	64,084
Two-for-one stock split effective June 3, 2005	**92,215,239**	—	—
All other	**(3,265)**	(3,665)	—
At end of year	**185,946,678**	92,035,377	91,870,598

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. Per share amounts shown in the consolidated financial statements for all periods reflect the two-for-one stock split. Further information regarding the split is presented in the Consolidated Statement of Stockholders' Equity.

Note S – Business Segments

Murphy's reportable segments are organized into two major types of business activities, each subdivided into geographic areas of operations. The Company's exploration and production activity is subdivided into segments for the United States, Canada, the United Kingdom, Ecuador, Malaysia and all other countries; each of these segments derives revenues primarily from the sale of crude oil and natural gas. The refining and marketing segments in North America and the United Kingdom derive revenues mainly from the sale of petroleum products. The Company sells gasoline in the United States and Canada at retail stations built at Wal-Mart Supercenters. The total U.S. and Canadian refining and marketing business is considered by the Company to be an integrated operation, and therefore, considers it appropriate to combine these businesses into one North American segment. The Company's management evaluates segment performance based on income from operations, excluding interest income and interest expense. Intersegment transfers of crude oil, natural gas and petroleum products are at market prices and intersegment services are recorded at cost.

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

Excise taxes on petroleum products of $1,459,713,000, $1,477,873,000, and $1,336,600,000 for the years 2005, 2004 and 2003, respectively, that were collected by the Company and remitted to various government entities were excluded from revenues and costs and expenses.

Segment Information (Millions of dollars)	Exploration and Production U.S.	Canada	U.K.	Ecuador	Malaysia	Other	Total
Year ended December 31, 2005							
Segment income (loss) from continuing operations	**$ 385.5**	**308.2**	**79.9**	**38.1**	**(4.7)**	**(58.9)**	**748.1**
Revenues from external customers	**849.0**	**721.6**	**180.7**	**116.6**	**234.0**	**4.4**	**2,106.3**
Intersegment revenues	**—**	**59.7**	**—**	**—**	**—**	**—**	**59.7**
Interest income	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Interest expense, net of capitalization	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Income tax expense	**204.4**	**155.0**	**47.7**	**27.7**	**45.1**	**.7**	**480.6**
Significant noncash charges (credits)							
Depreciation, depletion, amortization	**87.2**	**134.2**	**25.0**	**23.5**	**48.9**	**.3**	**319.1**
Accretion of asset retirement obligations	**3.3**	**4.0**	**1.6**	**—**	**.2**	**.5**	**9.6**
Provisions for major repairs	**—**	**5.5**	**—**	**—**	**—**	**—**	**5.5**
Amortization of undeveloped leases	**18.2**	**3.1**	**—**	**—**	**—**	**1.5**	**22.8**
Deferred and noncurrent income taxes	**25.7**	**(30.7)**	**(4.0)**	**—**	**9.5**	**—**	**.5**
Additions to property, plant, equipment	**142.0**	**263.4**	**21.6**	**23.9**	**374.4**	**57.0**	**882.3**
Total assets at year-end	**896.4**	**1,552.1**	**194.6**	**134.4**	**844.7**	**77.5**	**3,699.7**
Year ended December 31, 2004							
Segment income (loss) from continuing operations	$ 159.5	232.2	87.1	6.6	38.3	(11.4)	512.3
Revenues from external customers	482.8	543.9	197.4	30.8	167.2	3.4	1,425.5
Intersegment revenues	—	62.8	—	—	—	—	62.8
Interest income	—	—	—	—	—	—	—
Interest expense, net of capitalization	—	—	—	—	—	—	—
Income tax expense	78.6	100.8	55.0	4.4	8.8	1.8	249.4
Significant noncash charges (credits)							
Depreciation, depletion, amortization	66.9	111.6	28.0	5.3	29.6	.1	241.5
Accretion of asset retirement obligations	3.7	3.3	2.3	—	.2	.4	9.9
Provisions for major repairs	—	6.2	—	—	—	—	6.2
Amortization of undeveloped leases	12.8	2.7	—	—	—	.9	16.4
Deferred and noncurrent income taxes	60.6	9.7	8.5	—	(18.5)	(14.5)	45.8
Additions to property, plant, equipment	144.3	320.7	3.0	12.5	197.5	13.3	691.3
Total assets at year-end	866.3	1,365.4	190.2	131.3	486.7	29.3	3,069.2
Year ended December 31, 2003							
Segment income (loss) from continuing operations	$ 23.3	166.2	95.3	16.7	10.7	(8.8)	303.4
Revenues from external customers	196.7	406.3	221.6	41.9	77.7	4.2	948.4
Intersegment revenues	—	50.0	—	—	—	—	50.0
Interest income	—	—	—	—	—	—	—
Interest expense, net of capitalization	—	—	—	—	—	—	—
Income tax expense (benefit)	13.2	59.9	59.8	.6	3.7	.7	137.9
Significant noncash charges (credits)							
Depreciation, depletion, amortization	36.7	103.1	32.6	7.5	18.5	.2	198.6
Impairment of long-lived assets	3.0	—	—	—	—	—	3.0
Accretion of asset retirement obligations	3.3	2.9	2.9	—	.3	.3	9.7
Provisions for major repairs	—	6.5	—	—	—	—	6.5
Amortization of undeveloped leases	11.5	3.1	.1	—	—	—	14.7
Deferred and noncurrent income taxes	13.4	(4.9)	24.8	—	(7.0)	2.2	28.5
Additions to property, plant, equipment	229.9	157.5	24.5	27.0	152.8	—	591.7
Total assets at year-end	742.6	1,527.1	211.4	105.5	284.0	17.9	2,888.5

Geographic Information (Millions of dollars)	Certain Long-Lived Assets at December 31 U.S.	Canada	U.K.	Ecuador	Malaysia	Other	Total
2005	**$1,725.3**	**1,425.2**	**327.6**	**93.9**	**734.6**	**76.1**	**4,382.7**
2004	1,638.2	1,260.4	277.0	90.6	406.5	21.5	3,694.2
2003	1,514.9	1,386.8	295.6	89.9	243.3	7.8	3,538.3

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Segment Information (Continued) *(Millions of dollars)*	Refining and Marketing			Corp. & Other	Consolidated
	North America	U.K.	Total		
Year ended December 31, 2005					
Segment income (loss) from continuing operations	**$ 85.5**	**39.8**	**125.3**	**(35.5)**	**837.9**
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)	**49.2**	**20.0**	**69.2**	**(15.6)**	**534.2**
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**
Provisions for major repairs	**20.7**	**8.7**	**29.4**	**.1**	**35.0**
Amortization of undeveloped leases	**—**	**—**	**—**	**—**	**22.8**
Deferred and noncurrent income taxes	**8.9**	**4.6**	**13.5**	**26.8**	**40.8**
Additions to property, plant, equipment	**123.3**	**79.1**	**202.4**	**35.5**	**1,120.2**
Total assets at year-end	**1,599.7**	**399.9**	**1,999.6**	**669.2**	**6,368.5**
Year ended December 31, 2004					
Segment income (loss) from continuing operations	$ 53.4	28.5	81.9	(97.8)	496.4
Revenues from external customers	6,264.9	678.3	6,943.2	(8.9)	8,359.8
Intersegment revenues	—	—	—	—	62.8
Interest income	—	—	—	17.7	17.7
Interest expense, net of capitalization	—	—	—	34.1	34.1
Income tax expense	37.4	14.4	51.8	7.3	308.5
Significant noncash charges (credits)					
Depreciation, depletion, amortization	66.7	10.6	77.3	2.6	321.4
Accretion of asset retirement obligations	.1	—	.1	—	10.0
Provisions for major repairs	20.0	3.9	23.9	.1	30.2
Amortization of undeveloped leases	—	—	—	—	16.4
Deferred and noncurrent income taxes	30.7	(1.5)	29.2	32.6	107.6
Additions to property, plant, equipment	123.7	11.0	134.7	1.5	827.5
Total assets at year-end	1,467.2	310.8	1,778.0	611.0	5,458.2
Year ended December 31, 2003					
Segment income (loss) from continuing operations	$ (21.2)	10.0	(11.2)	(13.8)	278.4
Revenues from external customers	3,722.4	483.8	4,206.2	10.0	5,164.6
Intersegment revenues	—	—	—	—	50.0
Interest income	—	—	—	4.4	4.4
Interest expense, net of capitalization	—	—	—	20.5	20.5
Income tax expense (benefit)	(11.9)	5.8	(6.1)	(36.0)	95.8
Significant noncash charges (credits)					
Depreciation, depletion, amortization	49.4	8.2	57.6	2.7	258.9
Impairment of long-lived assets	5.3	—	5.3	—	8.3
Accretion of asset retirement obligations	—	—	—	—	9.7
Provisions for major repairs	18.5	3.4	21.9	.1	28.5
Amortization of undeveloped leases	—	—	—	—	14.7
Deferred and noncurrent income taxes	(13.3)	(.6)	(13.9)	(10.4)	4.2
Additions to property, plant, equipment	205.8	9.6	215.4	1.1	808.2
Total assets at year-end	1,254.1	253.3	1,507.4	316.7	4,712.6

Geographic Information *(Millions of dollars)*	Revenues from External Customers for the Year						
	U.S.	U.K.	Canada	Ecuador	Malaysia	Other	Total
2005	**$9,661.9**	**1,100.3**	**759.7**	**116.6**	**234.0**	**4.6**	**11,877.1**
2004	6,713.7	872.1	572.6	30.8	167.2	3.4	8,359.8
2003	3,883.4	706.5	450.9	41.9	77.7	4.2	5,164.6

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

The following 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. Oil reserves associated with the participation contract in Ecuador totaled 16.5 million barrels at December 31, 2005. Oil reserves in Malaysia are associated with production sharing contracts for Blocks SK 309 and K. Malaysia reserves include oil to be received for both cost recovery and profit provisions under the contracts. Oil reserves associated with the production sharing contracts in Malaysia totaled 47.5 million barrels at December 31, 2005.

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

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. The average year-end 2005 crude oil prices were $53.38 per barrel for the United States, $52.42 for Canadian light, $23.44 for Canadian heavy, $57.32 for Canadian offshore, $57.72 for the United Kingdom, $36.90 for Ecuador and $46.25 for Malaysia. Average year-end 2005 natural gas prices were $10.33 per MCF for the United States, $8.56 for Canada and $5.25 for the United Kingdom.

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, 2005.

Schedule 1 – Estimated Net Proved Oil Reserves

(Millions of barrels)	United States	Canada*	United Kingdom	Ecuador	Malaysia	Total
Proved						
December 31, 2002	80.6	59.7	43.1	32.9	15.3	231.6
Revisions of previous estimates	(1.7)	8.0	.4	(.6)	.5	6.6
Extensions and discoveries	1.0	10.2	—	—	3.8	15.0
Production	(1.7)	(15.0)	(5.4)	(1.9)	(2.7)	(26.7)
Sales of properties	—	(2.9)	(9.8)	—	—	(12.7)
December 31, 2003	78.2	60.0	28.3	30.4	16.9	213.8
Revisions of previous estimates	(7.4)	(6.5)	.4	(10.3)	(1.1)	(24.9)
Purchases of properties	—	7.1	—	—	—	7.1
Extensions and discoveries	2.4	13.1	.6	—	42.6	58.7
Production	(7.1)	(12.8)	(4.0)	(2.8)	(4.4)	(31.1)
Sales of properties	(.1)	(19.7)	(1.0)	—	—	(20.8)
December 31, 2004	66.0	41.2	24.3	17.3	54.0	202.8
Revisions of previous estimates	**(6.4)**	**3.0**	**1.9**	**2.1**	**(1.5)**	**(.9)**
Improved recovery	—	**2.9**	—	—	—	**2.9**
Extensions and discoveries	**.1**	**12.0**	—	—	—	**12.1**
Production	**(9.4)**	**(12.9)**	**(2.9)**	**(2.9)**	**(5.0)**	**(33.1)**
Sales of properties	**(1.4)**	**(.4)**	—	—	—	**(1.8)**
December 31, 2005	**48.9**	**45.8**	**23.3**	**16.5**	**47.5**	**182.0**
Proved Developed						
December 31, 2002	5.2	47.1	36.2	19.0	—	107.5
December 31, 2003	23.9	47.7	24.4	17.7	11.8	125.5
December 31, 2004	31.3	32.5	19.8	7.9	12.4	103.9
December 31, 2005	**28.3**	**43.5**	**20.0**	**8.2**	**7.3**	**107.3**

* Includes net proved oil reserves related to discontinued operations of 20.8 million barrels at December 31, 2003 and 22.5 million barrels at December 31, 2002.

Schedule 2 – Estimated Net Proved Natural Gas Reserves

(Billions of cubic feet)	United States	Canada*	United Kingdom	Total
Proved				
December 31, 2002	268.5	225.9	30.8	525.2
Revisions of previous estimates	(4.5)	(8.6)	.1	(13.0)
Extensions and discoveries	14.7	16.8	—	31.5
Production	(30.0)	(45.1)	(3.5)	(78.6)
Sales of properties	—	(15.8)	—	(15.8)
December 31, 2003	248.7	173.2	27.4	449.3
Revisions of previous estimates	8.1	3.5	—	11.6
Extensions and discoveries	4.6	4.0	—	8.6
Production	(32.4)	(16.4)	(2.5)	(51.3)
Sales of properties	(8.5)	(140.7)	(.2)	(149.4)
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**
Proved Developed				
December 31, 2002	139.7	205.6	30.1	375.4
December 31, 2003	150.5	156.0	26.6	333.1
December 31, 2004	136.6	22.2	24.0	182.8
December 31, 2005	**75.2**	**24.2**	**26.0**	**125.4**

* Includes net proved natural gas reserves related to discontinued operations of 150.5 billion cubic feet at December 31, 2003 and 195.5 billion cubic feet at December 31, 2002.

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-38.

Synthetic Oil Proved Reserves
(Millionsof barrels)

December 31, 2002	136.2
December 31, 2003	136.8
December 31, 2004	138.0
December 31, 2005	**133.1**

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

(Millions of dollars)	United States	Canada[1,2]	United Kingdom	Ecuador	Malaysia	Other	Total
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[3]	**79.7**	**7.2**	**4.1**	**1.0**	**209.3**	**106.4**	**407.7**
Development costs[3]	**84.2**	**154.1**	**22.0**	**23.9**	**268.9**	**1.0**	**554.1**
Total costs incurred	**196.4**	**163.5**	**26.1**	**24.9**	**478.2**	**107.4**	**996.5**
Charged to expense							
Dry hole expense	**21.4**	**(1.0)**	**3.8**	**1.0**	**55.8**	**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**	**1.0**	**101.7**	**50.4**	**209.6**
Property additions	**$151.2**	**156.3**	**22.0**	**23.9**	**376.5**	**57.0**	**786.9**
Year Ended December 31, 2004							
Property acquisition costs							
Unproved	$ 9.7	54.8	—	—	—	6.1	70.6
Proved	—	67.3	—	—	—	—	67.3
Total acquisition costs	9.7	122.1	—	—	—	6.1	137.9
Exploration costs[3]	96.9	10.9	1.0	—	154.1	9.6	272.5
Development costs[3]	107.1	109.1	4.9	12.5	103.3	—	336.9
Total costs incurred	213.7	242.1	5.9	12.5	257.4	15.7	747.3
Charged to expense							
Dry hole expense	41.3	21.4	.7	—	47.4	.1	110.9
Geophysical and other costs	15.7	3.4	.3	—	15.3	2.3	37.0
Total charged to expense	57.0	24.8	1.0	—	62.7	2.4	147.9
Property additions	$156.7	217.3	4.9	12.5	194.7	13.3	599.4
Year Ended December 31, 2003							
Property acquisition costs							
Unproved	$ 19.9	2.9	—	—	—	—	22.8
Proved	—	—	—	—	—	—	—
Total acquisition costs	19.9	2.9	—	—	—	—	22.8
Exploration costs[3]	73.6	23.9	.3	—	68.9	5.1	171.8
Development costs[3]	201.9	49.8	24.5	27.0	121.2	—	424.4
Total costs incurred	295.4	76.6	24.8	27.0	190.1	5.1	619.0
Charged to expense							
Dry hole expense	36.4	2.8	(.1)	—	17.6	3.9	60.6
Geophysical and other costs	15.5	6.2	.4	—	14.0	1.2	37.3
Total charged to expense	51.9	9.0	.3	—	31.6	5.1	97.9
Property additions	$243.5	67.6	24.5	27.0	158.5	—	521.1

1 Excludes property additions for the Company's 5% interest in synthetic oil operations in Canada, which were $112.9 million in 2005, $110.6 million in 2004 and $93.8 million in 2003.

2 Excludes property additions of $4.6 million in 2004 and $49.3 million in 2003 related to discontinued operations.

3 Includes non-cash asset retirement costs as follows:

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
2004							
Exploration costs	$ 1.8	—	—	—	2.6	—	4.4
Development costs	10.6	7.2	1.9	—	(5.4)	—	14.3
	$ 12.4	7.2	1.9	—	(2.8)	—	18.7
2003							
Exploration costs	$ 1.1	—	—	—	—	—	1.1
Development costs	12.5	3.9	—	—	5.7	—	22.1
	$ 13.6	3.9	—	—	5.7	—	23.2

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

(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Malaysia	Other	Subtotal	Synthetic Oil – Canada	Total
Year Ended December 31, 2005									
Revenues									
Crude oil and natural gas liquids									
Transfers to consolidated operations	**$ —**	**48.4**	**—**	**—**	**—**	**—**	**48.4**	**11.3**	**59.7**
Sales to unaffiliated enterprises	**448.8**	**471.3**	**159.8**	**116.6**	**232.9**	**—**	**1,429.4**	**213.4**	**1,642.8**
Natural gas									
Transfers to consolidated companies	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
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**	**116.6**	**232.9**	**—**	**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**	**116.6**	**234.0**	**4.4**	**1,941.3**	**224.7**	**2,166.0**
Costs and expenses									
Production expenses	**70.8**	**58.7**	**18.4**	**25.3**	**35.2**	**—**	**208.4**	**97.0**	**305.4**
Net costs associated with hurricanes	**12.4**	**3.4**	**1.2**	**—**	**.2**	**—**	**17.2**	**1.6**	**18.8**
Exploration costs charged to expense	**45.2**	**7.2**	**4.1**	**1.0**	**101.7**	**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**	**23.5**	**48.9**	**.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**
Selling and general expenses	**22.0**	**8.2**	**2.8**	**1.0**	**7.4**	**9.9**	**51.3**	**.7**	**52.0**
Total costs and expenses	**259.1**	**205.5**	**53.1**	**50.8**	**193.6**	**62.6**	**824.7**	**112.6**	**937.3**
	589.9	**351.1**	**127.6**	**65.8**	**40.4**	**(58.2)**	**1,116.6**	**112.1**	**1,228.7**
Income tax expense	**204.4**	**118.6**	**47.7**	**27.7**	**45.1**	**.7**	**444.2**	**36.4**	**480.6**
Results of operations*	**$385.5**	**232.5**	**79.9**	**38.1**	**(4.7)**	**(58.9)**	**672.4**	**75.7**	**748.1**
Year Ended December 31, 2004									
Revenues									
Crude oil and natural gas liquids									
Transfers to consolidated operations	$ —	31.5	—	—	—	—	31.5	31.3	62.8
Sales to unaffiliated enterprises	248.4	371.8	146.8	30.8	167.2	—	965.0	142.9	1,107.9
Natural gas									
Transfers to consolidated companies	—	—	—	—	—	—	—	—	—
Sales to unaffiliated enterprises	207.6	28.7	11.4	—	—	—	247.7	—	247.7
Total oil and gas revenues	456.0	432.0	158.2	30.8	167.2	—	1,244.2	174.2	1,418.4
Other operating revenues	26.8	.5	39.2	—	—	3.4	69.9	—	69.9
Total revenues	482.8	432.5	197.4	30.8	167.2	3.4	1,314.1	174.2	1,488.3
Costs and expenses									
Production expenses	76.3	39.4	18.8	13.9	22.7	—	171.1	77.9	249.0
Storm damage and estimated retrospective insurance costs	8.7	2.9	2.4	—	.1	—	14.1	1.1	15.2
Exploration costs charged to expense	57.0	24.8	1.0	—	62.7	2.4	147.9	—	147.9
Undeveloped lease amortization	12.8	2.7	—	—	—	.9	16.4	—	16.4
Depreciation, depletion and amortization	66.9	100.8	28.0	5.3	29.6	.1	230.7	10.8	241.5
Accretion of asset retirement obligations	3.7	2.9	2.3	—	.2	.4	9.5	.4	9.9
Selling and general expenses	19.3	9.4	2.8	.6	4.8	9.2	46.1	.6	46.7
Total costs and expenses	244.7	182.9	55.3	19.8	120.1	13.0	635.8	90.8	726.6
	238.1	249.6	142.1	11.0	47.1	(9.6)	678.3	83.4	761.7
Income tax expense	78.6	76.4	55.0	4.4	8.8	1.8	225.0	24.4	249.4
Results of operations*	$159.5	173.2	87.1	6.6	38.3	(11.4)	453.3	59.0	512.3

* Excludes discontinued operations, corporate overhead and interest in 2005 and 2004. Income from discontinued operations was $8.6 million in 2005 and $204.9 million in 2004.

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

(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Malaysia	Other	Subtotal	Synthetic Oil – Canada	Total
Year Ended December 31, 2003									
Revenues									
Crude oil and natural gas liquids									
Transfers to consolidated operations	$ —	33.0	—	—	—	—	33.0	17.0	50.0
Sales to unaffiliated enterprises	39.2	281.8	158.6	41.9	77.7	—	599.2	78.7	677.9
Natural gas									
Transfers to consolidated operations	—	—	—	—	—	—	—	—	—
Sales to unaffiliated enterprises	158.3	34.9	12.2	—	—	—	205.4	—	205.4
Total oil and gas revenues	197.5	349.7	170.8	41.9	77.7	—	837.6	95.7	933.3
Other operating revenues	(.8)	10.9	50.8	—	—	4.2	65.1	—	65.1
Total revenues	196.7	360.6	221.6	41.9	77.7	4.2	902.7	95.7	998.4
Costs and expenses									
Production expenses	36.8	36.4	27.9	16.5	9.1	—	126.7	62.9	189.6
Exploration costs charged to expense	51.9	9.0	.3	—	31.6	5.1	97.9	—	97.9
Undeveloped lease amortization	11.5	3.1	.1	—	—	—	14.7	—	14.7
Depreciation, depletion and amortization	36.7	94.0	32.6	7.5	18.5	.2	189.5	9.1	198.6
Impairment of properties	3.0	—	—	—	—	—	3.0	—	3.0
Accretion of asset retirement obligations	3.3	2.5	2.9	—	.3	.3	9.3	.4	9.7
Selling and general expenses	17.0	12.2	2.7	.6	3.8	6.7	43.0	.6	43.6
Total costs and expenses	160.2	157.2	66.5	24.6	63.3	12.3	484.1	73.0	557.1
	36.5	203.4	155.1	17.3	14.4	(8.1)	418.6	22.7	441.3
Income tax expense	13.2	55.6	59.8	.6	3.7	.7	133.6	4.3	137.9
Results of operations*	$ 23.3	147.8	95.3	16.7	10.7	(8.8)	285.0	18.4	303.4

* Excludes discontinued operations, corporate overhead and interest in 2003. Income from discontinued operations was $22.8 million in 2003.

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

(Millions of dollars)	United States	Canada[1,2]	United Kingdom	Ecuador	Malaysia	Total
December 31, 2005						
Future cash inflows	**$ 4,453.2**	**1,890.3**	**1,494.5**	**607.7**	**2,198.4**	**10,644.1**
Future development costs	**(235.2)**	**(33.9)**	**(39.1)**	**(39.8)**	**(314.2)**	**(662.2)**
Future production and abandonment costs	**(394.6)**	**(577.5)**	**(236.6)**	**(149.1)**	**(332.1)**	**(1,689.9)**
Future income taxes	**(1,164.1)**	**(391.8)**	**(509.9)**	**(118.3)**	**(457.1)**	**(2,641.2)**
Future net cash flows	**2,659.3**	**887.1**	**708.9**	**300.5**	**1,095.0**	**5,650.8**
10% annual discount for estimated timing of cash flows	**(682.1)**	**(156.8)**	**(253.7)**	**(67.9)**	**(301.3)**	**(1,461.8)**
Standardized measure of discounted future net cash flows	**$ 1,977.2**	**730.3**	**455.2**	**232.6**	**793.7**	**4,189.0**
December 31, 2004						
Future cash inflows	$ 3,721.2	1,215.2	1,119.6	401.8	2,119.2	8,577.0
Future development costs	(194.8)	(31.9)	(34.7)	(39.7)	(625.6)	(926.7)
Future production and abandonment costs	(595.7)	(342.0)	(247.9)	(128.7)	(739.4)	(2,053.7)
Future income taxes	(862.3)	(252.9)	(352.9)	(42.4)	(312.9)	(1,823.4)
Future net cash flows	2,068.4	588.4	484.1	191.0	441.3	3,773.2
10% annual discount for estimated timing of cash flows	(485.8)	(75.4)	(173.3)	(45.9)	(210.4)	(990.8)
Standardized measure of discounted future net cash flows	$ 1,582.6	513.0	310.8	145.1	230.9	2,782.4
December 31, 2003						
Future cash inflows	$ 3,787.5	2,239.6	948.2	685.1	544.6	8,205.0
Future development costs	(184.2)	(85.4)	(22.7)	(41.4)	(104.1)	(437.8)
Future production and abandonment costs	(631.1)	(649.5)	(268.8)	(264.6)	(143.2)	(1,957.2)
Future income taxes	(1,001.2)	(419.0)	(265.0)	(116.5)	(129.6)	(1,931.3)
Future net cash flows	1,971.0	1,085.7	391.7	262.6	167.7	3,878.7
10% annual discount for estimated timing of cash flows	(560.7)	(266.2)	(122.9)	(72.7)	(36.3)	(1,058.8)
Standardized measure of discounted future net cash flows	$ 1,410.3	819.5	268.8	189.9	131.4	2,819.9

1 Includes discounted future net cash flows from discontinued operations of $322.2 million at December 31, 2003.

2 Excludes discounted future net cash flows from synthetic oil of $1,201 million at December 31, 2005, $708.6 million at December 31, 2004, and $451.5 million at December 31, 2003.

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

(Millions of dollars)	2005	2004	2003
Net changes in prices, production costs and development costs	**$ 2,758.8**	(1.4)	(97.0)
Sales and transfers of oil and gas produced, net of production costs	**(1,732.9)**	(1,143.0)	(938.8)
Net change due to extensions and discoveries	**406.5**	1,056.5	307.7
Net change due to purchases and sales of proved reserves	**(274.0)**	(272.0)	(196.7)
Development costs incurred	**520.2**	310.7	426.9
Accretion of discount	**414.0**	421.1	420.4
Revisions of previous quantity estimates	**(96.9)**	(443.4)	85.1
Net change in income taxes	**(589.1)**	34.0	31.9
Net increase (decrease)	**1,406.6**	(37.5)	39.5
Standardized measure at January 1	**2,782.4**	2,819.9	2,780.4
Standardized measure at December 31	**$ 4,189.0**	2,782.4	2,819.9

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

(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Malaysia	Other	Subtotal	Synthetic Oil – Canada	Total
December 31, 2005									
Unproved oil and gas properties	**$ 225.3**	**107.8**	**—**	**—**	**213.5**	**72.8**	**619.4**	**—**	**619.4**
Proved oil and gas properties	**756.6**	**1,206.3**	**389.5**	**306.1**	**598.2**	**—**	**3,256.7**	**715.5**	**3,972.2**
Asset retirement costs	**39.9**	**53.3**	**17.2**	**—**	**7.4**	**2.9**	**120.7**	**4.6**	**125.3**
Gross capitalized costs	**1,021.8**	**1,367.4**	**406.7**	**306.1**	**819.1**	**75.7**	**3,996.8**	**720.1**	**4,716.9**
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	**(46.3)**	**(11.2)**	**—**	**—**	**—**	**(6.0)**	**(63.5)**	**—**	**(63.5)**
Proved oil and gas properties	**(274.8)**	**(529.1)**	**(232.9)**	**(212.2)**	**(88.9)**	**—**	**(1,337.9)**	**(105.4)**	**(1,443.3)**
Asset retirement costs	**(10.7)**	**(23.7)**	**(9.7)**	**—**	**(3.5)**	**(2.9)**	**(50.5)**	**(.5)**	**(51.0)**
Net capitalized costs	**$ 690.0**	**803.4**	**164.1**	**93.9**	**726.7**	**66.8**	**2,544.9**	**614.2**	**3,159.1**
December 31, 2004									
Unproved oil and gas properties	$ 210.1	103.9	.1	—	92.7	16.7	423.5	—	423.5
Proved oil and gas properties	1,537.5	1,034.4	368.0	282.2	350.7	—	3,572.8	579.2	4,152.0
Asset retirement costs	62.1	45.9	16.8	—	3.5	3.4	131.7	4.4	136.1
Gross capitalized costs	1,809.7	1,184.2	384.9	282.2	446.9	20.1	4,128.0	583.6	4,711.6
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	(34.2)	(8.2)	(.1)	—	—	(4.3)	(46.8)	—	(46.8)
Proved oil and gas properties	(1,047.9)	(400.6)	(209.8)	(191.6)	(44.6)	—	(1,894.5)	(89.2)	(1,983.7)
Asset retirement costs	(34.9)	(17.7)	(8.6)	—	(2.7)	(3.4)	(67.3)	(.4)	(67.7)
Net capitalized costs	$ 692.7	757.7	166.4	90.6	399.6	12.4	2,119.4	494.0	2,613.4

Note: Unproved oil and gas properties above include costs and associated accumulated amortization for 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, 2005					
Sales and other operating revenues	**$ 2,404.0**	**2,771.7**	**3,311.3**	**3,193.1**	**11,680.1**
Income from continuing operations before income taxes	**203.2**	**562.0**	**353.9**	**253.0**	**1,372.1**
Income from continuing operations	**113.2**	**347.7**	**222.4**	**154.6**	**837.9**
Income from discontinued operations	**—**	**—**	**8.6**	**—**	**8.6**
Net income	**113.2**	**347.7**	**231.0**	**154.6**	**846.5**
Income per Common share – basic[1]					
Continuing operations	**.61**	**1.89**	**1.20**	**.83**	**4.54**
Discontinued operations	**—**	**—**	**.05**	**—**	**.05**
Net income	**.61**	**1.89**	**1.25**	**.83**	**4.59**
Income per Common share – diluted[1]					
Continuing operations	**.60**	**1.85**	**1.18**	**.82**	**4.46**
Discontinued operations	**—**	**—**	**.05**	**—**	**.05**
Net income	**.60**	**1.85**	**1.23**	**.82**	**4.51**
Cash dividend per Common share[1]	**.1125**	**.1125**	**.1125**	**.1125**	**.45**
Market price of Common Stock[1,2]					
High	**52.35**	**54.87**	**55.98**	**55.79**	**55.98**
Low	**38.05**	**43.10**	**48.94**	**42.08**	**38.05**
Year Ended December 31, 2004					
Sales and other operating revenues	$ 1,628.2	2,097.0	2,262.3	2,311.6	8,299.1
Income from continuing operations before income taxes	139.8	257.6	196.4	211.1	804.9
Income from continuing operations	80.7	168.1	115.8	131.8	496.4
Income from discontinued operations	17.5	181.8	2.9	2.7	204.9
Net income	98.2	349.9	118.7	134.5	701.3
Income per Common share – basic[1]					
Continuing operations	.44	.91	.63	.72	2.69
Discontinued operations	.09	.99	.01	.01	1.12
Net income	.53	1.90	.64	.73	3.81
Income per Common share – diluted[1]					
Continuing operations	.43	.90	.62	.71	2.65
Discontinued operations	.09	.97	.01	.01	1.10
Net income	.52	1.87	.63	.72	3.75
Cash dividend per Common share[1]	.10	.10	.1125	.1125	.425
Market price of Common Stock[1,2]					
High	33.49	36.85	43.38	43.15	43.38
Low	29.04	31.45	35.07	38.78	29.04

1 Amounts in 2004 and the first quarter of 2005 have been adjusted to reflect the two-for-one stock split effective June 3, 2005.

2 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[1]	Balance at December 31
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**
Included in liabilities:					
Accrued major repair costs	**44.2**	**35.0**	**(23.7)**	**(.2)**	**55.3**
2004					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 14.3	2.2	(2.8)	.3	14.0
Deferred tax asset valuation allowance	68.1	15.9[2]	—	—	84.0
Included in liabilities:					
Accrued major repair costs	20.5	30.2	(8.0)	1.5	44.2
2003					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 9.3	6.1	(1.5)	.4	14.3
Deferred tax asset valuation allowance	89.6	(21.5)[2]	—	—	68.1
Included in liabilities:					
Accrued major repair costs	53.0	28.5	(61.9)	.9	20.5

1 Amounts represent changes in foreign currency exchange rates.

2 Includes recognition of deferred income tax benefits of $31.9 million in 2004 for Block K and $11.4 million in 2003 for Blocks SK 309 and 311 in Malaysia.

GLOSSARY OF TERMS

3D seismic

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

bitumen or oil sands

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

deepwater

offshore location in greater than 1,000 feet of water

downstream

refining and marketing operations

dry hole

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

exploratory

wildcat and delineation, e.g., exploratory wells

feedstock

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

hydrocarbons

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

ring fenced

a property or area which cannot be consolidated with other properties or areas for purposes of income tax filings

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

1992 STOCK INCENTIVE PLAN

(As Amended May 14, 1997; December 1, 1999, May 14, 2003 and December 7, 2005)

SECTION 1. PURPOSE

The purpose of the Murphy Oil Corporation 1992 Stock Incentive Plan is to foster and promote the long-term financial success of the Company and materially increase shareholder value by (a) motivating superior performance by means of performance-related incentives, (b) encouraging and providing for the acquisition of an ownership interest in the Company by Employees, and (c) enabling the Company to attract and retain the services of an outstanding management team upon whose judgment, interest, and special effort the successful conduct of its operations is largely dependent.

SECTION 2. DEFINITIONS

Unless the context otherwise indicates, the following definitions shall be applicable for the purpose of the 1992 Stock Incentive Plan:

"Agreement" shall mean a written agreement setting forth the terms of an Award.

"Award" shall mean any Option (which may be designated as a Nonqualified or Incentive Stock Option), a Stock Appreciation Right, or a Restricted Stock Award, in each case granted under this Plan.

"Beneficiary" shall mean the person, persons, trust, or trusts designated by an Employee or if no designation has been made, the person, persons, trust or trusts entitled by will or the laws of descent and distribution to receive the benefits specified under this Plan in the event of an Employee's death.

"Board" shall mean the Board of Directors of the Company.

"Code" means the Internal Revenue Code of 1986, as amended.

"Committee" shall mean the Executive Compensation Committee of the Board, as from time to time constituted, or any successor committee of the Board with similar functions. The Committee shall be constituted to comply with the requirements of Rule 16b-3 promulgated by the Securities and Exchange Commission under the Securities Exchange Act of 1934, or such rule or any successor rule thereto which is in effect from time to time.

"Common Stock" shall mean the Common Stock of the Company, $1.00 par value, subject to adjustment pursuant to Section 11.

“Company” shall mean Murphy Oil Corporation, a Delaware corporation.

“Employee” shall mean any person employed by the Company on a full-time salaried basis or by a Subsidiary that does not have in effect for its personnel any plan similar to the Plan, including officers and employee directors thereof.

“Incentive Stock Option” or “ISO” shall mean an Option that is intended by the Committee to meet the requirements of Section 422 of the Code or any successor provision.

“Nonqualified Stock Option” or “NQSO” shall mean an Option granted pursuant to this Plan which does not qualify as an Incentive Stock Option.

“Normal Termination” shall mean a termination of employment (i) at normal retirement time, (ii) for permanent and total disability, or (iii) with Company approval, and without being terminated for cause.

“Option” shall mean the right to purchase Common Stock at a price to be specified and upon terms to be designated by the Committee pursuant to this Plan. An Option shall be designated by the Committee as a Nonqualified Stock Option or an Incentive Stock Option at the time of grant.

“Opportunity Shares” shall mean additional shares of Common Stock which may be earned by an Employee pursuant to Section 8.

“Option Holder” or “Holder” shall mean an Employee to whom an option has been granted.

“Personal Representative” shall mean the person or persons who, upon the disability or incompetence of an Employee, shall have acquired on behalf of the Employee by legal proceeding or otherwise the right to receive the benefits specified in this Plan.

“Plan” shall mean this 1992 Stock Incentive Plan.

“Restricted Period” shall mean the period designated by the Committee during which Restricted Stock may not be sold, assigned, transferred, pledged, or otherwise encumbered and during which such stock is subject to forfeiture.

“Restricted Stock” shall mean those shares of Common Stock issued pursuant to a Restricted Stock Award which are subject to the restrictions, terms, and conditions specified by the Committee pursuant to Section 8.

“Restricted Stock Award” shall mean an award of Restricted Stock pursuant to Section 8 hereof.

"Stock Appreciation Right" or "SAR" shall mean the right of the holder to receive, upon exercise thereof, payment of an amount determined by multiplying: (a) any increase in the Fair Market Value of a share of Common Stock at the date of exercise over the price fixed by the Committee at the date of grant, by (b) the number of shares with respect to which the SAR is exercised; provided, however, that at the time of grant, the Committee may establish, in its sole discretion, a maximum amount per share which will be payable upon exercise of a SAR. The amount payable upon exercise may be paid in cash or other property, including without limitation, shares of Common Stock, or any combination thereof as determined by the Committee.

SECTION 3. ADMINISTRATION

The Plan shall be administered by the Committee. In addition to any implied powers and duties that may be needed to carry out the provisions of the Plan, the Committee shall have all of the powers vested in it by the terms of the Plan, including exclusive authority to select the Employees to be granted Awards under the Plan, to determine the type, size and terms of the Awards to be made to each Employee selected, to determine the time when Awards will be granted, and to prescribe the form of the Agreements embodying Awards made under the Plan. No member of the Committee, while he serves on the Committee, may be granted Awards under the Plan. The Committee shall be authorized to interpret the Plan and the Awards granted under the Plan, to establish, amend and rescind any rules and regulations relating to the Plan, to make any other determinations which it believes necessary or advisable for the administration of the Plan, and to correct any defect or supply any omission or reconcile any inconsistency in the Plan or in any Award in the manner and to the extent the Committee deems desirable to carry it into effect. Any decision of the Committee in the administration of the Plan, as described herein, shall be final and conclusive.

The Board may from time to time remove members from the Committee or add members thereto, and vacancies in the Committee, however caused, shall be filled by action of the Board. The Committee shall select one of its members as chairman and shall hold its meetings at such time and places as it may determine. The Committee may act only by a majority of its members. The members of the Committee may receive such compensation for their services as the Board may determine. Any determination of the Committee may be made, without notice, by the written consent of the majority of the members of the Committee. In addition, the Committee may authorize any one or more of their number or any officer of the Company to execute and deliver documents on behalf of the Committee.

SECTION 4. STOCK SUBJECT TO THE PLAN

The maximum number of shares available for Awards under the Plan in each calendar year during any part of which the Plan shall be in effect shall be one percent (1%) of the total issued and outstanding shares as of December 31 of the immediately preceding year, subject to Section 11 of the Plan. Any and all such shares may be issued in respect of any of the types of Awards; provided, however, no more than fifty percent (50%) of the shares available shall be subject to Incentive Stock Options granted under the Plan and that no more than fifty percent (50%) of the shares available for Awards under the Plan shall be issued in respect of Restricted Stock.

Unless otherwise determined by the Committee, all shares available in any year that are not granted under the Plan will not be available for grant for subsequent years. "Maximum Grants." Notwithstanding any provision contained in this Plan to the contrary, the maximum number of shares of Common Stock for which Incentive Stock Options, Nonqualified Stock Options, and Stock Appreciation Rights may be granted under the Plan to any one Employee for any calendar year is 400,000.

If any shares of Common Stock subject to an Award hereunder are forfeited or any such Award otherwise terminates without the issuance of shares of Common Stock or other consideration to an Employee, such shares shall not increase the number of shares available for grant in such year.

SECTION 5. ELIGIBILITY

Any Employee who is a director or an officer or who serves in any other key administration, professional or technical capacity shall be eligible to participate in the Plan. In addition the Committee may in any year include any other Employee who the Committee has determined has made some unusual contribution which would not be expected of such Employee in the ordinary course of his work.

SECTION 6. STOCK OPTIONS

A. Grant of Options and Price

(a) Any Option granted under the Plan may be granted as an Incentive Stock Option or as a Nonqualified Stock Option as shall be designated by the Committee at the time of the grant of such Option. Each Option shall be evidenced by an Agreement between the recipient and the Company, which Agreement shall specify the designation of the Option as an ISO or a NQSO, as the case may be, and shall contain such terms and conditions not inconsistent with the Plan as the Committee, in its sole discretion, may determine in accordance with the Plan.

(b) The exercise price for the purchase of Common stock to be issued pursuant to each Option shall be fixed by the Committee at the time of the granting of the Option provided, however, that such exercise price shall in no event be less than the fair market value of the Common Stock on the date such Option is granted.

B. Exercise

The period during which an Option may be exercised shall be determined by the Committee; provided, that such period will not be longer than ten years from the date on which the Option is granted. The date or dates on which portions of an Option may be exercised during the term of an Option shall be determined by the Committee. In no case may an Option be exercised at any time for fewer than 50 shares (or the total remaining shares covered by the Option if fewer than 50 shares) during the term of the Option. An Option which is granted in tandem with a SAR may only be exercised upon the surrender of the right to exercise such SAR for an equivalent number of shares.

C. Payment of Shares

The exercise price for the Common Stock shall be paid in full when the Option is exercised. Subject to such rules as the Committee may impose, the exercise price may be paid in whole or in part in (i) cash, (ii) whole shares of Common Stock evidenced by negotiable certificates, valued at their fair market value on the date of exercise, (iii) by a combination of such methods of payment, or (iv) such other consideration as shall be approved by the Committee.

SECTION 7. STOCK APPRECIATION RIGHTS

Stock Appreciation Rights may be granted to participants at such time or times as shall be determined by the Committee and shall be subject to such terms and conditions as the Committee may impose. A grant of a SAR shall be made pursuant to a written agreement containing such provisions not inconsistent with the Plan as the Committee shall approve.

SARs may be exercised at such times or subject to such conditions as the Committee shall impose, either at or after the time of grant. SARs which are granted in tandem with an Option may only be exercised upon the surrender of the right to exercise such Option for an equivalent number of shares and may be exercised only with respect to the shares of Stock for which the related Option is then exercisable. Option shares with respect to which a tandem SAR shall have been exercised for cash shall not again be available for an Award under this Plan. Notwithstanding any other provision of the Plan, the Committee may impose such conditions on the exercise of a SAR (including, without limitation, the right of the Committee to limit the time of exercise to specified periods) as may be required to satisfy the applicable provisions of Rule 16b-3 as promulgated under the Securities Exchange Act of 1934, as amended (the “Exchange Act”).

SECTION 8. RESTRICTED STOCK AWARDS

The Committee may make an award of Restricted Stock to selected Employees, evidenced by an Agreement which shall contain such terms and conditions, including without limitation, forfeiture provisions, as the Committee, in its sole discretion, may determine. The amount of each Restricted Stock Award and the respective terms and conditions of each Award (which terms and conditions need not be the same in each case) shall be determined by the Committee in its sole discretion.

The Committee shall establish performance measures for each Restricted Period on the basis of such criteria and to accomplish such objectives as the Committee may from time to time, in its sole discretion, determine. Such measures may include, but shall not be limited to, total shareholder return, growth in cash flow per share, growth in earnings per share, return on assets, or return on stockholder equity. The Committee may from time to time establish different performance objectives for certain operating subsidiaries or sectors of the business. The maximum number of shares of restricted stock which can be granted pursuant to the Plan will be 200,000 shares per year to any one Employee. Currently, the performance criteria for the determination of the performance-based restricted shares is the 5-year total shareholder return for Murphy

Oil Corporation as compared to a peer group of six companies. The Committee may from time to time establish a different performance criteria.

Shares of Restricted Stock will be subject to forfeiture and may not be sold, transferred, pledged, assigned, or otherwise alienated or hypothecated until such time or until the satisfaction of such conditions or the occurrence of such events as shall be determined by the Committee either at or after the time of grant. Unless otherwise determined by the Committee at the time of grant, participants holding shares of Restricted Stock granted hereunder may exercise full voting rights with respect to those shares during the Restricted Period.

Unless otherwise determined by the Committee at the time of grant, participants holding shares of Restricted Stock shall be entitled to receive all dividends and other distributions paid with respect to those shares, provided that if any such dividends or distributions are paid in shares of Stock or other securities, such shares or securities shall be subject to the same forfeiture restrictions and restrictions on transferability as apply to the Restricted Stock with respect to which they were paid.

Each Employee who has received shares of Common Stock pursuant to a Restricted Stock Award with respect to which all of the restrictions set forth in Section 8 shall have lapsed or pursuant to an award of Opportunity Shares related to such Restricted Stock Award shall also receive from the Company a cash payment in the year following the close of the Restricted Period in an amount determined by the Committee, which amount is intended to allow such Employee to pay such Employee's tax liability (assuming the highest rates of tax applicable to any individual taxpayer in the year in which such payment is made) with respect to (i) such shares and (ii) such cash payment. Provided, however, unless otherwise determined by the Committee, the cash payment shall in no event exceed 50% of the fair market value of such shares as of the date that all of the restrictions set forth in Section 8 shall have lapsed or as to an award of Opportunity Shares as of the date of grant thereof.

SECTION 9. TERMINATION OF EMPLOYMENT

Unless otherwise determined by the Committee at the time of grant, in the event a participant's employment terminates by reason of Normal Termination, any Options granted to such participant which are then outstanding may be exercised at the earlier of any time prior to the expiration of the term of the Options or within two (2) years after termination and any shares of Restricted Stock then outstanding shall be prorated for all restricted periods then in effect based on the number of months of actual participation.

Unless otherwise determined by the Committee at the time of grant, in the event a participant's employment is terminated by reason of death, any Options granted to such participant which are then outstanding may be exercised by the participant's beneficiary or the participant's legal representative at any time prior to the expiration date of the term of the Options or within two (2) years following the participant's termination of employment, whichever period is shorter, and any shares of Restricted Stock then outstanding shall be prorated for all restricted periods then in effect based on the number of months of actual participation.

Unless otherwise determined by the Committee at the time of grant, in the event the employment of the participant shall terminate for any reason other than the ones described in this Section, any Options granted to such participant which are then outstanding shall be canceled and any shares of Restricted Stock then outstanding as to which the Restricted Period has not lapsed shall be forfeited.

A change in employment from the Company or one Subsidiary to another Subsidiary of the Company shall not be considered a termination.

SECTION 10. CHANGE IN CONTROL

Unless the Committee shall otherwise determine, notwithstanding any other provision of this Plan or an Agreement to the contrary, upon a Change in Control, as defined below, all outstanding Awards shall vest, become immediately exercisable or payable or have all restrictions lifted as may apply to the type of Award.

A “Change in Control” shall be deemed to have occurred if (i) any “person”, including a “group” (as such terms are used in Sections 13(d) and 14(d)(2) of the Exchange Act, but excluding the Company, any of its subsidiaries or any employee benefit plan of the Company or any of its subsidiaries or Charles H. Murphy, Jr. and affiliates of Charles H. Murphy, Jr.) is or becomes the “beneficial owner” (as defined in Rule 13(d)(3) under the Exchange Act), directly or indirectly, of securities of the Company representing 25% or more of the combined voting power of the Company’s then outstanding securities; or (ii) the stockholders of the Company shall approve a definitive agreement (1) for the merger or other business combination of the Company with or into another corporation a majority of the directors of which were not directors of the Company immediately prior to the merger and in which the stockholders of the Company immediately prior to the effective date of such merger own less than 50% of the voting power in such corporation or (2) for the sale or other disposition of all or substantially all of the assets of the Company.

SECTION 11. ADJUSTMENTS UPON CHANGES IN CAPITALIZATION

In the event of any change in the Common Stock by reason of any stock split, stock dividend, recapitalization, merger, consolidation, reorganization, combination, or exchange of shares, split-up, spin-off, share purchase, liquidation or other similar change in capitalization affecting or involving the Common Stock, or any distribution to common stockholders other than regular cash dividends, the Committee shall make such substitution or adjustment, if any, as it deems equitable, as to the number or kind of shares that may be issued under the Plan pursuant to Section 4 and the number or kind of shares subject to, or the price per share under or terms of any outstanding Award. The amount and form of the substitution or adjustment shall be determined by the Committee and any such substitution or adjustment shall be conclusive and binding on all parties for all purposes of the Plan.

SECTION 12. MISCELLANEOUS PROVISIONS

(a) No Employee or other person shall have any claim or right to be granted an Award under the Plan and no Award shall confer any right to continued employment.

(b) An Employee's rights and interest under the Plan or any Award may not be assigned or transferred in whole or in part, either directly or by operation of law or otherwise (except in the event of an Employee's death, to the Employee's Beneficiaries or by will or the laws of descent and distribution), including, but not by way of limitation, execution, levy, garnishment, attachment, pledge, bankruptcy or in any other manner, and no such right or interest of any Employee in the Plan or in any Award shall be subject to any obligation or liability of such individual. An Award shall be exercisable, during an Employee's lifetime, only by him or her or his or her Personal Representative. Except as specified in the applicable Award agreement, the holder of an Award shall have none of the rights of a shareholder until the shares subject thereto shall have been registered on the transfer books of the Company.

(c) Any provision of the Plan or any Agreement to the contrary notwithstanding, no Common Stock shall be issued hereunder unless counsel for the Company shall be satisfied that such issuance will be in compliance with applicable Federal, state, or other securities laws.

(d) The Company shall have the power to withhold, or require a participant to remit to the Company, an amount sufficient to satisfy Federal, state, and local withholding tax requirements in respect of any Award, or any exercise or vesting thereof under the Plan, and the Company may defer payment of cash or issuance of Stock until such requirements are satisfied. The Committee may, in its discretion, permit an Employee to elect, subject to such conditions as the Committee shall impose, (i) to have shares of Stock otherwise issuable under the Plan withheld by the Company or (ii) to deliver to the Company previously acquired shares of Stock, in either case having a fair market value sufficient to satisfy all or part of the participant's estimated total Federal, state, and local tax obligation associated with the transaction.

(e) The expense of the Plan shall be borne by the Company, except as set forth above in subsection (d) of this Section.

(f) Awards granted under the Plan shall be binding upon the Company, its successors and assigns.

(g) Nothing contained in this Plan shall prevent the Board of Directors from adopting other or additional compensation arrangements, subject to shareholder approval if such approval of any such additional arrangement is required.

SECTION 13. AMENDMENT, MODIFICATION, AND TERMINATION OF PLAN

The Board may from time to time amend the Plan or any provision thereof without the consent of the stockholders except in the case of any amendments that require stockholder approval in order to comply with the applicable provisions of Rule 16b-3.

The Board may terminate the Plan in whole or in part at any time provided that no such termination shall impair the terms of Awards then outstanding under which the obligations of the Company have not been fully discharged. Unless terminated prior, the Plan shall terminate on May 31, 2008. No extension of this date may be implemented without stockholder approval.

SECTION 14. GOVERNING LAW

The provisions of this Plan shall be interpreted and construed in accordance with the laws of the State of Delaware.

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

	Years Ended December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
Income from continuing operations before income taxes	$1,372,059	804,936	374,205	121,566	438,972
Distributions (less than) greater than equity in earnings of affiliates	(5,514)	(4,225)	(209)	(3)	(365)
Previously capitalized interest charged to earnings during period	15,564	14,065	10,457	7,748	3,450
Interest and expense on indebtedness	8,765	34,064	20,511	26,968	19,006
Interest portion of rentals*	9,397	7,908	9,857	9,445	7,953
Earnings before provision for taxes and fixed charges	**$1,400,271**	**856,748**	**414,821**	**165,724**	**469,016**
Interest and expense on indebtedness, excluding capitalized interest	$ 8,765	34,064	20,511	26,968	19,006
Capitalized interest	38,539	22,160	37,240	24,536	20,283
Interest portion of rentals*	9,397	7,908	9,857	9,445	7,953
Total fixed charges	**$ 56,701**	**64,132**	**67,608**	**60,949**	**47,242**
Ratio of earnings to fixed charges	**24.7**	**13.4**	**6.1**	**2.7**	**9.9**

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

FINANCIAL AND OPERATING HIGHLIGHTS

(Thousands of dollars except per share data)	2005	2004	% Change 2005–2004	2003	% Change 2004–2003
For the Year					
Revenues	**$11,877,151**	$8,359,839	42%	$5,164,657	62%
Net income	**846,452**	701,315	21%	294,197	138%
Income from continuing operations	**837,903**	496,395	69%	278,410	78%
Cash dividends paid	**83,198**	78,205	6%	73,464	6%
Capital expenditures [1]	**1,329,831**	975,393	36%	906,114	8%
Net cash provided by operating activities	**1,225,262**	1,097,018	12%	652,278	68%
Average common shares outstanding – diluted (thousands) [2]	**187,889**	186,887	0.5%	185,486	0.8%
At End of Year					
Working capital	**$ 551,938**	$ 424,372	30%	$ 228,529	86%
Net property, plant and equipment	**4,374,229**	3,685,594	19%	3,530,800	4%
Total assets	**6,368,511**	5,458,243	17%	4,712,647	16%
Long-term debt	**609,574**	613,355	-1%	1,090,307	-44%
Stockholders’ equity	**3,460,990**	2,649,156	31%	1,950,883	36%
Per Share of Common Stock					
Net income – diluted	**$ 4.51**	$ 3.75	20%	$ 1.59	136%
Income from continuing operations – diluted	**4.46**	2.65	68%	1.50	77%
Cash dividends paid	**.45**	.425	6%	.40	6%
Stockholders’ equity	**18.61**	14.39	29%	10.62	35%
Net Crude Oil and Gas Liquids Produced – barrels per day [1]	**101,349**	93,634	8%	76,620	22%
United States	**25,897**	19,314	34%	4,526	327%
Canada	**46,086**	43,689	5%	44,935	-3%
Other International	**29,366**	30,631	-4%	27,159	13%
Net Natural Gas Sold – thousands of cubic feet per day [1]	**90,198**	109,452	-18%	111,791	-2%
United States	**70,452**	88,621	-21%	82,281	8%
Canada	**10,323**	13,972	-26%	19,946	-30%
United Kingdom	**9,423**	6,859	37%	9,564	-28%
Crude Oil Refined – barrels per day	**135,122**	164,275	-18%	119,281	38%
North America	**108,139**	133,242	-19%	90,869	47%
United Kingdom	**26,983**	31,033	-13%	28,412	9%
Petroleum Products Sold – barrels per day	**358,255**	338,908	6%	264,928	28%
North America	**322,714**	301,801	7%	229,876	31%
United Kingdom	**35,541**	37,107	-4%	35,052	6%
Stockholder and Employee Data					
Common shares outstanding (thousands) [2,3]	**185,947**	184,071	1.0%	183,741	0.2%
Number of stockholders of record [3]	**2,847**	2,864	-0.6%	2,839	0.9%
Number of employees [3]	**6,248**	5,826	7%	4,789	22%
Average number of employees	**6,127**	5,276	16%	4,446	19%

1 From continuing operations.

2 2004 and 2003 adjusted for two-for-one stock split effective June 3, 2005.

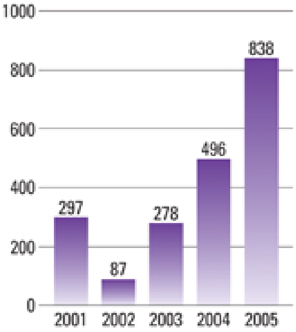
3 At December 31.

Dear Fellow Shareholders,

Some years are more memorable than others and 2005 was one of those years. Hurricane Katrina's devastation of the Gulf Coast and its impact on our Company and employees are undoubtedly the most obvious reasons from a personal and Company point of view. From an industry perspective, however, I would suggest that 2005 will be memorable as the first year of widespread awareness of the increasing strain placed on the world's conventional crude oil supplies. Simply put, it is becoming more difficult for our industry to make new discoveries of sufficiently large fields to accomplish the tandem task of replacing depletion and providing for demand growth. What does this mean? For starters, crude oil prices find support at higher levels as conventional reserves are priced at replacement cost levels substantially higher than in the recent past. In addition, it is now clear that unconventional reserves (e.g. Syncrude) will play an increasingly larger role in supplying hydrocarbons for the world's economy. Furthermore, alternative fuels will slowly add market share, although this share will likely remain very small for the foreseeable future and typically will be supported by taxpayer subsidies.

Our company is very well suited to this changing energy world. Certainly, we are extremely strong financially. In 2005, Murphy earned record net income of $846.5 million ($4.51 per share) easily surpassing the previous record mark set in 2004. Even excluding nonrecurring items such as gains on asset sales and mindful that most of our Gulf of Mexico production was shut-in and the Meraux Refinery offline the last four months of the year, our earnings were above all previous years. Our cash flow from operations in 2005 was $1.22 billion. The balance sheet remains rock solid with debt to total capitalization at 15 percent. Clearly we are in the soundest financial condition

Income from Continuing Operations
Millions of dollars



in our history and have, so far, funded the build-out of the $1.5 billion Kikeh (80%) development from cash flow.

We are also well positioned from a resource standpoint. In 2006, your company adds natural gas production from the Seventeen Hands field (37.5%) in the deep water Gulf of Mexico and oil production from the third major expansion at Syncrude (5%) and from the Seal area (50-100%), both located in northern Alberta, Canada. A large surge of production growth occurs in 2007 as Kikeh starts up in the second half of the year. Also in the queue are the Kenarong and Pertang (75%) natural gas fields offshore Peninsular Malaysia that are waiting for a gas market to develop and the large Kakap-Gumusut oil field located near Kikeh that is shared with and operated by another company. As you can see, we will be growing for the foreseeable future and are well placed to capture what the energy markets are offering.

We realize that in a world of ever increasing demand for hydrocarbons, driven by the emergence of India and China firmly into the global market economy, the ownership of long-lived, large conventional oil and gas fields such as Hibernia, Terra Nova and, now, Kikeh and Kakap-Gumusut, supplemented by unconventional resources such as Syncrude, provide unique growth and profit opportunities. These assets form the basis of our Company, which is set to increase production through the beginning of the second decade of this century.

Murphy's downstream business is anchored by one of the fastest-growing, highest-volume retail gasoline networks in the United States. By the end of 2005 we had 864 sites in operation located in the parking lots of Wal-Mart Supercenters and we anticipate crossing the 1,000 site mark shortly after the end of 2006. This sales channel acts as an important cushion against declining crude oil prices and contributed significantly to the Company's downstream profits in 2005.

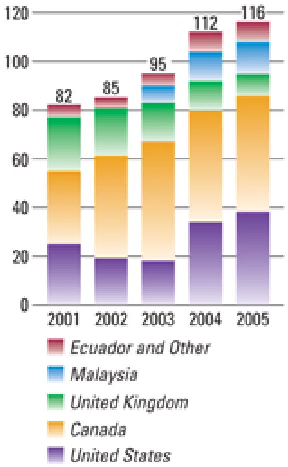
Capital Expenditures by Function
Millions of dollars

The Company's United Kingdom downstream company – Murco Petroleum – reported record earnings in 2005. This very efficient operation provided important profit contributions in the third and fourth quarter after Meraux went offline. We acquired an additional 68 retail stations during the year to complement our existing chain allowing Murco to sell more of its product into the U.K. retail market. Importantly, these sites have been profitable from the moment acquired.

Hurricane Katrina hit the Meraux Refinery in St. Bernard Parish head on. The hurricane caused a storm surge to overtop the two levee systems protecting St. Bernard Parish sending a wall of water into the area. The entire Parish was flooded with the refinery processing units having between two and six feet of water and the tank farm up to 18 feet. The day after the hurricane struck, we began manning the plant, initially coming in by boat on the Mississippi River, a five hour one-way trip. In addition, the truck terminal at the plant was open and manned the day following the hurricane and supplied fuel free of charge to emergency response vehicles in St. Bernard Parish. For over 30 days, this was the primary and, in many cases, the only source of essential fuel used to save lives. As of this writing, the refinery is still under repair and renovation. It is a very large job with every unit being worked on and most pumps, motors, electronic controls and wiring being replaced. We will start coming back up during the first half of April.

One of our storage tanks was dislodged by the storm surge and was damaged. Three days later when the storm waters receded, oil leaked into the area surrounded by our containment levees but approximately 3,000 barrels escaped through a breach in the containment levees. As the storm waters were receding, oil moved on top of the waters into the adjacent areas. We have now cleaned the oil from public areas (streets and sidewalks) and we are well along in our clean-up program for impacted residences. In addition, we set up claims

Net Hydrocarbons Produced from Continuing Operations
Thousands of oil equivalent barrels per day



Claiborne P. Deming
President and Chief Executive Officer

offices around the Gulf Coast and offered to pay settlements to affected residents and clean up the affected properties. It is important to note that these homes had already been flooded with water up to rooflines for days before the spill occurred. Furthermore, the ATSDR, an arm of the U.S. Department of Health, has issued a finding that if the oil is removed to applicable standards, there will be no long-term health impacts to returning residents in the affected area. Our clean-up efforts started two days after the spill was discovered. Our settlement program began two months after the storm, after we performed testing to ascertain the area impacted by the oil. This is an achievement of which I am extremely proud for I believe we have responded forthrightly, fairly and efficiently.

In closing, I would like to thank the employees of this organization for their response to Katrina. I have always known that the individuals in this enterprise understood their responsibilities and met them. It is not until you experience an event like Katrina, however, that shut off the Company's Gulf of Mexico production, closed our refinery, displaced virtually all of our Meraux employees and our U.S. exploration and production office staff in New Orleans (who set up shop in Lafayette within two weeks) that you see first hand the commitment and honor of our people. I have never been more proud to be part of Murphy Oil Corporation.

Claiborne P. Deming

President and Chief Executive Officer

February 10, 2006

El Dorado, Arkansas

	2005	2004	2003	2002	2001	2000
Net crude oil and condensate production – barrels per day						
United States	**25,777**	19,154	4,374	3,837	4,339	4,770
Canada – light	**160**	168	582	1,256	1,981	2,055
heavy	**11,806**	5,838	4,705	3,609	4,521	3,010
offshore	**23,124**	25,407	28,534	24,037	9,535	9,199
synthetic	**10,593**	11,794	10,483	11,362	10,479	8,443
United Kingdom	**7,955**	10,800	14,513	18,180	20,049	20,679
Ecuador	**7,871**	7,735	5,172	4,544	5,319	6,405
Malaysia	**13,503**	11,885	7,301	—	—	—
Net natural gas liquids production – barrels per day						
United States	**120**	160	152	291	413	551
Canada	**403**	482	631	311	540	182
United Kingdom	**37**	211	173	122	165	216
Continuing operations	**101,349**	93,634	76,620	67,549	57,341	55,510
Discontinued operations	**—**	3,106	6,832	8,821	10,014	9,749
Total liquids produced	**101,349**	96,740	83,452	76,370	67,355	65,259
Net crude oil and condensate sold – barrels per day						
United States	**25,777**	19,154	4,374	3,837	4,339	4,769
Canada – light	**160**	168	582	1,256	1,981	2,055
heavy	**11,806**	5,838	4,705	3,609	4,521	3,010
offshore	**22,443**	26,306	28,542	23,935	9,862	9,456
synthetic	**10,593**	11,794	10,483	11,362	10,479	8,443
United Kingdom	**8,247**	10,800	14,591	18,209	20,206	20,921
Ecuador	**9,821**	3,414	4,997	4,293	5,381	6,393
Malaysia	**13,818**	11,020	7,235	—	—	—
Net natural gas liquids sold – barrels per day						
United States	**120**	160	152	291	413	551
Canada	**403**	482	631	311	540	182
United Kingdom	**56**	124	131	149	148	216
Continuing operations	**103,244**	89,260	76,423	67,252	57,870	55,996
Discontinued operations	**—**	3,106	6,832	8,821	10,014	9,749
Total liquids sold	**103,244**	92,366	83,255	76,073	67,884	65,745
Net natural gas sold – thousands of cubic feet per day						
United States	**70,452**	88,621	82,281	88,067	112,616	141,373
Canada	**10,323**	13,972	19,946	12,709	25,701	9,590
United Kingdom	**9,423**	6,859	9,564	6,973	13,125	10,850
Continuing operations	**90,198**	109,452	111,791	107,749	151,442	161,813
Discontinued operations	**—**	30,760	103,543	189,182	129,793	67,599
Total natural gas sold	**90,198**	140,212	215,334	296,931	281,235	229,412
Net hydrocarbons produced – equivalent barrels[1,2] per day	**116,382**	120,109	119,341	125,859	114,228	103,494
Estimated net hydrocarbon reserves – million equivalent barrels[1,2,3]	**353.6**	385.6	425.5	455.3	501.2	442.3
Weighted average sales prices[4]						
Crude oil and condensate – dollars per barrel						
United States	**$ 47.48**	35.35	24.22	24.25	24.92	30.38
Canada[5] – light	**52.47**	37.70	27.68	22.81	21.73	29.98
heavy	**21.30**	20.26	12.36	16.83	11.21	16.74
offshore	**51.37**	36.60	27.08	25.36	23.77	27.16
synthetic	**58.12**	40.35	24.97	25.64	25.04	29.62
United Kingdom	**52.83**	36.82	29.59	24.39	24.44	27.78
Ecuador	**32.54**[6]	24.78	22.99	19.64	17.00	22.01
Malaysia	**46.16**[7]	41.35	29.42	—	—	—
Natural gas liquids – dollars per barrel						
United States	**35.09**	29.77	23.42	17.13	20.40	23.04
Canada[5]	**40.90**	30.83	24.63	16.98	20.78	22.98
United Kingdom	**34.77**	26.91	22.49	18.28	19.12	23.64
Natural gas – dollars per thousand cubic feet						
United States	**8.52**	6.45	5.29	3.37	4.64	4.01
Canada[5]	**7.88**	5.64	4.47	2.59	3.54	4.68
United Kingdom[5]	**5.80**	4.52	3.50	2.76	2.52	1.81

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 Includes price attained in 2005 for recoupment of a portion of 2004 crude oil production owed to the Company in Block 16. Excluding this recoupment, the 2005 average price would have been $34.87 per barrel.
7 Price is net of a payment under the terms of the production sharing contract for Block SK 309.

	2005	2004	2003	2002	2001	2000
Refining						
Crude capacity* of refineries – barrels per stream day	**192,400**	192,400	192,400	167,400	167,400	167,400
Refinery inputs – barrels per day						
Crude – Meraux, Louisiana	**73,371**	101,644	60,403	83,721	104,345	103,154
Superior, Wisconsin	**34,768**	31,598	30,466	30,468	35,869	34,159
Milford Haven, Wales	**26,983**	31,033	28,412	29,640	26,985	28,507
Other feedstocks	**9,131**	12,170	10,113	11,013	9,901	8,298
Total inputs	**144,253**	176,445	129,394	154,842	177,100	174,118
Refinery yields – barrels per day						
Gasoline	**54,869**	68,663	52,162	63,409	73,217	75,106
Kerosine	**7,805**	7,734	6,568	9,446	12,874	11,955
Diesel and home heating oils	**48,535**	66,225	41,277	48,344	52,660	49,606
Residuals	**18,231**	17,445	14,595	16,589	20,530	18,524
Asphalt, LPG and other	**13,268**	14,693	11,986	12,651	13,467	14,624
Fuel and loss	**1,545**	1,685	2,806	4,403	4,352	4,303
Total yields	**144,253**	176,445	129,394	154,842	177,100	174,118
Average cost of crude inputs to refineries – dollars per barrel						
North America	**$ 54.10**	40.00	29.79	24.76	23.44	28.82
United Kingdom	**56.15**	39.60	30.24	25.83	24.86	29.29
Marketing						
Products sold – barrels per day						
North America – Gasoline	**233,191**	207,786	162,911	112,281	96,597	76,314
Kerosine	**5,671**	4,811	4,388	5,818	9,621	8,517
Diesel and home heating oils	**60,228**	66,648	43,373	35,995	41,064	39,347
Residuals	**15,330**	13,699	10,972	13,759	17,308	15,163
Asphalt, LPG and other	**8,294**	8,857	8,232	8,574	9,666	10,271
	322,714	301,801	229,876	176,427	174,256	149,612
United Kingdom – Gasoline	**12,739**	11,435	12,101	12,058	11,058	11,622
Kerosine	**2,410**	2,756	2,526	2,685	2,547	2,478
Diesel and home heating oils	**14,910**	14,649	13,506	14,574	11,798	9,760
Residuals	**3,242**	4,062	3,816	3,127	3,538	3,852
LPG and other	**2,240**	4,205	3,103	1,760	2,121	2,191
	35,541	37,107	35,052	34,204	31,062	29,903
Total products sold	**358,255**	338,908	264,928	210,631	205,318	179,515
Branded retail outlets*						
North America – Murphy USA	**864**	752	623	506	387	276
Other	**337**	375	371	408	428	436
Total	**1,201**	1,127	994	914	815	712
United Kingdom	**412**	358	384	416	411	386

* At December 31.

In 2005, Murphy continued to expand its high-volume Murphy USA brand by adding 112 stations in the Company's 21-state marketing area.

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

George S. Dembroski
Vice Chairman, Retired, RBC Dominion
Securities Limited, Toronto, Ontario, Canada.
Director since 1995.
Committees: Executive; Audit; Executive Compensation (Chairman)

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

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; Executive Compensation

David J. H. Smith
Chief Executive Officer, Retired,
Whatman plc, Maidstone, Kent, England.
Director since 2001.
Committees: Executive Compensation;
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)

1. David Smith 2. Neal Schmale 3. Madison Murphy
4. Frank Blue 5. George Dembroski 6. Ivar Ramberg
7. Caroline Theus 8. Robert Hermes
9. Claiborne Deming 10. William Nolan Jr.

PRINCIPAL SUBSIDIARIES

Murphy Exploration & Production Company – USA Engages in crude oil and natural gas exploration and production in the Gulf of Mexico and in Gulf Coast areas onshore.	131 South Robertson Street New Orleans Louisiana 70112 (504) 561-2811 Temporarily relocated to: 201 Energy Parkway, Suite 310 Lafayette, Louisiana 70508 (337) 267-9123	**John C. Higgins** President **S.J. Carboni, Jr.** Vice President, Deepwater Development and Production **James R. Murphy** Vice President, Exploration **Steven A. Cossé** Vice President and General Counsel	**Kevin G. Fitzgerald** Treasurer **Gasper F. Bivalacqua** Controller **Walter K. Compton** Secretary
Murphy Oil Company Ltd. Engages in crude oil and natural gas exploration and production, extraction and sale of synthetic crude oil, and marketing of petroleum products in Canada.	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	**Harvey Doerr** President **Steve C. Crosby** Vice President, East Coast and Northern Canada **W. Patrick Olson** Vice President, Production	**Marty L. Proctor** Vice President, Exploitation **Kevin G. Fitzgerald** Treasurer **Heather J. Jones** Controller **Georg R. McKay** Secretary
Murphy Exploration & Production Company – International Engages in crude oil and natural gas exploration and production outside North America.	550 WestLake Park Blvd. Suite 1000 Houston, Texas 77079 (281) 249-1040	**David M. Wood** President **Bruce R. Laws** Vice President, New Ventures **George M. Shirley** Vice President and General Manager – Malaysia **Steven A. Cossé** Vice President and General Counsel	**Kevin G. Fitzgerald** Treasurer **Dean E. Haefner** Controller **Walter K. Compton** 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	**W. Michael Hulse** 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 **Gordon W. Williamson** Treasurer **John W. Eckart** Controller **Walter K. Compton** Secretary
Murphy Eastern Oil Company Provides technical and professional services to certain of Murphy Oil Corporation's subsidiaries engaged in crude oil and natural gas exploration and production in the Eastern Hemisphere and 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** President **Ijaz Iqbal** Vice President, Treasury, Tax and Planning	**Kevin G. Fitzgerald** Treasurer **Walter K. Compton** Secretary

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 a.m. on May 10, 2006, 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:

Mindy K. West
Director of Investor Relations
Murphy Oil Corporation
P.O. Box 7000
El Dorado, Arkansas 71731-7000
(870) 864-6315

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, 2005. In 2005 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.

W. Michael Hulse
Executive Vice President – Worldwide Downstream Operations since April 2003 and President of Murphy Oil USA, Inc. since November 2001. Mr. Hulse served as President of Murphy Eastern Oil Company from April 1996 to November 2001.

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

Kevin G. Fitzgerald
Treasurer since July 2001. Mr. Fitzgerald was Director of Investor Relations from 1996 to June 2001.

John W. Eckart
Controller since March 2000.

Walter K. Compton
Secretary since December 1996.

MURPHY OIL CORPORATION

SUBSIDIARIES OF THE REGISTRANT AS OF DECEMBER 31, 2005

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. Mentor Insurance and Reinsurance Company	Louisiana	100.0
c. Mentor Insurance Limited	Bermuda	99.993
(1) Mentor Insurance Company (U.K.) Limited	England	100.0
(2) Mentor Underwriting Agents (U.K.) Limited	England	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 Ireland Offshore Limited	Bahamas	100.0
(2) Murphy Ecuador Oil Company Ltd.	Bermuda	100.0
(3) Murphy Peninsular Malaysia Oil Co., Ltd.	Bahamas	100.0
(4) Murphy Sabah Oil Co., Ltd.	Bahamas	100.0
(5) Murphy Sarawak Oil Co., Ltd.	Bahamas	100.0
b. El Dorado Exploration, S.A.	Delaware	100.0
c. Murphy Brazil Exploracao e Producao de Petroleo e Gas Ltda. (see company f.(1) below)	Brazil	90.0
d. Murphy Exploration (Alaska), Inc.	Delaware	100.0
e. Murphy Italy Oil Company	Delaware	100.0
f. Murphy Overseas Ventures Inc.	Delaware	100.0
(1) Murphy Brazil Exploracao e Producao de Petroleo e Gas Ltda. (see company c. above)	Brazil	10.0
g. Murphy Pakistan Oil Company	Delaware	100.0
h. Murphy Somali Oil Company	Delaware	100.0
i. Murphy-Spain Oil Company	Delaware	100.0
j. Murphy West Africa, Ltd.	Bahamas	100.0
k. Ocean Exploration Company	Delaware	100.0
l. 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

MURPHY OIL CORPORATION

SUBSIDIARIES OF THE REGISTRANT AS OF DECEMBER 31, 2005 (Contd.)

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
Murphy Oil Corporation (REGISTRANT) – Contd.		
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
4. Murphy Canada, Ltd.	Canada	100.0
5. Murphy Finance Company	NSULCo.*	100.0
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.

EXHIBIT 23

Consent of Independent Registered Public Accounting Firm

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, and 333-119733) on Form S-8 and (Nos. 33-55161 and 333-84547) on Form S-3 of Murphy Oil Corporation of our reports dated March 9, 2006, with respect to the consolidated balance sheets of Murphy Oil Corporation and Consolidated Subsidiaries as of December 31, 2005 and 2004, 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, 2005, and all related financial statement schedules, management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2005 and the effectiveness of internal control over financial reporting as of December 31, 2005, which reports appear in the December 31, 2005 annual report on Form 10-K of Murphy Oil Corporation. Our report refers to a change in the method of accounting for asset retirement obligations.

KPMG LLP

Houston, Texas
March 9, 2006

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/A 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 controls 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: March 16, 2006

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

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

I, Steven A. Cossé, certify that:

1. I have reviewed this annual report on Form 10-K/A 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 controls 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: March 16, 2006

/s/ Steven A. Cossé

Steven A. Cossé
Executive Vice President and General Counsel
(Principal Financial Officer)

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/A for the period ended December 31, 2005 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), we, Claiborne P. Deming and Steven A. Cossé, 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: March 16, 2006

/s/ Claiborne P. Deming

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

/s/ Steven A. Cossé

Steven A. Cossé
Executive Vice President and General Counsel
(Principal Financial Officer)

EXHIBIT 99.1

MURPHY OIL CORPORATION

STOCK OPTION

Stock Option Number:	Name of Optionee:	Number of Shares of Stock Subject to this Option:	Option Price Per Share:

This Stock Option granted on and dated ___________ __, 200__, by Murphy Oil Corporation, a Delaware corporation (the Company), pursuant to and for the purposes of the Stock Incentive Plan adopted by the stockholders of the Company on May 13, 1992, subject to the provisions set forth herein and in the Stock Incentive Plan. This Stock Option is designated a 'non-qualified' Stock Option under the Stock Incentive Plan.

1. The Company hereby grants to the individual named above (the Optionee) an option to purchase from the Company shares of the $1.00 par value Common Stock of the Company up to the maximum number and at the option price per shares set forth above.

2. Subject to paragraph 3 below, this option, two years after its date, if the Optionee has not died or terminated, shall become exercisable as to one-half of the shares optioned and, three years after its date, if he/she has still not died or terminated, shall become exercisable as to the remaining shares optioned: provided, however, this option shall not be exercisable whenever the purchase or delivery of shares under it would be a violation of any law or any governmental regulation which the Company may find to be valid and applicable.

3. Unless the Committee shall otherwise determine, this option shall become exercisable in full immediately upon a Change of Control as defined in the Stock Incentive Plan.

4. This option shall expire in the following situations:

(a) If the Optionee terminates normally, it shall expire two years thereafter if he/she is still living;

(b) If the Optionee terminates otherwise than normally, it shall expire at the time of termination;

(c) If the Optionee dies, it shall expire two years after his/her death;

(d) In any event, it shall expire seven years after its date.

5. This option is not assignable except as provided in the case of death and is not subject in whole or in part to attachment, execution or levy of any kind. If this option is exercisable after the Optionee dies, it is exercisable by his/her designated Beneficiary or, if there is no designated Beneficiary, by the executor or administrator of his/her estate.

6. When this option is exercisable as to any number of shares, it can be exercised for that number of shares or any lesser number to a minimum of 50 shares. Every share purchased through the exercise of this option shall be paid for in full at the time of purchase.

7. In the event of any relevant change in the capitalization of the Company subsequent to the date of this grant and prior to its exercise, the number of shares and purchase price will be adjusted to reflect that change.

8. This option shall be exercised in writing and in accordance with such administrative regulations or requirements as may be stipulated from time to time by the Executive Compensation Committee. Unless otherwise determined by the Committee, this option shall be settled by the Company's delivery to the individual of shares equating in value to the difference between (i) the fair market value of the shares at the time of exercise and (ii) the option price; less statutory withholding taxes. In case of the exercise of this option in full, it shall be surrendered to the Company for cancellation. In case of the exercise of this option in part, this option shall be delivered by the Optionee to the Company for the purpose of making appropriate notation thereon or of otherwise reflecting in such manner as the Company shall determine the result of such partial exercise of the option.

9. In this option

"Beneficiary" means the person designated by the optionee to the Company as the person entitled to exercise this option upon the death of the Optionee;

"Employer" means the Company or any subsidiary thereof by whom the Optionee is employed;

"Executive Compensation Committee" means the Executive Compensation Committee of the Board of Directors of the Company;

"Expire" means cease to be exercisable;

"Normal Termination" means terminate

(i) at normal retirement time,

(ii) for permanent and total disability, or

(iii) with employer approval and without being terminated for cause;

"Terminate" means cease to be an employee of the Company or a subsidiary except by death, but a change of employment from the Company or one subsidiary to another subsidiary or to the Company shall not be considered a termination. For this purpose, a subsidiary is any corporation of which the Company owns or controls, directly or indirectly, more than 50% of the stock possessing the right to vote for the election of directors.

Attest: **MURPHY OIL CORPORATION**

_______________________________ By: _______________________________

EXHIBIT 99.3

MURPHY OIL CORPORATION

STOCK OPTION

Stock Option Number:	Name of Optionee:	Number of Shares of Stock Subject to this Option:	Option Price Per Share:

This Stock Option granted on and dated ___________ __, 200_, by Murphy Oil Corporation, a Delaware corporation (the Company), pursuant to and for the purposes of the Stock Plan for Non-Employee Directors (the Plan) adopted by the stockholders of the Company on May 14, 2003, subject to the provisions set forth herein and in the Plan.

1. The Company hereby grants to the individual named above (the Optionee) an option to purchase from the Company shares of the $1.00 par value Common Stock of the Company up to the maximum number and at the option price per share set forth above.

2. Subject to paragraph 3 below and in accordance with the Plan, this option will become exercisable and mature in three equal annual installments commencing on the first anniversary of the date of grant and annually thereafter or in accordance with the Plan in the event of termination of Board Membership prior to the third anniversary of issuance. This option shall not be exercisable whenever the purchase or delivery of shares under it would be a violation of any applicable law, rule or regulation.

3. This option shall become exercisable in full immediately upon a Change in Control as defined by the Plan.

4. This option shall expire ten years from its date of issuance or sooner in the event of termination of Board Membership as described in the Plan.

5. In the event of any relevant change in the capitalization of the Company subsequent to the date of this grant and prior to its exercise, the number of shares and purchase price will be adjusted to reflect that change.

6. This option is not assignable except as provided in the case of death and is not subject in whole or in part to attachment, execution or levy of any kind. If this option is exercisable after the Optionee dies, it is exercisable by his/her designated beneficiary or, if there is no designated beneficiary, by the executor or administrator of his/her estate.

7. This option shall be exercised in writing and in accordance with such administrative regulations or requirements as may be stipulated from time to time by the Executive Compensation Committee Unless otherwise determined by the Committee, this option shall be settled by the Company’s delivery to the individual of shares equating in value to the difference between (i) the fair market value of the shares at the time of exercise and (ii) the option price; less statutory withholding taxes In case of the exercise of this option in full, it shall be surrendered to the Company for cancellation. In case of the exercise of this option in part, this option shall be delivered by the Optionee to the Company for purpose of making appropriate notation thereon or of otherwise reflecting in such manner as the Company shall determine the result of such partial exercise of the option.

Attest:	**MURPHY OIL CORPORATION**
______________________________	By ______________________________

March 16, 2006

United States Securities and Exchange Commission
Division of Corporate Finance
450 Fifth Street, NW
Washington, DC 20549

Gentlemen:

We are hereby electronically transmitting the 2005 Annual Report on Form 10-K/A, Commission File Number 1-8590, for Murphy Oil Corporation (Murphy) for the year ended December 31, 2005.

In 2005, the Company adopted SFAS No. 153, *Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29*; FIN 47, *Accounting for Conditional Asset Retirement Obligations*; FSP 109-1, *Accounting for Suspended Well Costs*; and EITF 03-13, *Applying the Conditions in Paragraph 42 of SFAS No. 144 in Determining Whether to Report Discontinued Operations.* Also, as discussed in Note G on Page F-14 on Form 10-K, Murphy adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, effective January 1, 2003.

If you have questions or require further information related to this filing, please call the undersigned at (870) 864-6290 or Keith Caldwell at (870) 864-6468.

Sincerely,

/s/ JOHN W. ECKART

John W. Eckart, Controller
Murphy Oil Corporation
CIK 0000717423