MURPHY OIL CORP /DE
Form 10-K
March 01, 2007
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2006

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ______ to ______

Commission file number 1-8590

MURPHY OIL CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**71-0361522**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**
200 Peach Street, P.O. Box 7000, El Dorado, Arkansas	**71731-7000**

(Address of principal executive offices)	(Zip Code)

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

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

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days. Yes x 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. x

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 x 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 x.

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on the last sale price at June 30, 2006 as quoted by the New York Stock Exchange, was approximately $10,436,919,000.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2007 was 187,637,200.

Documents incorporated by reference:

Portions of the Registrant s definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 9, 2007 have been incorporated by reference in Part III herein.

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MURPHY OIL CORPORATION

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PART I

Item 1. BUSINESS
Summary

Murphy Oil Corporation is a worldwide oil and gas exploration and production company with refining and marketing operations in 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 activities include interest income, interest expense, foreign exchange effects and overhead not allocated to the segments.

The information appearing in the 2006 Annual Report to Security Holders (2006 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 15 through 27, F-13 and F-14, F-31 through F-39, and F-41 of this Form 10-K report and on pages 6 and 7 of the 2006 Annual Report.

At December 31, 2006, Murphy had 7,296 employees, including 2,479 full-time and 4,817 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 2006, 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 2006 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. On November 15, 2006, the Company announced a reorganization to centralize its exploration and production management team in Houston, Texas in 2007, at which time Murphy Expro-USA s office in New Orleans, Louisiana will be closed.

Murphy s worldwide crude oil, condensate and natural gas liquids production in 2006 averaged 87,817 barrels per day, a decrease of 13% compared to 2005. The decrease was primarily due to lower production at the Terra Nova field, offshore Newfoundland, resulting from six months of downtime for major equipment maintenance during 2006. Oil production in the U.S. Gulf of Mexico was also lower in 2006 due to production declines at the Front Runner field in Green Canyon Blocks 338/339 and the Habanero field in Garden Banks Block 341. The Company s worldwide sales volume of natural gas averaged 75 million cubic feet (MMCF) per day in 2006, down 17% from 2005 levels. The lower natural gas sales were primarily attributable to sales volumes in 2005 from fields on the continental shelf of the Gulf of Mexico that were sold in mid-2005 and production declines in 2006 for fields in South Louisiana. Production commenced during 2006 in the Gulf of Mexico at the Seventeen Hands field in Mississippi Canyon Block 299, and this new production partially offset

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declines at other Gulf of Mexico fields, including the Tahoe field in Viosca Knoll Block 783 and the Front Runner and Habanero fields. Total worldwide 2006 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 100,361 barrels per day, down 14% compared to 2005.

Total production in 2007 is currently expected to average 95,000 to 105,000 barrels of oil equivalent per day. New production anticipated in the second half of 2007 from start-up of the Kikeh field in deepwater Block K, Malaysia, combined with a full year of production at the Terra Nova field after major maintenance downtime in 2006 and higher synthetic oil production due to a full year of production from a new coker unit that started up in 2006 at Syncrude are expected to be more than offset by lower production in the U.S. due to anticipated oil and natural gas volume declines at most fields in the Gulf of Mexico and onshore South Louisiana.

In the United States, Murphy has production of oil and/or natural gas from four fields operated by the Company and four main fields operated by others. Of the total producing fields at December 31, 2006, five are in the deepwater Gulf of Mexico, two 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 13 MMCF of gas per day net to the Company in 2006. Production from Medusa is expected to continue to decline in 2007 and should average 5,100 barrels of oil and 5 million cubic feet of natural gas on a daily basis. Murphy operates and holds a 37.5% interest in the Front Runner field in Green Canyon Blocks 338/339 with total net daily production in 2006 of about 5,000 barrels of oil and 4 MMCF of gas. Front Runner production in 2007 is expected to decline from 2006 levels, with daily averages anticipated of 2,900 barrels of oil and 2.7 million cubic feet of gas. The Company owns a 33.75% interest in the Habanero field in Garden Banks Block 341. Habanero, which is operated by Shell, produced about 2,400 barrels of oil per day and 3 MMCF of gas per day net to the Company in 2006. Habanero production is expected to average 1,300 barrels of oil per day and 2 MMCF per day in 2007, down from 2006 due to production decline on existing wells. Potential drilling in 2007 could partially mitigate production declines at Habanero. The Company has a 37.5% interest in the Seventeen Hands field in Mississippi Canyon Block 299. This field, operated by Dominion, began production in March 2006, but was off production for most of the fourth quarter due to a subsea valve failure. Daily net production at Seventeen Hands averaged about 9 MMCF of gas per day for the full year of 2006. Seventeen Hands production is expected to be 8 MMCF per day in 2007. The other deepwater producing field is Tahoe in Viosca Knoll Block 783, in which the Company has a 30% interest. Tahoe is operated by Shell and in 2006 produced about 4 MMCF of natural gas per day and 100 barrels of oil per day net to the Company. Production in 2006 at Tahoe was adversely affected by a full-year shut in of two wells that require workovers. Tahoe production is anticipated to average slightly more than 2 MMCF per day in 2007. The Tahoe field owners are considering operations in 2007 to bring additional wells on production. In 2004 Murphy announced a discovery at the Thunder Hawk field in Mississippi Canyon Block 734 and in mid-2006 announced a discovery at Thunder Bird in Mississippi Canyon Block 819. Murphy operates both fields. Murphy sanctioned development of 37.5% owned Thunder Hawk during 2006 and first production is anticipated in mid-2009. The Company is presently evaluating development options for Thunder Bird. In 2005 the Company announced a discovery at the Mondo NW field in Lloyd Ridge Blocks 1 and 2. Natural gas production from the 50% owned Mondo NW, operated by Anadarko, is expected in late 2007. Murphy holds an interest in 218 blocks in the deepwater Gulf of Mexico and continues to evaluate prospects for future exploratory drilling locations. Onshore production, which is mostly natural gas, is primarily located on several leases in Vermilion Parish, Louisiana. Murphy s net production in 2006 from onshore fields was 21 MMCF per day, but 2007 production is anticipated to be 14 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 600 barrels per day in 2006. Northstar volumes in 2007 are anticipated to decline slightly. Murphy is conducting an onshore U.S. exploration program searching for unconventional shale gas, but results have been unsuccessful thus far. We are currently participating at a 50% interest in a 2007 drilling program in this onshore area.

In Canada, the Company owns an interest in three significant, long-lived assets, the Hibernia and Terra Nova fields offshore Newfoundland and Syncrude Canada Ltd. in northern Alberta. In addition, the Company owns interests in two significant heavy oil areas and one significant natural gas area in the Western Canadian Sedimentary Basin (WCSB). Murphy has a 6.5% interest in Hibernia and a 12% interest in Terra Nova, with these being the first two fields on production in the Jeanne d Arc Basin, offshore Newfoundland. Total net production in 2006 was about 11,000 barrels of oil per day at Hibernia, which is operated by Hibernia Management and Development Company, while net production from Terra Nova, which is operated by PetroCanada, was about 3,900 barrels of oil per day. Terra Nova was shut down for major equipment maintenance for approximately six months in 2006. The field came back on production in mid-November. Total 2007 net production at Hibernia and Terra Nova is anticipated to be approximately 8,800 and 8,900 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 completed an expansion in 2006 by adding a third coker that allows for increased production. Total net production in 2006 was about 11,700 barrels of synthetic crude oil per day, but due to the expansion net production is expected to average about 14,100 barrels per day in 2007. Although Syncrude produces a very high quality synthetic crude oil from bitumen, the U.S. Securities and Exchange Commission (SEC) considers Syncrude to be a mining operation, and not a conventional oil operation and therefore, does not allow the Company to include Syncrude s reserves in its proved oil reserves reported on page F-35. Production in 2006 in the WCSB averaged about 13,000 barrels per day of mostly heavy oil and about 10 MMCF of natural gas per day. WCSB oil production in 2007 is expected to be similar to 2006 volumes. Canadian natural gas production levels in 2007 should increase from 2006 levels due to the acquisition in late 2006 of Berkana Energy Corp. In December, Murphy acquired 80% of Rosetta Exploration Inc. through a reverse acquisition. Murphy contributed its working interest in the Rimbey field in Central Alberta for its interest in Rosetta, which then changed its name to Berkana Energy Corp. Murphy s consolidated financial statements include the accounts of Berkana Energy subsequent to the acquisition. Shares of Berkana Energy are traded on the Toronto Venture Exchange under the ticker symbol BEC .

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 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 3,600 net barrels of oil per day in 2006. 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 2006, the Mungo and Monan fields produced approximately 3,500 barrels of oil per day, net to Murphy s interest. Total U.K. natural gas sales averaged about 9 MMCF per day in 2006 from production primarily at the Amethyst gas field in the North Sea and the Mungo/Monan fields. Oil and natural gas production in the U.K. in 2007 is expected to decline slightly compared to 2006 volumes.

In Ecuador, Murphy owns a 20% working interest in Block 16, which is operated by Repsol YPF under a participation contract that expires in early 2012. The Company s net production was about 8,600 barrels of oil per day in 2006 and is expected to average about 8,200 barrels per day in 2007. 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 two nonoperator partners in 2006 and recouped about 853,000 barrels of oil associated with the 2004 shortfall. Murphy had previously settled a 663,000 barrel shortfall with the operator in 2005.

In Malaysia, the Company has majority interests in nine separate production sharing contracts (PSCs). The Company serves as the operator of all these areas, which cover approximately 12.3 million acres. Murphy had an 85% interest in two shallow water blocks, SK 309 and SK 311, through 2006. In February 2007, the Company renewed the contract on these two Sarawak blocks at a 60% interest for areas with no discoveries. The Company retained an 85% interest in the portion of these blocks on which discoveries have been made. The West Patricia and Congkak fields in Block SK 309 produced about 11,300 net barrels of oil per day in 2006. Net production in 2007 is anticipated to decline at these fields to about 9,600 barrels of oil per day due to a lower percentage of production allocable to the Company under the production sharing contract. The Company has also made several natural gas discoveries in these shallow water blocks. In February 2007, the Company finalized a gas sales contract for the Sarawak area with PETRONAS, the Malaysian state-owned oil company, with initial gas deliveries anticipated in the first half of 2009. The Company made a major discovery at the Kikeh field in deepwater Block K, offshore Sabah, in 2002 and added another important discovery at Kakap in 2004. Further discoveries have been made in Block K at Senangin and Kerisi. In 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. First oil production from Kikeh is expected in the second half of 2007. Production volumes are expected to increase at Kikeh throughout 2008 as additional wells are completed and brought on line. The Company has booked proved oil reserves of 47.5 million barrels related to the Kikeh field. 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. In February 2007, the Company signed a Kikeh field natural gas sales contract with PETRONAS. In 2006, the Company relinquished a portion of Block K and was granted a 60% interest in an extension of a portion of Block K covering 1.02 million acres. The Company retained its 80% interest in the Kikeh and Kakap discoveries in Block K. In early 2006, the Company also added a 60% interest in a new PSC for Block P, which includes 1.05 million acres of the previously relinquished Block K area. Murphy drilled an unsuccessful wildcat well in Block P during 2006. 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 and 2006. The Company has an 80% interest in deepwater Block H offshore Sabah, and it drilled an unsuccessful wildcat well on this block in 2006. In early 2007, the Company announced a

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significant natural gas discovery at the Rotan well in Block H. The Company was awarded interests in two PSCs covering deepwater Blocks L (60%) and M (70%) in 2003. The Sultanate of Brunei also claims this acreage. Murphy drilled a wildcat well in Block L in mid-2003. Well results have been kept confidential and well costs of $12 million remain capitalized pending the resolution of the ownership issue. The Company is unable to predict when or how ownership of Blocks L and M will be resolved. A total of 2.9 million gross acres associated with Blocks L and M have been included in the acreage table below.

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 the southern block, MPS. In 2005, the Company successfully followed up the Azurite discovery with an appraisal well that tested at 8,000 barrels of oil per day from one zone. A third well in early 2006 further appraised the Azurite area. The Company drilled four unsuccessful exploratory wells on other parts of the MPS block in 2005. During 2006, the Company s efforts in the Republic of the Congo were primarily directed toward preparation of a plan of development for the Azurite field discovery. The Company s Board of Directors approved the development of the Azurite field in late 2006.

Murphy s estimated net quantities of proved oil and gas reserves and proved developed oil and gas reserves at December 31, 2003, 2004, 2005 and 2006 by geographic area are reported on pages F-35 and F-36 of this Form 10-K report. Murphy has not filed and is not required to file any estimates of its total net proved oil or gas reserves on a recurring basis with any federal or foreign governmental regulatory authority or agency other than the U.S. Securities and Exchange Commission. Annually, Murphy reports gross reserves of properties operated in the United States to the U.S. Department of Energy; such reserves are derived from the same data from which estimated net proved reserves of such properties are determined.

Net crude oil, condensate and gas liquids production and sales, and net natural gas sales by geographic area with weighted average sales prices for each of the seven years ended December 31, 2006 are shown on page 6 of the 2006 Annual Report. In 2006, 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 21 of this Form 10-K report. For purposes of these computations, natural gas sales volumes are converted to equivalent barrels of crude oil using a ratio of six thousand cubic feet (MCF) of natural gas to one barrel of crude oil.

Supplemental disclosures relating to oil and gas producing activities are reported on pages F-34 through F-41 of this Form 10-K report.

At December 31, 2006, Murphy held leases, concessions, contracts or permits on developed and undeveloped acreage as shown by geographic area in the following table. Gross acres are those in which all or part of the working interest is owned by Murphy. Net acres are the portions of the gross acres attributable to Murphy s interest.

	Developed		Undeveloped		Total	
Area (Thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States Onshore	5	3	626	281	631	284
Gulf of Mexico	17	6	1,304	841	1,321	847
Alaska	3	1	4		7	1
Total United States	25	10	1,934	1,122	1,959	1,132
Canada Onshore	87	53	455	353	542	406
Offshore	88	8	8,306	2,576	8,394	2,584
Total Canada	175	61	8,761	2,929	8,936	2,990
United Kingdom	33	4	40	6	73	10
Ecuador	7	1	524	105	531	106
Malaysia	3	2	12,299	8,997	12,302	8,999
Republic of Congo			1,773	1,507	1,773	1,507
Spain			36	6	36	6

Totals		243	78	25,367	14,672	25,610	14,750
Oil sands	Syncrude	96	5	158	8	254	13

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The Company s net acreage position in Malaysia in the preceding table was reduced in February 2007 by 472,000 acres due to contract renewals on Blocks SK 309 and SK 311 at a 60% interest for exploration areas. The Company retained its 85% interest on acreage where oil and natural gas has previously been discovered. Other significant undeveloped acreage that expires in the next three years consists of approximately 3.6 million net acres in Malaysia and 1.0 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, 2006.

	Oil Wells		Gas Wells	
Country	**Gross**	**Net**	**Gross**	**Net**
United States	36	7	14	6
Canada	482	337	82	61
United Kingdom	32	3	22	2
Malaysia	16	14		
Ecuador	143	29		
Totals	709	390	118	69

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**
2006												
Exploratory	0.8	1.4					11.8	3.4	1.0	0.2	13.6	5.0
Development			61.5	24.8	0.1		2.4		5.2		69.2	24.8
2005												
Exploratory	1.5	2.2				0.5	10.2	5.0	2.0	4.2	13.7	11.9
Development	0.9		87.0	8.0	0.1				4.0		92.0	8.0
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

Murphy s drilling wells in progress at December 31, 2006 are shown below.

	Exploratory		Development		Total	
Country	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States	1.0	.01	1.0	.38	2.0	.39
Canada	2.0	.32	5.0	2.20	7.0	2.52
United Kingdom			2.0	.12	2.0	.12
Ecuador			4.0	.80	4.0	.80
Totals	3.0	.33	12.0	3.50	15.0	3.83

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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 larger of its U.S. refineries is at Meraux, Louisiana, on the Mississippi River approximately 10 miles southeast of New Orleans. The refinery is located on fee land 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 Company s refinery at Superior, Wisconsin is located on fee land. Murco Petroleum Limited (Murco), a wholly owned U.K. subsidiary, has an effective 30% interest in a refinery at Milford Haven, Wales that can process 108,000 barrels of crude oil per day.

Refinery capacities at December 31, 2006 are shown in the following table.

	Meraux, Louisiana	Superior, Wisconsin	Milford Haven Wales (Murco s 30%)	Total
Crude capacity b/sd*	125,000	35,000	32,400	192,400
Process capacity b/sd*				
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	10,500	5,490	50,990
Catalytic reforming	32,000	8,000	5,490	45,490
Gasoline hydrotreating		7,500		7,500
Distillate hydrotreating	52,000	11,800	20,250	84,050
Hydrocracking	32,000			32,000
Gas oil hydrotreating	12,000			12,000
Solvent deasphalting	18,000			18,000
Isomerization			3,400	3,400
Production capacity b/sd*				
Alkylation	8,500	1,500	1,680	11,680
Asphalt		7,500		7,500
Crude oil and product storage capacity barrels	4,056,000	3,085,000	2,638,000	9,779,000

* Barrels per stream day.

In late August 2005, the Meraux, Louisiana refinery was severely damaged by flooding and high winds caused by Hurricane Katrina. The Meraux refinery was shut-down for repairs for about nine months following the hurricane and restarted in mid-2006. The majority of costs to repair the Meraux refinery are expected to be covered by insurance. Oil Insurance Limited (O.I.L.), the Company s primary property insurance coverage, has informed insureds that it has currently estimated that recoveries for Hurricane Katrina damages will likely be no more than 48% of claimants eligible losses. Murphy has other commercial insurance coverage for repair costs not covered by O.I.L., but this coverage limits recoveries from flood damage to $50.0 million. Costs to repair the refinery were approximately $196 million. Based on the expected insurance recoveries and repair costs as described, the Company has recorded repair costs not recoverable from insurance of $50.7 million in 2006. The final settlement and recovery of insurance could take several years to complete. At December 31, 2006, total receivables from insurance companies related to hurricane repairs at Meraux was $72.8 million.

In 2003, Murphy 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 refinery had no solvent deasphalting processing capability during 2004 and early 2005 because of a fire in June 2003 that destroyed the Residual Oil Supercritical Extractor (ROSE) unit. The ROSE unit was 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 the addition of a fluid catalytic cracking gasoline hydrotreater unit at its Superior, Wisconsin refinery, that allows the refinery to meet low-sulfur gasoline specifications. In 2006, the isomerization unit at the Superior refinery was revamped to a hydrotreater and one of two existing naptha hydrotreaters was revamped to a kerosine hydrotreater.

MOUSA markets refined products through a network of retail gasoline stations and branded and unbranded wholesale customers in a 23-state area of the southern and midwestern United States. Murphy s retail stations are primarily located in the parking lots of Wal-Mart Supercenters in 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 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. At December 31, 2006, the Company marketed products through 987 Murphy stations and 169 branded wholesale SPUR stations. MOUSA plans to build additional retail gasoline stations, primarily at Wal-Mart Supercenters in 2007. 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 represented 51.7% of consolidated Company revenues in 2006, 44.6% in 2005 and 38.6% in 2004. 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.

Murphy owns a 20% interest in a 120-mile refined products pipeline, with a capacity of 165,000 barrels per day, that transports products from the Meraux refinery to two common carrier pipelines serving the southeastern United States. The Company also owns a 3.2% interest in the Louisiana Offshore Oil Port LLC (LOOP), which provides deepwater unloading accommodations off the Louisiana coast for oil tankers and onshore facilities for storage of crude oil. A crude oil pipeline with a diameter of 24 inches connects LOOP storage at Clovelly, Louisiana to the Meraux refinery. In December 2006, Murphy acquired an additional 10.7% interest in the first 22 miles of this pipeline from Clovelly to Alliance, Louisiana, thereby raising its ownership interest to 40.1%; the Company owns 100% of the remaining 24 miles from Alliance to Meraux. This crude oil pipeline is connected to another company s pipeline system, allowing crude oil transported by that system to also be shipped to the Meraux refinery.

In 2006, Murphy owned approximately 1.0% of the crude oil refining capacity in the United States and its market share of U.S. retail gasoline sales was approximately 2.3%.

At the end of 2006, 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 402 branded stations primarily under the brand name MURCO. During 2005, Murco purchased 68 existing retail fueling stations.

A statistical summary of key operating and financial indicators for each of the seven years ended December 31, 2006 are reported on page 7 of the 2006 Annual Report.

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Item 1A. RISK FACTORS
Competition

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

Reserve Replacement

Murphy continually depletes its oil and natural reserves as production occurs. In order to sustain and grow its business, the Company must successfully replace the crude oil and natural gas it produces with additional reserves. Therefore, it must create and maintain a portfolio of good prospects for future reserve additions and production by obtaining rights to explore for, develop and produce hydrocarbons in promising areas. In addition, it must find, develop and produce and/or purchase reserves found at a competitive cost structure to be successful in the long-term. Murphy s ability to operate profitably in the exploration and production segments of its business, therefore, is dependent on its ability to find, develop and produce and/or purchase oil and natural gas reserves at costs that are less than the realized sales price for these products and at costs competitive with competing companies in the industry.

Proved Reserves

Proved crude oil and natural gas reserves included in this report on pages F-35 and F-36 have been prepared by Company personnel and outside experts based on oil and natural gas prices in effect at the end of each year as well as other conditions and information available at the time the estimates were prepared. Estimation of reserves is a subjective process that involves professional judgment by engineers about volumes to be recovered in future periods from underground crude oil and natural gas reservoirs. Estimates of economically recoverable crude oil and natural gas reserves and future net cash flows depend upon a number of variable factors and assumptions, and consequently, different engineers could arrive at different estimates of reserves and future net cash flows based on the same available data and using industry accepted engineering practices and scientific methods.

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

The discounted future net revenues from our proved reserves should not be considered as the market value of the reserves attributable to our properties. As required by generally accepted accounting principles, the estimated discounted future net revenues from our proved reserves are based generally on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. In addition, the 10 percent discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under generally accepted accounting principles is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the crude oil and natural gas business in general.

Price Volatility

The most significant variables affecting the Company s results of operations are the sales prices for crude oil, natural gas and refined products that it produces. The Company s income in 2006 was favorably affected by high crude oil and natural gas prices; if these prices decline significantly in 2007 or future years, the Company s results of operations would be negatively impacted. In addition, the Company s net income could be adversely affected by lower future refining and marketing margins. Except in limited cases, the Company typically does not seek to hedge any significant portion of its exposure to the effects of changing prices of crude oil, natural gas and refined products. Certain of the Company s crude oil production is heavy and more sour than West Texas Intermediate (WTI) quality crude; therefore, this crude oil usually sells at a discount to WTI and other light and sweet crude oils. In addition, the sales prices for heavy and sour crude oils do not always move in relation to price changes for WTI and lighter/sweeter crude oils.

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Dry Hole Exposure

The Company generally drills numerous wildcat wells each year which subjects its upstream operating results to significant exposure to dry holes expense, which have adverse effects on, and create volatility for, the Company s overall net income. In 2006, significant wildcat wells were primarily drilled offshore Malaysia and in the U.S. Gulf of Mexico. The Company s 2007 budget calls for wildcat drilling primarily in the Gulf of Mexico, offshore Malaysia and the Republic of Congo.

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 based on foreseeable financing needs. Although not considered likely, there is the possibility that financing arrangements may not always be available at sufficient levels required to fund the Company s development activities.

Limited Control

The ability of the Company to successfully manage development and operating costs is important because virtually all of the products it sells are energy commodities such as crude oil, natural gas and refined products, for which the Company has little or no influence on the sales prices or regional and worldwide consumer demand for these products. Murphy is a net purchaser of crude oil and other refinery feedstocks, and also purchases refined products, particularly gasoline, needed to supply its retail marketing stations 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 crude oil, natural gas and refined product prices such as those experienced in 2006 and 2005 because an increase in exploration and production activities due to high oil and gas sales prices generally leads to higher demand for, and consequently higher costs for, goods and services in the oil and gas industry.

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.

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, 2006, approximately 46% of proved reserves, as defined by the U.S. Securities and Exchange Commission, were located in countries other than the U.S., Canada and the U.K. Certain of the reserves held outside these three countries could be considered to have more political risk. In addition, prices and availability of crude oil, natural gas and refined products could be influenced by political unrest and by various governmental policies to restrict or increase petroleum usage and supply. Other governmental actions that could affect Murphy s operations and earnings include tax changes, royalty increases and regulations concerning: currency fluctuations, protection and remediation of the environment (See the caption Environmental beginning on page 27 of this Form 10-K report), preferential and discriminatory awarding of oil and gas leases, restrictions on drilling and/or production, restraints and controls on imports and exports, safety, and relationships between employers and employees. Because these and other factors too numerous to list are subject to changes caused by governmental and political considerations and are often made in response to changing internal and worldwide economic conditions and to actions of other governments or specific events, it is not practical to attempt to predict the effects of such factors on Murphy s future operations and earnings.

Industry and Other Risks

Murphy s business is subject to operational hazards and risks normally associated with the exploration for and production of oil and natural gas and the refining and marketing of crude oil and petroleum products. The Company operates in urban and remote, and often inhospitable, areas around the world. The occurrence of an event, including but not limited to acts of nature such as hurricanes, floods, earthquakes and other forms of severe weather, and mechanical equipment failures, industrial accidents, fires, explosions, acts of war and intentional terrorist attacks could result in the loss of hydrocarbons and associated revenues, environmental pollution or contamination, and personal injury, including death, for which the Company could be deemed to be liable, and which could subject the Company to substantial fines and/or claims for punitive damages.

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The location of many of Murphy s key assets causes the Company to be vulnerable to severe weather, including hurricanes and tropical storms. A number of significant oil and natural gas fields lie in offshore waters around the world. Probably the most vulnerable of the Company s offshore fields are in the U.S. Gulf of Mexico, where severe hurricanes and tropical storms have often led to shutdowns and damages. The U.S. hurricane season runs from June through November, but the most severe storm activities usually occur in late summer, such as with Hurricanes Katrina and Rita in 2005. Additionally, the Company s largest refinery is located about 10 miles southeast of New Orleans, Louisiana. In August 2005, Hurricane Katrina passed near the refinery causing major flooding and severe wind damage. The gradual loss of coastal wetlands in southeast Louisiana increases the risk of future flooding should storms such as Katrina recur in the future. Other assets such as gasoline terminals and certain retail gasoline stations also lie near the Gulf of Mexico coastlines and are vulnerable to storm damages. During the repairs at Meraux following Hurricane Katrina, the refinery took steps to try to reduce the potential for damages from future storms of similar magnitude. For example, certain key equipment such as motors and pumps were raised above ground level when feasible. These steps may somewhat reduce the damages associated with windstorm and major flooding that could occur with a future storm similar in strength to Katrina, but the risks from such a storm are not eliminated. Although the Company also maintains insurance for such risks as described below, due to policy deductibles and possible coverage limits, weather-related risks are not fully insured.

Insurance

Murphy maintains insurance against certain, but not all, hazards that could arise from its operations, and such insurance is believed to be reasonable for the hazards and risks faced by the Company. As of December 31, 2006, the Company maintained total excess liability insurance with limits of $750 million per occurrence covering certain general liability and certain sudden and accidental environmental risks. The Company also maintained insurance coverage with an additional limit of $250 million per occurrence, all or part of which could be applicable to certain sudden and accidental pollution events. There can be no assurance that such insurance will be adequate to offset costs associated with certain events or that insurance coverage will continue to be available in the future on terms that justify its purchase. The occurrence of an event that is not fully insured could have a material adverse effect on the Company s financial condition and results of operations in the future. During 2005, damages from hurricanes caused shut-down of certain U.S. oil and gas production operations as well as the Meraux, Louisiana refinery. The Company repaired the Meraux refinery and it restarted operations in mid-2006. The Company does not expect to fully recover repair costs incurred at Meraux under its insurance policies. See Note O in the consolidated financial statements for further discussion.

Litigation

The Company is involved in numerous lawsuits seeking cash settlements for alleged personal injuries, property damages and other business-related matters. The most significant of these matters are addressed in more detail in Item 3 beginning on page 11 of this Form 10-K report.

Credit Exposure

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

Retirement Plans

A number of actuarial assumptions impact funding requirements for the Company s retirement plans. The most significant of these assumptions include return on assets, long-term interest rates and mortality. If the actual results for the plans vary significantly from the actuarial assumptions used, or if laws regulating such retirement plans are changed, Murphy could be required to make significant funding payments to one or more of its retirement plans in the future and/or it could be required to record a larger liability for future obligations in its Consolidated Balance Sheet.

Item 1B. UNRESOLVED STAFF COMMENTS

The Company had no unresolved comments from the staff of the U.S. Securities and Exchange Commission as of December 31, 2006.

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Item 2. PROPERTIES

Descriptions of the Company s oil and natural gas and refining and marketing properties are included in Item 1 of this Form 10-K report beginning on page 1. Information required by the Securities Exchange Act Industry Guide No. 2 can be found in the Supplemental Oil and Gas Information section of this Annual Report on Form 10-K on pages F-34 to F-41 and in Note D Property, Plant and Equipment on page F-13.

Executive Officers of the Registrant

The age at January 1, 2007, 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 52; President and Chief Executive Officer since October 1994 and Director and Member of the Executive Committee since 1993.

Steven A. Cossé Age 59; Executive Vice President since February 2005 and General Counsel since August 1991. Mr. Cossé was elected Senior Vice President in 1994 and Vice President in 1993.

Harvey Doerr Age 48; Executive Vice President responsible for the Company s worldwide refining and marketing operations and strategic planning effective January 1, 2007. Mr. Doerr served as President of Murphy Oil Company Ltd. from September 1997 through December 2006.

David M. Wood Age 49; Executive Vice President responsible for the Company s worldwide exploration and production operations effective January 1, 2007. Mr. Wood served as President of Murphy Exploration & Production Company-International from March 2003 through December 2006 and was Senior Vice President of Frontier Exploration & Production from April 1999 through February 2003.

Kevin G. Fitzgerald Age 51; Senior Vice President and Chief Financial Officer since January 1, 2007. He served as Treasurer from July 2001 through December 2006 and was Director of Investor Relations from 1996 through June 2001.

Bill H. Stobaugh Age 55; Senior Vice President since February 2005. Mr. Stobaugh joined the Company as Vice President in 1995.

Mindy K. West Age 37; Vice President and Treasurer since January 1, 2007. Ms. West was Director of Investor Relations from July 2001 through December 2006.

John W. Eckart Age 48; Vice President and Controller since January 1, 2007. Mr. Eckart served as Controller since March 2000.

Walter K. Compton Age 44; Secretary since December 1996.

Item 3. LEGAL PROCEEDINGS

On September 9, 2005, a class action lawsuit was filed in federal court in the Eastern District of Louisiana seeking unspecified damages to the class comprised of residents of St. Bernard Parish caused by a release of crude oil at Murphy Oil USA, Inc. s (a wholly-owned subsidiary of Murphy Oil Corporation) Meraux, Louisiana, refinery as a result of flood damage to a crude oil storage tank following Hurricane Katrina. Additional class action lawsuits were consolidated with the first suit into a single action in the U.S. District Court for the Eastern District of Louisiana. In September 2006, the Company reached a settlement with class counsel and on October 10, 2006, the court granted preliminary approval of a class action Settlement Agreement. A Fairness Hearing was held January 4, 2007 and the court entered its ruling on January 30, 2007 approving the class settlement. The majority of the settlement of $330 million will be paid by insurance. The Company recorded an expense of $18 million in 2006 related to settlement costs not expected to be covered by insurance. As part of the settlement, all properties in the class area will receive a fair and equitable cash payment and will have residual oil cleaned. As part of the settlement, the Company will offer to purchase all properties in an agreed area adjacent to the west side of the Meraux refinery; these property purchases and associated remediation will be paid by the Company and are expected to total $55 million. Approximately 100 non-class action suits regarding the oil spill have been filed and remain pending; however, as part of its October 10, 2006, order, the court stayed these actions pending the

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settlement proceedings and further orders of the court. The Company believes that insurance coverage exists and it does not expect to incur significant costs associated with this litigation. Accordingly, the Company believes the ultimate resolution of the remaining litigation 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. The St. Bernard Parish action has since been removed to federal court where a class certification hearing is scheduled for June 24, 2007. 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 alleged 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. A trial concerning the 25% disputed interest and any remaining issues was held in the second quarter 2006 and on September 15, 2006 the Court of Queen s Bench of Alberta issued a ruling in the Company s favor. Predator did not appeal. Based on this ruling, approximately $15.9 million of previously disputed natural gas sales proceeds and associated interest was recognized as income during the fourth quarter 2006.

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 2006.

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PART II

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

The Company s Common Stock is traded on the New York Stock Exchange using MUR as the trading symbol. There were 2,758 stockholders of record as of December 31, 2006. Information as to high and low market prices per share and dividends per share by quarter for 2006 and 2005 are reported on page F-42 of this Form 10-K report.

SHAREHOLDER RETURN PERFORMANCE PRESENTATION

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

	2001	2002	2003	2004	2005	2006
Murphy Oil Corporation	100	104	161	201	272	259
S&P 500 Index	100	78	100	111	117	135
AMEX Oil Index	100	88	115	151	211	260

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Item 6. SELECTED FINANCIAL DATA

(Thousands of dollars except per share data)	2006	2005	2004	2003	2002
Results of Operations for the Year					
Sales and other operating revenues	$ 14,279,325	11,680,079	8,299,147	5,094,518	3,779,381
Net cash provided by continuing operations	962,702	1,216,713	1,035,057	501,127	372,205
Income from continuing operations	638,279	837,903	496,395	278,410	87,279
Net income	638,279	846,452	701,315	294,197	111,508
Per Common share diluted					
Income from continuing operations	3.37	4.46	2.65	1.50	.47
Net income	3.37	4.51	3.75	1.59	.61
Cash dividends per Common share	.525	.45	.425	.40	.3875
Percentage return on					
Average stockholders equity	16.8	28.3	31.3	16.4	7.3
Average borrowed and invested capital	14.4	23.6	21.8	11.0	5.8
Average total assets	9.1	14.5	13.5	6.7	3.9
Capital Expenditures for the Year					
Continuing operations					
Exploration and production	$ 1,082,756	1,091,954	839,182	689,632	538,994
Refining and marketing	173,400	202,401	134,706	215,362	234,714
Corporate and other	6,383	35,476	1,505	1,120	1,136
	1,262,539	1,329,831	975,393	906,114	774,844
Discontinued operations			9,065	73,050	93,256
	$ 1,262,539	1,329,831	984,458	979,164	868,100
Financial Condition at December 31					
Current ratio	1.61	1.43	1.35	1.28	1.19
Working capital	$ 795,986	551,938	424,372	228,529	136,268
Net property, plant and equipment	5,106,282	4,374,229	3,685,594	3,530,800	2,886,599
Total assets	7,445,727	6,368,511	5,458,243	4,712,647	3,885,775
Long-term debt	840,275	609,574	613,355	1,090,307	862,808
Stockholders equity	4,052,676	3,460,990	2,649,156	1,950,883	1,593,553
Per share	21.61	18.61	14.39	10.62	8.69
Long-term debt percent of capital employed	17.2	15.0	18.8	35.9	35.1

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

Overview

Murphy Oil Corporation is a worldwide oil and gas exploration and production company with 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 refining and marketing operations are dependent upon achieving adequate margins, which are determined by the sales prices for refined petroleum products less the costs of purchased refinery feedstocks and gasoline and expenses associated with manufacturing, transporting and marketing these products. Murphy also incurs certain costs for general company administration and for capital borrowed from lending institutions.

Worldwide oil prices were generally higher in 2006 than in 2005, while the average sales price for North American natural gas was lower in 2006 than 2005. The average price for a barrel of West Texas Intermediate crude oil in 2006 was $66.00, an increase of 16% compared to 2005. The NYMEX natural gas price in 2006 averaged $6.74 per million British Thermal Units (MMBTU), down 25% from 2005. Changes in the price of crude oil and natural gas have a significant impact on the profitability of the Company, especially the price of crude oil as oil represented approximately 88% of the total hydrocarbons produced on an energy equivalent basis by the Company in 2006. If the prices for crude oil and natural gas decline significantly in 2007 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 2006 of $638.3 million, $3.37 per diluted share, compared to net income in 2005 of $846.5 million, $4.51 per diluted share. In 2004 the Company s net income was $701.3 million, $3.75 per diluted share. The net income reduction in 2006 compared to 2005 primarily related to lower earnings generated by the Company s exploration and production and refining and marketing businesses. In addition, the net cost of corporate activities was higher in 2006 than in 2005. 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 activities. Further explanations of each of these variances are found in the following sections.

Income from continuing operations was $638.3 million, $3.37 per diluted share, in 2006, $837.9 million, $4.46 per diluted share, in 2005, and $496.4 million, $2.65 per diluted share, in 2004.

Income from discontinued operations was $8.6 million, $0.05 per diluted share, in 2005, and $204.9 million, $1.10 per diluted share, in 2004. There was no impact from discontinued operations in 2006. In the second quarter 2004 the Company sold most of its conventional oil and natural gas properties in western Canada for cash proceeds of $583 million, which generated an after-tax gain on the sale of $171.1 million in 2004. 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 years ended December 31, 2005 and 2004. Income from discontinued operations in 2005 related to a favorable adjustment of income taxes associated with the gain on sale of the western Canada properties in 2004.

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2006 vs. 2005 Net income in 2006 was $638.3 million, $3.37 per diluted share, compared to $846.5 million, $4.51 per diluted share, in 2005. Net income in 2005 included income from discontinued operations of $8.6 million, which was $0.05 per share. The $208.2 million decline in net income in 2006 was primarily due to lower earnings in both the Company s exploration and production (E&P) and refining and marketing (R&M or Downstream) businesses, plus higher net costs for corporate activities. The Company s E&P earnings declined in 2006 due to several factors in the current year, including lower sales volumes for crude oil and natural gas caused by lower production levels for these products, lower natural gas sales prices in North America and higher production and administrative expenses. In addition, in 2005 the Company recorded an after-tax gain of $104.5 million related to a sale of most mature oil and natural gas properties on the continental shelf of the Gulf of Mexico. The 2006 E&P results were favorably impacted by higher crude oil sales prices, lower after-tax exploration expenses, lower hurricane-related costs and higher income tax benefits due to various tax rate changes. Company-wide, the net costs associated with hurricanes were $42.5 million higher in 2006 compared to 2005. Hurricane costs in the Company s R&M business were $59.8 million higher in 2006 due to more uninsured costs associated with repairs at the Meraux, Louisiana refinery, clean-up of a crude oil spill that occurred at the refinery as a result of damages from Hurricane Katrina, and settlement of litigation associated with the oil spill. Hurricane costs in the Company s E&P business were lower in 2006 by $16.9 million due to lower costs in the current year for equipment and facilities repair, discretionary employee assistance and hurricane-related insurance in the current year. Earnings in the R&M business were $105.1 million in 2006 compared to $125.3 million in 2005. This earnings reduction of $20.2 million in 2006 was primarily caused by the aforementioned higher hurricane-related costs. Excluding the higher hurricane costs, U.S. downstream earnings improved in 2006 compared to 2005, while 2006 earnings for downstream operations in the U.K. were down $8.1 million from record levels in 2005. The Company continued to expand its retail gasoline station business by adding 123 sites in 2006, with virtually all such additions located at Wal-Mart Supercenters. The net costs of corporate activities were $82.7 million in 2006 compared to $35.5 million in 2005. These costs increased mostly due to an educational assistance contribution commitment amounting to $25.1 million after-tax, plus the unfavorable effects of foreign currency exchange movements as the U.S. dollar weakened against most other major currencies used by Company s operations, including the Euro and the U.K. pound sterling. In addition, corporate activity costs in 2006 were unfavorable because 2005 included income tax benefits of $9.7 million from settlement of U.S. income tax audits.

Sales and other operating revenues in 2006 were $2.6 billion higher than in 2005 mostly due to higher sales volumes and sales prices in the current year for refined petroleum products. In addition, merchandise sales at retail gasoline stations increased in 2006 and the sales price of crude oil was higher in 2006. Sales revenue was unfavorably affected in 2006 by lower sales volumes of crude oil and lower sales volumes and prices for natural gas. Gain on sale of assets before income taxes amounted to $9.4 million in 2006 compared to $175.1 million in 2005. The prior year included a pretax gain of $165.0 million related to the sale of oil and natural gas properties on the Gulf of Mexico continental shelf. Interest and other income in 2006 was unfavorable to the prior year by $3.3 million due mostly to higher foreign exchange charges associated with the unfavorable effects of the U.S. dollar weakening against the Euro and pound sterling in the current year. Crude oil and product purchases expense increased by $2.4 billion in 2006 compared to 2005 due to higher prices for crude oil and other purchased refinery feedstocks, higher prices and volumes of refined petroleum products purchased for sale at retail gasoline stations, and higher levels of merchandise purchased for sale at these gasoline stations. These higher costs were partially offset by lower volumes of crude oil purchased for feedstock in 2006 because the Meraux refinery was off-line for repairs for the first five months of the year. Operating expenses increased by $254.6 million in 2006 compared to 2005 due to higher repairs and other production expenses in the Company s E&P operations, higher costs of operating retail gasoline stations primarily due to more stations in operation, and higher refinery operating costs mostly associated with higher labor costs at the Company s Meraux refinery. Exploration expenses were lower in 2006 compared to 2005 by $13.2 million primarily due to lower dry hole charges in the current year in the Republic of Congo, but partially offset by higher dry hole and seismic and geophysical costs in the U.S. The reasons for higher costs associated with hurricanes in 2006 were included in the previous paragraph. Selling and general expenses increased $69.6 million in 2006 due to various factors in the year, including the pretax costs for an educational assistance contribution commitment, the costs of reorganizing the Company s U.S. E&P operations, higher costs for professional consultants, and the initial costs of expensing the grant-date fair value of stock options which began in 2006. Depreciation, depletion and amortization expense was $12.8 million lower in 2006 than 2005 generally due to lower volumes of crude oil and natural gas sold by the Company s E&P business. Depreciation expense in the downstream business was higher in 2006 mostly due to the continued addition of retail gasoline stations in the U.S. Accretion of asset retirement obligations increased by $1.2 million in 2006 mostly due to higher asset retirement obligations for Malaysian operations due to drilling development wells at the Kikeh field in 2006. Interest expense increased in 2006 by $5.2 million due to higher average borrowings under the Company s credit facilities. The amount of interest costs capitalized to development projects increased by $4.5 million in 2006 compared to 2005 due to higher capitalized costs associated with the Kikeh field, offshore Sabah Malaysia, and the Thunder Hawk field in the deepwater Gulf of Mexico. Income tax expense in 2006 was lower than in 2005 by $144.0 million due to lower pretax earnings in 2006 and net tax benefits in the current year from changes in tax rates in various taxing jurisdictions. The effective income tax rate for consolidated earnings in 2006 was 37.9% and included a net benefit of $19.7 million (1.9% of pretax income) from the reduction of Federal and provincial tax rates in Canada offset in part by an increase in the tax rate on oil operations in the U.K. The effective tax rate in 2005 was 38.9% of consolidated pretax earnings. The tax rate in both years was higher than the U.S. federal statutory tax rate of 35.0% due to a combination of U.S. state taxes, certain foreign tax rates that exceed the U.S. federal tax rate, and certain exploration and other expenses in foreign taxing jurisdictions for which no income tax benefit is currently being recognized because the ability to obtain tax benefits for these costs in future years is uncertain.

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 was $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 E&P and R&M operations and lower net costs for 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 both the U.S. and U.K. in 2005 by adding 112 retail gasoline sites 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 $0.05 in 2005 and $1.10 in 2004. Income from discontinued operations 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 property 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 other than the western Canada assets included in discontinued operations. 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 operation 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 temporarily shut-down certain offshore U.S. oil and gas production facilities and the Meraux, Louisiana refinery, led to uninsured repair costs of about $15.5 million in 2005 and caused insurance costs in 2005 to rise by approximately $23.0 million. Also included in this cost category in 2005 was $19.5 million of ongoing Meraux refinery salaries, benefits, depreciation and maintenance costs while the refinery was 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 was allocated to all segments of the Company s business as all assets were covered by this property insurance. Costs associated with hurricanes were $3.4 million in 2004. 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

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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 $0.3 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.

Segment Results In the following table, the Company s results of operations for the three years ended December 31, 2006 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)	**2006**	**2005**	**2004**
Exploration and production			
United States	$ 212.4	385.5	159.5
Canada	329.7	308.2	232.2
United Kingdom	60.7	79.9	87.1
Ecuador	38.4	38.1	6.6
Malaysia	(5.9)	(4.7)	38.3
Other	(19.4)	(58.9)	(11.4)
	615.9	748.1	512.3
Refining and marketing			
North America	73.4	85.5	53.4
United Kingdom	31.7	39.8	28.5
	105.1	125.3	81.9
Corporate	(82.7)	(35.5)	(97.8)
Income from continuing operations	638.3	837.9	496.4
Income from discontinued operations		8.6	204.9
Net income	$ 638.3	846.5	701.3

Exploration and Production Earnings from exploration and production operations were $615.9 million in 2006, $748.1 million in 2005 and $512.3 million in 2004. The $132.2 million reduction in 2006 earnings compared to 2005 was mostly attributable to lower production of crude oil and natural gas, which led to lower sales volumes for these products. Lower natural gas sales prices and higher production and administrative expenses in 2006 and a $104.5 million after-tax gain on sale of oil and natural gas properties on the continental shelf of the Gulf of Mexico in 2005 also were factors that led to lower E&P earnings in the current year. E&P earnings in 2006 were favorably impacted by higher realized oil sales prices, lower exploration expenses, lower hurricane-related expenses and income tax benefits associated with tax rate changes enacted in the current year. Crude oil sales volumes were down in 2006 by 13% compared to 2005, while natural gas sales volumes were down by 17%. Oil sales volumes were lower in 2006 primarily due to lower production at the Front Runner and Habanero fields in the Gulf of Mexico caused by weaker field performances, lower production at the Terra Nova field, offshore Newfoundland, due to the field being shut-in for six months for major equipment repairs, and lower production at West Patricia, offshore Sarawak Malaysia, due to a lower volumetric sharing percentage allocable to the Company as the field matures. The decline in natural gas sales volumes in 2006 was attributable to both the mid-2005 sale of mature gas properties on the Gulf of Mexico continental shelf and lower production in the current year from gas fields onshore south Louisiana. The Company s average worldwide realized crude oil sales price increased 14% in 2006, while the average realized sales price for North American natural gas decreased 10%.

The 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. These 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

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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 results of operations for oil and gas producing activities for each of the last three years are shown by major operating areas on pages F-38 and F-39 of this Form 10-K report. Average daily production and sales rates and weighted average sales prices are shown on page 6 of the 2006 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)	2006	2005	2004
United States			
Oil and gas liquids	$ 440.1	448.8	248.4
Natural gas	160.4	216.6	207.6
Canada			
Conventional oil and gas liquids	476.0	519.7	403.3
Natural gas	24.1	29.7	28.7
Synthetic oil	270.0	224.7	174.2
United Kingdom			
Oil and gas liquids	156.8	159.8	146.8
Natural gas	23.3	19.9	11.4
Malaysia crude oil	219.6	232.9	167.2
Ecuador crude oil	122.7	116.6	30.8
Total oil and gas revenues	$ 1,893.0	1,968.7	1,418.4

The Company s crude oil, condensate and natural gas liquids production from continuing operations averaged 87,817 barrels per day in 2006, 101,349 barrels per day in 2005 and 93,634 barrels per day in 2004. Production of crude oil, condensate and natural gas liquids was 13% lower in 2006 compared to 2005 primarily due to lower volumes produced in the U.S. Gulf of Mexico and offshore eastern Canada. U.S. oil production of 21,112 barrels per day in 2006 was down by 18% from 2005 levels. The reduction in the U.S. related to lower volumes at two deepwater fields in the Gulf of Mexico Front Runner and Habanero and oil volumes produced in 2005 from fields on the continental shelf that were sold in the middle of that year. Front Runner has experienced a series of well failures that require intervention work. Habanero production decreased due to decline at the most productive onstream well during 2006. U.S. oil production in 2006 was virtually unaffected by downtime for tropical storms and hurricanes, while 2005 volumes were adversely affected by downtime associated with Hurricanes Katrina and Rita. Production offshore the East Coast of Canada comes from two fields Hibernia and Terra Nova. Terra Nova was off production for about one-half of 2006 for major equipment repairs. The floating production, storage and offloading vessel was taken to Europe for turnaround and production restarted in mid-November 2006. Production at Terra Nova was 3,900 barrels per day in 2006, down 64% from 2005 levels. Production at Hibernia totaled 10,996 barrels per day, which was 10% below 2005, with the decline due primarily to more downtime for equipment reliability issues in 2006. Total heavy oil production in the Western Canadian Sedimentary Basin (WCSB) increased 7% in 2006 and totaled 12,613 barrels per day. This increase was attributable to an ongoing development drilling program during 2006 at the Seal field in Alberta. Light oil production in the WCSB fell 21% to 443 barrels per day in 2006 mostly due to less condensate produced at the Rimbey gas field in Alberta. Synthetic oil production at Syncrude increased 10% in 2006 and was 11,701 barrels per day. A third coker unit was started up during 2006, and the new unit permits a larger volume of bitumen to be processed at the plant. The new coker experienced various start up issues, but was operating near capacity at year-end 2006. All oil production in Malaysia during 2006 came from the West Patricia and adjoining Congkak fields in Block SK 309 offshore Sarawak. Net oil production from Malaysia was 11,298 barrels per day in 2006, 16% lower than in 2006 as the production sharing contract allocates a smaller portion of gross production to the Company s account in both a higher price environment and as prior costs are recovered. Gross production volumes at the Malaysian fields fell only 5% in 2006. A major oil field known as Kikeh in Block K offshore Sabah, Malaysia is scheduled to start-up in the second half of 2007. Oil production offshore the United Kingdom fell 11% to 7,146 barrels per day. The most significant U.K. decline in 2006 occurred at the Schiehallion field and was primarily caused by a fire at the facilities used by this field. Total net oil produced at Block 16 in Ecuador was 8,608 barrels per day in 2006, a 9% increase from 2005 as a development drilling campaign continued in 2006. Oil sales volumes in Ecuador significantly exceeded production in 2006 due to recovering 853,000 barrels of oil for sale in settlement of a dispute with partners over 2004 oil production that was originally withheld from the Company.

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Oil production in 2005 was an annual record for Murphy Oil. The 8% increase in worldwide oil production in 2005 compared to 2004 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. 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.

Worldwide sales of natural gas from continuing operations were 75.3 million cubic feet per day in 2006, 90.2 million in 2005 and 109.5 million in 2004. Sales of natural gas in the United States were 56.8 million cubic feet per day in 2006, 70.5 million in 2005 and 88.6 million in 2004. The reduced U.S. natural gas sales volume in 2006 of 19% was attributable to a combination of lower volumes produced onshore south Louisiana due to field decline and volumes produced in 2005 at Gulf of Mexico continental shelf fields that were sold in mid-2005. The Seventeen Hands field in Mississippi Canyon Block 299 came onstream in 2006, and volumes from this field served to essentially offset lower volumes at other deepwater Gulf of Mexico fields, including Tahoe, Front Runner and Habanero. U.S. natural gas sales volumes in 2006 were virtually unaffected by downtime for tropical storms and hurricanes, while volumes in 2005 were adversely affected by downtime associated with Hurricanes Katrina and Rita. Natural gas sales volumes in Canada were 9.8 million cubic feet per day in 2006, 10.3 million in 2005 and 14.0 million in 2004. The 6% reduction in natural gas sales volumes in western Canada in 2006 was mostly caused by normal field decline in the Rimbey area. Natural gas sales volumes in the United Kingdom in 2006 were 8.7 million cubic feet per day, while 2005 and 2004 volumes were 9.4 million and 6.9 million, respectively. The 2006 decline of 8% for natural gas sales volumes in the U.K. was wholly attributable to make-up gas volumes sold in 2005 at the Amethyst field that were associated with under-sold production in earlier years. Excluding the make-up volumes in 2005, U.K. natural gas sales volumes in 2006 would have exceeded 2005 amounts.

Natural gas 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 of Mexico 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 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. Canadian gas sales volumes decreased 26% in 2005 compared to 2004 mostly due to normal field decline at Rimbey area wells. U.K. natural gas sales volumes in 2005 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.

Worldwide crude oil sales prices have risen in each of the last two years due to the combination of a strong world economy, real and perceived instability in worldwide crude oil production levels, and effective production output controls by OPEC producers. The Company realized an average per barrel sales price of $51.63 for crude oil and condensate in 2006, up 14% from the 2005 average of $45.25 per barrel. The average realized oil sales price in 2006 in the U.S. was up 21% at $57.30 per barrel. The average sales price of Canadian heavy oil was $25.87 per barrel, also a 21% increase compared to 2005. Realized average prices per barrel for Hibernia and Terra Nova oil sales in 2006 were $63.48 and $59.79, respectively, with each up about 20% from 2005 averages. Synthetic oil production was sold at $63.23 per barrel in 2006, up 9% from 2005 prices. The realized sales price for synthetic oil did not rise as much as other oil because of higher volumes of similar crudes available in the market for which demand did not keep pace with the growth. Average

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crude oil prices in Malaysia of $51.78 per barrel in 2006 was 12% higher than 2005, while U.K. prices for the latest year rose 22% to $64.30 per barrel. The average oil price realized in Ecuador of $33.79 per barrel rose only 4% from 2005 as the Ecuadorian government passed a revenue sharing law that became effective in April 2006. Oil producers in Ecuador must now revenue-share 50% of average realized prices that exceed a benchmark price that escalates with the inflation rate as measured monthly by the U.S. Consumer Price Index. At year-end 2006, this benchmark oil price for Block 16 Ecuador was approximately $23.27 per barrel.

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 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 in 2005 for Hibernia and Terra Nova production offshore eastern Canada was $51.37 per barrel, an increase of 40%. The synthetic oil production sales price rose 44% in 2005 and averaged $58.12 per barrel. Sales prices in 2005 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.

North American natural gas sale prices did not rise in tandem with higher crude oil prices in 2006 as U.S. natural gas storage levels exceeded normal levels during most of the year, primarily due to milder average temperature across much of the U.S. during the period. North American gas sales prices averaged $7.57 per thousand cubic feet (MCF) in 2006, down 10% from 2005 averages. The sales price for natural gas in the U.K. was up 27% and averaged $7.34 per MCF.

The 2005 sales prices for natural gas in the Company s gas producing markets were stronger than in 2004. The Company s sales price of North American natural gas averaged $8.44 per MCF in 2005, 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.

Based on 2006 sales volumes and deducting taxes at marginal rates, each $1.00 per barrel and $0.10 per MCF fluctuation in prices would have affected earnings from exploration and production operations by $20.9 million and $1.7 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 $384.6 million in 2006, $305.4 million in 2005 and $249.0 million in 2004. These amounts are shown by major operating area on pages F-38 and F-39 of this Form 10-K report. Costs per equivalent barrel excluding discontinued operations during the last three years are shown in the following table.

(Dollars per equivalent barrel)	**2006**	**2005**	**2004**
United States	$ 7.10	5.17	6.14
Canada			
Excluding synthetic oil	9.36	4.40	3.06
Synthetic oil	28.54	25.09	18.05
United Kingdom	6.19	5.10	4.25
Malaysia	7.46	6.98	5.63
Ecuador	7.85	7.07	11.18
Worldwide excluding synthetic oil	7.91	5.31	4.89

Production cost per equivalent barrel increased in the United States in 2006 mostly due to higher insurance costs coupled with lower overall production. The lower cost per equivalent barrel in the U.S. 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 per-unit costs for Canadian conventional oil and gas operations, excluding Syncrude, rose significantly in 2006 due to lower production volumes and higher repair costs at Terra Nova, which was shut-in for about six months for major equipment repairs, plus a higher mix of more costly heavy oil production versus lighter oils. 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 production costs per barrel for synthetic oil operations in 2006 were mostly attributable to higher coker repair costs and higher compensation costs. The higher rate per barrel for Canadian synthetic oil operations in 2005 compared to 2004 was due to unfavorable maintenance, energy and compensation costs coupled with lower production and a higher foreign exchange rate. Higher 2006 costs per barrel produced in the U.K. and Malaysia were mostly attributable to higher facility maintenance costs. 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. The increase in the unit rate in

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Malaysia in 2005 was due to higher fuel and export duty costs. Higher per-unit operating costs in Ecuador in 2006 compared to 2005 were mostly attributable to higher field operating costs in the Amazon region where Block 16 is located. Lower average costs per barrel in Ecuador in 2005 were due mostly to a new, less expensive arrangement for pipeline transportation that began near year-end 2004.

Exploration expenses for each of the last three years are shown in total in the following table, and amounts are reported by major operating area on pages F-38 and F-39 on this Form 10-K report. Certain of the expenses are included in the capital expenditures total for exploration and production activities.

(Millions of dollars)	**2006**	**2005**	**2004**
Exploration and production			
Dry holes	$ 111.0	126.0	110.9
Geological and geophysical	73.1	73.4	28.4
Other	12.6	10.2	8.6
	196.7	209.6	147.9
Undeveloped lease amortization	22.5	22.8	16.4
Total exploration expenses	$ 219.2	232.4	164.3

Dry holes expense was $15.0 million lower in 2006 than 2005 mostly due to less unsuccessful wildcat drilling in the Republic of Congo in the current year, but partially offset by higher unsuccessful drilling costs in the U.S. Gulf of Mexico. Dry hole expense was up $15.1 million in 2005 compared to 2004 as dry hole costs offshore the Republic of Congo and Malaysia were only partially offset by lower costs in the deepwater Gulf of Mexico and offshore eastern Canada. Geological and geophysical (G&G) expenses in 2006 were about the same as in 2005 as higher current-year costs in the Gulf of Mexico were essentially offset by lower spending offshore eastern Canada. G&G expenses were higher by $45.0 million in 2005 compared to 2004 mostly due to more 3-D seismic acquisition and processing costs in Blocks SK 309/311 and PM 311/312, offshore Malaysia. Other exploration costs in 2006 were $2.4 million higher than in 2005 mostly due to higher administrative costs for international exploration activities. Other exploration expenses were $1.6 million higher in 2005 than in 2004 due mostly to more administrative costs in the Republic of Congo. Undeveloped leasehold amortization expense in 2006 was virtually flat with 2005, while such costs increased by $6.4 million in 2005 compared to 2004 because of lease acquisitions 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 $1.9 million, $18.8 million and $2.6 million were incurred in 2006, 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 2005, these costs were adversely affected by Hurricanes Katrina and Rita, and also included discretionary assistance to employees in the New Orleans area after Hurricane Katrina. 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 $297.0 million in 2006, $319.1 million in 2005 and $241.5 million in 2004. The $22.1 million reduction in 2006 compared to 2005 was attributable to lower oil and natural gas sales volumes in the current year, but partially offset by generally higher per-barrel capital amortization caused by higher costs for development operations and negative U.S. reserve revisions. The $77.6 million increase in 2005 versus 2004 was due to more crude oil production and higher per-barrel costs in most areas generally caused by higher capital costs incurred to find and develop oil and natural gas reserves. Despite a weakening of oil prices in early 2007, the Company continues to experience high drilling and related costs caused by a strong demand for such services.

The exploration and production business recorded expenses of $10.8 million in 2006, $9.6 million in 2005 and $9.9 million in 2004 for accretion on discounted abandonment liabilities. Because the abandonment liabilities are carried on the balance sheet at a discounted fair value, accretion must be recorded annually so that the liability will be recorded at full value at the projected time of abandonment. The higher accretion costs incurred in 2006 were mostly associated with retirement obligations incurred on development wells drilled at the Kikeh field during 2006.

The effective income tax rate for exploration and production operations was 36.1% in 2006, 39.1% in 2005 and 32.7% in 2004. Although the 2006 effective tax rate was only slightly higher than the U.S. statutory tax rate of 35%, the annual rate was lower than in 2005 mostly due to net benefits from tax rate changes. In 2006 the Canadian federal government and the Alberta and Saskatchewan provinces reduced their tax rates on oil and gas company profits, which led to a recognition of tax benefits of $37.5 million in 2006 mostly due to reducing recorded deferred income tax liabilities. In

2006, the U.K. government increased tax rates on oil and gas company profits from 40% to 50%, which increased income tax expense in the U.K. by $17.8 million in 2006. 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 Blocks H, P, L and M, offshore Sabah, and Blocks PM 311/312, offshore Peninsula Malaysia. The effective tax rate in 2004 was lower than the U.S. statutory rate partially due to recognition of deferred income tax benefits in Malaysia of $31.9 million, which arose due to the expectation that temporary differences associated with exploration and other expenses incurred in Block K Malaysia will be utilized to reduce future taxable income. This benefit had not been recognized in the income statement before 2004 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 the province of Alberta reduced its tax rate for oil and gas companies which generated a $4.9 million benefit in that year.

At December 31, 2006, approximately 39% of the Company s U.S. proved oil reserves and 52% of the U.S. proved natural gas reserves are undeveloped. Virtually all of the total U.S. undeveloped reserves (on a barrel of oil equivalent basis) are associated with the Company s various deepwater Gulf of Mexico fields. Further drilling, facility construction and well workovers are required to move undeveloped reserves to developed. In addition in Malaysia, all oil and natural gas reserves of 47.5 million barrels and 74.6 billion cubic feet at year-end 2006 for the Kikeh field in Block K are undeveloped pending completion of facilities and development drilling prior to first production, which is projected to occur in the second half of 2007 for oil and in early 2008 for natural gas. Also in Malaysia, there were 262.9 billion cubic feet of undeveloped natural gas reserves at various fields offshore Sarawak at year-end 2006, pending completion of drilling and facilities. First gas production at these Sarawak fields is expected in the first half of 2009. On a worldwide basis, the Company spent approximately $560 million in 2006, $378 million in 2005 and $272 million in 2004 to develop proved reserves. The Company expects to spend about $714 million in 2007, $485 million in 2008 and $99 million in 2009 to move currently undeveloped proved reserves to the developed category.

Refining and Marketing The Company s refining and marketing (R&M) operations generated earnings of $105.1 million in 2006, $125.3 million in 2005 and $81.9 million in 2004. The 16% decline in earnings during the current year was primarily due to hurricane related after-tax costs of $67.1 million and lower crude oil throughput volumes at the Meraux, Louisiana refinery. In late August 2005, the Meraux refinery experienced severe flooding and wind damage associated with Hurricane Katrina and was shut down from late August 2005 through mid-2006. The hurricane related costs in 2006 were partially offset by stronger refining margins generated by the Superior, Wisconsin refinery and continued growth in the Company s North American retail gasoline marketing activities.

In 2005, R&M earnings increased 53% compared to 2004. In North America, earnings improved 60% mostly due to stronger marketing margins, while in the U.K. income improved 40% due to stronger margins in both refining and marketing.

The Company s North American R&M operations generated earnings of $73.4 million in 2006, $85.5 million in 2005 and $53.4 million in 2004. North American operations include refining activities in the United States and marketing activities in the United States and Canada. The 2006 and 2005 operating results for the Company s North American refining business were negatively impacted by hurricane related costs and below optimal Meraux refinery crude throughput volumes as a result of Hurricane Katrina. Uninsured damages, higher insurance premiums, settlement of the class action oil spill litigation and other hurricane related pretax costs in the Company s North American operations were $107.3 million in 2006, compared to pretax hurricane costs of $46.3 million in 2005. In 2006, the Meraux refinery throughput volumes for crude oil and other feedstocks averaged 57,198 barrels per day, compared to an average throughput of 75,443 and 107,622 barrels per day in 2005 and 2004, respectively. Significant flooding and wind damage associated with Hurricane Katrina resulted in the refinery being shut down from late August 2005 through mid-2006. During the refinery s nine months of downtime, major upgrades and improvements were completed in conjunction with the hurricane related repairs, including turnarounds on the refinery s hydrocracker and fluid catalytic cracking unit debutanizer. Meraux refinery throughput volumes increased to approximately 117,000 barrels per day following the debutanizer turnaround in December 2006. The Company s refinery in Superior, Wisconsin generated record earnings for the year as a result of steady operations and the continued strength of industry refining margins in North America. The 2006 operating results for the Company s North American retail operations remained strong, with higher average fuel and non-fuel sales volumes at its retail sites as well as continued additions to the number of stations in operation. Retail fuel sales volumes increased 22% in 2006 compared to fuel sales volumes in 2005. The Company increased the size of its retail gasoline operations in 2006 by adding 123 Murphy USA fueling stations in the parking lots of Wal-Mart Supercenters in a 21-state area. This resulted in a 14% increase in the number of sites at year-end 2006 compared to 2005.

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Operating results for the Company s refining business in 2005 were slightly better than 2004. During the first eight months of 2005 the Company benefited from strong industry refining margins due to increased demand for gasoline and distillates fueled by the robust U.S. economy. Higher refinery margins for both the Meraux and Superior refineries were mostly offset by the effects of four months of lost production and $29.0 million of after-tax hurricane related costs at the Meraux refinery following Hurricane Katrina. Operating results for the North American retail gasoline marketing operations were stronger in 2005 compared to 2004 due to a combination of higher per-gallon fuel margins, higher average per-site fuel and non-fuel sales volumes and the continued addition of sites. In 2005, the Company increased the size of its retail fuel operations by adding 112 Murphy USA fueling stations at Wal-Mart Supercenters, leading to a 15% increase in the number of sites at year-end 2005 compared to 2004.

Unit margins (sales realization less costs of crude and other feedstocks, transportation to point of sale and refinery operating and depreciation expenses) averaged $3.48 per barrel in North America in 2006, $2.96 in 2005 and $2.25 in 2004. Despite the reduced throughputs at the Meraux refinery, North American refined product sales volumes increased 9% to a record 350,057 barrels per day in 2006, following a 7% increase to 322,171 barrels per day in 2005. The Company s North American retail gasoline marketing operations continued to increase per site fuel sales volumes with a 6% increase in the average monthly fuel sales volume per site in 2006 following a 9% increase in 2005.

Operations in the United Kingdom generated earnings of $31.7 million in 2006, compared to $39.8 million in 2005 and $28.5 million in 2004. The decrease in 2006 earnings was due primarily to lower refinery margins as a result of higher operating and transportation costs in the current year and nonrecurring credits in 2005 for property tax rebates and insurance settlements. The decline in refinery earnings in 2006 was partially offset by stronger marketing margins and higher marketing sales volumes as a result of the contribution from 68 retail sites acquired in 2005.

Unit margins in the United Kingdom averaged $6.39 per barrel in 2006, $6.36 per barrel in 2005 and $4.85 per barrel in 2004. Overall sales of refined products declined 2% in 2006, following a decline of 4% in 2005. The decline in 2006 sales volumes was primarily due to lower demand for refined products based on higher average sales prices, while the decline in 2005 was due to lower production at the Milford Haven, Wales refinery as a result of a planned turnaround.

Based on sales volumes for 2006 and deducting taxes at marginal rates, each $0.42 per barrel ($0.01 per gallon) fluctuation in the unit margins would have affected annual refining and marketing profits by $37.1 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 after-tax costs of corporate activities, which include interest income, interest expense, foreign exchange gains and losses, and corporate overhead not allocated to operating functions, were $82.7 million in 2006, $35.5 million in 2005, and $97.8 million in 2004. Net corporate costs were $47.2 million higher in 2006 than 2005 primarily due to a $25.1 million after-tax educational assistance contribution commitment recorded in 2006, unfavorable foreign exchange impacts and lower income tax benefits in 2006. The educational assistance commitment, known as the El Dorado Promise , involves the Company s unconditional commitment to contribute $5.0 million per year for the next 10 years to pay for post-secondary tuition for eligible graduates of El Dorado High School in Arkansas. The U.S. dollar weakened by 14% against the U.K. pound sterling and 12% against the Euro during 2006. The U.S. dollar exchange rate against the Canadian dollar was not significantly different in 2006 compared to 2005. The after-tax earnings effect of the weaker U.S. dollar in 2006 was $7.9 million, while the foreign exchange effect on 2005 was insignificant. The 2005 corporate results included $9.7 million of income tax benefits due to refund and settlement of prior year U.S. income tax matters. Interest income was higher by $4.9 million in 2006 mostly due to interest collected on favorable settlements of prior-year lawsuits and other disagreements with partners on E&P projects in Ecuador and western Canada. Administrative expenses in the corporate area were $40.2 million higher in 2006 mostly due to the educational assistance commitment, plus higher costs associated with initial recognition of the grant-date fair value of stock options beginning in 2006. These higher administrative expenses were partially offset in 2006 by lower other incentive compensation costs. Interest expense was $5.2 million higher in 2006 mostly due to higher average outstanding borrowings under credit facilities. The portion of interest capitalized to development projects increased by $4.5 million in 2006 due mostly to higher capital spending on the Kikeh field development, offshore Sabah, Malaysia, and for the Thunder Hawk field in the Gulf of Mexico, partially offset by lower interest capitalized on the now completed expansion at Syncrude.

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 U.S. income tax matters. 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.

Capital Expenditures

As shown in the selected financial data on page 14 of this Form 10-K report, capital expenditures for continuing operations, including exploration expenditures, were $1,262.5 million in 2006 compared to $1,329.8 million in 2005 and $975.4 million in 2004. These amounts included $196.7 million, $209.6 million and $147.9 million, respectively, in 2006, 2005 and 2004 for exploration costs that were expensed. Capital expenditures for exploration and production activities totaled $1,082.8 million in 2006, $1,092.0 million in 2005 and $839.2 million in 2004, representing 86%, 82% and 86%, respectively, of the Company s total capital expenditures for these years. E&P capital expenditures in 2006 included $13.9 million for acquisition of undeveloped leases, $338.0 million for exploration activities, and $730.9 million for development projects. Development expenditures included $65.7 million for deepwater fields in the Gulf of Mexico; $387.9 million for the Kikeh field in Malaysia; $42.2 million for synthetic oil expansion and other capital at the Syncrude project in Canada; $89.7 million for western Canada heavy oil and natural gas projects; and $42.1 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-37 of this Form 10-K report.

Refining and marketing capital expenditures totaled $173.4 million in 2006, compared to $202.4 million in 2005 and $134.7 million in 2004. These amounts represented 14%, 15% and 14% of capital expenditures for continuing operations of the Company in 2006, 2005 and 2004, respectively. Refining capital spending was $57.3 million in 2006 compared to $34.1 million in 2005 and $46.1 million in 2004. The bulk of the refining capital in 2006 was spent at the Meraux, Louisiana refinery where numerous capital improvements were completed while the plant was shut-down for repairs following Hurricane Katrina. In 2004, the Company completed the construction of a green gasoline unit to produce ultra low-sulfur gasoline at its Superior, Wisconsin refinery, with capital spending in that year for this project of $18.0 million. Marketing expenditures amounted to $116.1 million in 2006, $168.2 million in 2005 and $88.6 million in 2004. 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 123 total stations to this retail station network in 2006, 112 in 2005 and 129 in 2004. 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 $962.7 million in 2006, $1,216.7 million in 2005 and $1,035.1 million in 2004. Cash provided by operations in 2006 was about $254 million lower than in 2005 and was unfavorably affected by higher spending in 2006 for inventories, prepaid insurance, and repair costs at the Meraux refinery, where the Company is awaiting anticipated reimbursements from insurance companies of $72.8 million at December 31, 2006. In addition, 2006 cash provided by operations was unfavorably affected by lower oil and natural gas sales volumes and higher operating costs associated with repairs of oil and gas production facilities. The increase in cash provided by continuing operations in 2005 compared to 2004 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 $16.1 million in 2006, $31.9 million in 2005 and $18.6 million in 2004. A complete scheduled turnaround occurred at the Milford Haven, Wales refinery in 2005.

Cash proceeds from property sales other than from discontinued operations were $23.8 million in 2006, $172.7 million in 2005 and $60.4 million in 2004. The sales proceeds in 2006 primarily related to sales of various properties, real estate and aircraft. The 2005 sales proceeds were mostly attributable to sale of most oil and gas properties on the continental shelf of the Gulf of Mexico; the Company retained its deepwater Gulf of Mexico properties. 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. Property sales which have been classified as discontinued operations brought in net cash proceeds of $583.0 million in 2004 and included sale of most of the Company s conventional oil and gas properties in western Canada. During 2006, the Company borrowed $237.7 million under notes payable primarily to fund a portion of the Company s development capital expenditures. Cash proceeds from stock option exercises and employee stock purchase plans, including certain income tax benefits on stock options classified as financing activities, amounted to $36.6 million in 2006, $26.5 million in 2005 and $3.2 million in 2004. Maturity of U.S. government securities provided cash of $17.9 million in 2005.

Property additions and dry hole costs used cash of $1,191.7 million in 2006, $1,246.2 million in 2005 and $938.4 million in 2004. Lower amounts used in 2006 compared to 2005 were mostly attributable to acquisition in 2005 of 68 retail fueling stations in the U.K. marketing operations. For E&P operations, higher costs in 2006 for development drilling at the Kikeh field in Block K Malaysia and exploration drilling in the Gulf of Mexico were mostly offset by lower costs in the year for Syncrude expansion and exploration drilling in the Republic of Congo. The increase in spending in 2005 versus 2004 was mainly caused by development activities at the Kikeh field offshore Sabah, Malaysia, and acquisition of the U.K. retail fueling stations. Cash used in other investing activities of $10.8 million in 2006 and $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 in 2004 and was mostly accomplished using a portion of the proceeds of asset dispositions classified as discontinued operations. 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 $98.2 million in 2006, $83.2 million in 2005 and $78.2 million in 2004. The Company raised its annualized dividend rate from $0.45 per share to $0.60 per share beginning in the third quarter of 2006. The Company had previously increased the annualized dividend rate from $0.40 per share to $0.45 per share beginning in the third quarter of 2004.

Financial Condition

Year-end working capital (total current assets less total current liabilities) totaled $796.0 million in 2006, $551.9 million in 2005 and $424.4 million in 2004. 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 $389.5 million below fair value at December 31, 2006. Cash and cash equivalents at the end of 2006 totaled $543.4 million compared to $585.3 million at year-end 2005 and $535.5 million at year-end 2004.

The long-term portion of debt increased by $230.7 million during 2006 and totaled $840.3 million at year-end 2006, which represented 17.2% of total capital employed. The increase in long-term debt in 2006 was necessitated by the Company s funding of significant ongoing oil and natural gas development projects, with the largest of these being the Kikeh field in Malaysia. Long-term debt included $7.1 million of nonrecourse debt borrowed in connection with the Hibernia oil field development all of which is scheduled to be repaid by 2009. Long-term debt was reduced by $3.8 million in 2005 as the Company utilized internal cash flow generated by operations to fund its capital program. Stockholders equity was $4.05 billion at the end of 2006 compared to $3.46 billion a year ago and $2.65 billion at the end of 2004. 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 2006 balance sheet compared to 2005 included a $129.9 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 2006 compared to 2005, and higher amounts recoverable from insurance companies at year-end 2006, which are mostly related to hurricane related repair costs at the Meraux refinery. Inventory values were $96.1 million higher at year-end 2006 than in 2005 mostly because of more refined product volumes held in storage at the Meraux refinery and retail fueling stations, and more drilling equipment held in inventory in Malaysia. Prepaid expenses increased $103.4 million primarily due to higher prepaid costs on property insurance policies and higher prepaid Canadian income taxes. Short-term deferred income tax assets decreased $19.4 million at year-end 2006 due mostly to changes in the components of temporary differences in the U.S. and U.K. Net property, plant and equipment increased by $732.1 million in 2006 as property additions during the year were larger than the additional depreciation and amortization expensed. Deferred charges and other assets increased $77.2 million in 2006 due to both additional prepayments on future asset rentals for the Kikeh field in Malaysia and the higher noncurrent portion of amounts expected to be recoverable from insurance companies related mostly to repairs at the Meraux refinery. Current maturities of long-term debt were not materially different at year-end 2006 compared to 2005. Notes payable increased $2.7 million in 2006 due to short-term borrowings by one of the Company s consolidated subsidiaries. Accounts payable rose by $21.4 million at year-end 2006 compared to 2005 mostly due to amounts owed for the oil spill class action settlement agreement at the Meraux, Louisiana refinery, partially offset by lower amounts owed for crude oil purchases and capital expenditures. Income taxes payable decreased $42.9 million at year-end 2006 due to higher tax installments paid relative to taxes accrued in the current year. Other taxes payable increased $37.7 million mostly due to higher sales, use and excise taxes

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owed at year-end 2006 compared to 2005. Deferred income tax liabilities decreased $32.2 million in 2006 due mostly to Canadian tax rate reductions enacted during the year. The liability associated with asset retirements increased by $61.1 million mostly due to development wells drilled during 2006 offshore Malaysia and in the Gulf of Mexico. Accrued major repair costs increased by $15.9 million primarily based on recording additional costs for future turnarounds of the Company s three refineries, which exceeded the turnaround amounts expended in 2006 that were charged against this liability. Deferred credits and other liabilities at the end of 2006 were $162.6 million higher than 2005 primarily due to the recording at year-end 2006 of liabilities for underfunded retirement plans and an educational assistance contribution commitment. Minority interest in a consolidated subsidiary at the end of 2006 of $23.3 million related to the 20% of Berkana Energy Corp. that the Company does not own. The Company acquired 80% of Berkana Energy Corp. in December 2006 in exchange for a non-cash contribution of the Company s Rimbey property in Alberta.

Murphy had commitments for future capital projects of $922.6 million at December 31, 2006, including $105.9 million for costs to develop deepwater Gulf of Mexico fields, $555.2 million for field development and future work commitments in Malaysia, $69.5 million for exploration drilling in the Republic of Congo and $18.1 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, 2006, the Company had access to long-term revolving credit facilities in the amount of $1.04 billion. No amounts were borrowed under these revolving credit facilities at year-end 2006. These credit facilities were renewed for one additional year and were increased slightly in mid-2006. The most restrictive covenants under these existing credit facilities limit the Company s long-term debt to capital ratio (as defined in the agreements) to 60%. At December 31, 2006, the long-term debt to capital ratio was approximately 17.2%. At December 31, 2006, the Company had borrowed $235.0 million under uncommitted credit lines and had additional uncommitted amounts available of approximately US $771.0 million in a combination of U.S. and Canadian dollars. In addition, the Company has a shelf registration on file with the U.S. Securities and Exchange Commission that permits the offer and sale of up to $650 million in debt and/or equity securities. Current financing arrangements are set forth more fully in Note E to the consolidated financial statements. Based on its 2007 Budget, the Company anticipates utilizing most of its long-term borrowing capacity under existing credit facilities during the year to fund certain ongoing 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 February 28, 2007, the Company s long-term debt rating by Standard & Poor s was BBB and by Moody s Investors Service was Baa2 . The Company has a rating of A (low) from Dominion Bond Rating Service. In February 2007, Moody s stated that it is reviewing the Company s debt rating for a possible future downgrade. The Company s ratio of earnings to fixed charges was 15.9 to 1 in 2006, 24.7 to 1 in 2005 and 13.4 to 1 in 2004.

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.

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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 mandated requirements for low-sulfur gasoline are effective in 2008 and both of the Company s U.S. refineries have been expanded and are now capable of producing the required low-sulfur gasoline. Each of the U.S. refineries must begin to produce the EPA required ultra low-sulfur diesel (ULSD) beginning in 2010. The Meraux refinery is currently capable of producing this ULSD for approximately half of its diesel production, but the Superior refinery is not yet capable of meeting the ULSD standard. The Company s management is currently studying alternatives available for fully meeting this ULSD standard at Meraux and Superior.

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 70 service stations, for which known or potential obligations for environmental remediation exist. In addition the Company operates or has operated numerous oil and gas fields that may require some form of remediation.

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

The Company s liability for remedial obligations includes certain amounts that are based on anticipated regulatory approval for proposed remediation of former refinery waste sites. Although regulatory authorities may require more costly alternatives than the proposed processes, the cost of such potential alternative processes is not expected to exceed the accrued liability by a material amount.

The EPA currently considers the Company to be a Potentially Responsible Party (PRP) at two Superfund sites. The potential total cost to all parties to perform necessary remedial work at these sites may be substantial. Based on currently available information, the Company believes that it is a de minimis party as to ultimate responsibility at both Superfund sites. The Company has not recorded a liability for remedial costs on Superfund sites. The Company could be required to bear a pro rata share of costs attributable to nonparticipating PRPs or could be assigned additional responsibility for remediation at the two sites or other Superfund sites. The Company believes that its share of the ultimate costs to clean-up the two Superfund sites will be immaterial and will not have a material adverse effect on its net income, financial condition or liquidity in a future period.

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

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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, 2006.

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 $2.3 million in 2006. 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 $41.7 million in 2006 and are projected to be $58.9 million in 2007.

Other Matters

Impact of inflation General inflation was moderate during the last three years in most countries where the Company operates; however, the Company s revenues and capital and operating costs are influenced to a larger extent by specific price changes in the oil and gas and allied industries than by changes in general inflation. Crude oil and petroleum product prices generally reflect the balance between supply and demand, with crude oil prices being particularly sensitive to OPEC production levels and/or attitudes of traders concerning supply and demand in the near future. Natural gas prices are affected by supply and demand, which to a significant extent are affected by the weather and by the fact that delivery of gas is generally restricted to specific geographic areas. Because crude oil and natural gas sales prices have generally strengthened during the last several years, prices for oil field goods and services have risen (with certain of these price increases such as drilling rig day rates having been significant), and prices could continue to be adversely affected in the future. Due to the volatility of oil and natural gas prices, it is not possible to determine what effect these prices will have on the future cost of oil field goods and services, although the Company anticipates continued escalation in prices for certain equipment and services as long as oil prices remain strong.

Accounting changes and recent accounting pronouncements In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of SFAS Nos. 87, 88, 106 and 132R. This statement requires the Company to recognize in its consolidated balance sheet the overfunded or underfunded status of its defined benefit plans as an asset or liability and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This statement also requires that the Company measure the funded status of a plan as of December 31 rather than September 30 as previously permitted. The Company implemented this statement for the year ended December 31, 2006, except for the transition to a year-end measurement date which will occur in 2007. Refer to Note J for further information.

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

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

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. This statement was adopted by the Company on January 1, 2006 and it did not have a significant impact on the Company s results of operations.

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 was applied to new arrangements entered into beginning April 1, 2006 and was applied to all inventory transactions that were completed after December 15, 2006 for arrangements entered into prior to March 15, 2006. The adoption of this consensus in 2006 did not have a significant impact on the Company s financial statements.

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

In September 2006, the FASB issued FSP AUG AIR-1 which prohibits, effective January 1, 2007, the use of the accrue-in-advance method of accounting for planned major maintenance activities as historically used by the Company. Accordingly, the Company will elect to use the deferral method for accounting for planned major maintenance activities beginning in 2007. Under the deferral method, the actual cost of each planned major maintenance activity is deferred and amortized through the next turnaround. Upon adoption in 2007 the Accrued Major Repair Costs reported on the Consolidated Balance Sheets will be replaced by a non-current asset representing the net unamortized major maintenance cost at the end of each reporting period and this accounting change is expected to cause a one-time increase to retained earnings of the Company. All prior periods financial statements presented will be retrospectively restated upon adoption of this new standard. The Company is currently evaluating this FSP and has estimated the one-time after-tax credit to retained earnings to be approximately $70 million.

In June 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes. This interpretation clarifies the criteria for recognizing income tax benefits under FASB Statement No. 109, Accounting for Income Taxes, and requires additional financial statement disclosures about uncertain tax positions. The interpretation is effective beginning January 1, 2007. The Company is currently evaluating this interpretation and does not expect a significant impact on its financial statements.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This Statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This Statement applies under other accounting pronouncements that require or permit fair value measurements, and where applicable simplifies and codifies related guidance within GAAP and does not require any new fair value measurements. The Statement is effective for fiscal years beginning January 1, 2008. Provisions of the Statement are to be applied prospectively except in limited situations. The Company does not expect the initial adoption of this Statement to have a material impact on its financial statements.

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 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, 2006, the Company had a receivable of approximately $20.5 million related to VAT. In early 2007, Ecuadorian authorities settled this issue with the Company by agreeing to assign a portion of the government s future oil volumes to the Block 16 partners. The settlement had no material impact on the Company s financial position or net income.

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 usually do not approximate the average price that the Company expects to receive for its oil and natural gas production. The Company often uses significantly different oil and natural gas price and reserve assumptions when making its own internal economic property evaluations. Estimated reserves are subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of the Company s depreciation rates and the timing of settlement of asset retirement obligations.
The Company s proved reserves of oil and natural gas are presented on pages F-35 and F-36 of the 2006 annual report. The oil reserve revisions in 2006 in the U.S., Canada and Ecuador were based on performance of various local wells. The reserve revision in Malaysia in 2006 was mostly due to extension of proved oil in the Kikeh reservoir. The U.S. oil reserve revision in 2005 was mostly due to poor well performance at 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. Downward revisions to U.S. natural gas reserves in 2006 were mostly caused by unfavorable production performance for gas wells at various fields in the Gulf of Mexico and onshore south Louisiana. The significant upward revision of natural gas reserves in Malaysia in 2006 related to gas associated with the Kikeh field that will be sold to the local government beginning in 2008. 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 in the Consolidated Balance Sheet when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Costs for one exploration well in progress at year-end 2006 amounted to $3.2 million. Through February 2007, the well was determined to have successfully found hydrocarbon deposits and will be further evaluated for commerciality. Other wells in progress at year-end were insignificant.

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 prior-year well costs were $3.4 million in 2006 and $13.2 million in 2004; there were no dry holes in 2005 that were drilled in prior years.

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Impairment of long-lived assets The Company continually monitors its long-lived assets recorded in Property, Plant and Equipment and Goodwill in the Consolidated Balance Sheet to make sure that they are fairly presented. The Company must evaluate its properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. Goodwill is evaluated for impairment at least annually. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the amount of oil and natural gas that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, future capital and abandonment costs, future margins on refined products produced and sold, and future inflation levels. The need to test a property for impairment can be based on several factors, including but not limited to a significant reduction in sales prices for oil and/or natural gas, unfavorable reserve revisions, expected deterioration of future refining and/or marketing margins for refined products, or other changes to contracts, environmental regulations or tax laws. All of these same factors must be considered when evaluating a property s carrying value for possible impairment.

In making its impairment assessments involving exploration and production property and equipment, the Company must make a number of projections involving future oil and natural gas sales prices, future production volumes, and future capital and operating costs. Due to the volatility of world oil and gas markets, the actual sales prices for oil and natural gas have often been quite different from the Company s projections. Estimates of future oil and gas production and sales volumes are based on a combination of proved and risked probable and possible reserves. Although the estimation of reserves and future production is uncertain, the Company believes that its estimates are reasonable; however, there have been cases where actual production volumes were higher or lower than projected and the timing was different than the original projection. The Company adjusts reserves and production estimates as new information becomes available. The Company generally projects future costs by using historical costs adjusted for both assumed long-term inflation rates and known or expected changes in future operations. Although the projected future costs are considered to be reasonable, at times, costs have been higher or lower than originally estimated. In assessing potential impairment involving refining and marketing assets, the Company evaluates its properties when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events, which include projections of future margins, future capital expenditures and future operating expenses. Future marketing or operating decisions, such as closing or selling certain assets, and future regulatory or tax changes could also impact the Company s conclusion about potential asset impairment. Although the Company does not believe it had any significant properties with carrying values that were impaired at December 31, 2006, 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 on refining and marketing sales 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 future 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, PM 311/312, P, L and M in Malaysia, exploration licenses in the Republic of Congo and certain basis differences in the U.K. due to management s belief that these assets cannot be deemed to be realizable with any degree of confidence at this time. The Company occasionally is challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in its various income tax returns. Although the Company believes that it has adequate accruals for matters not resolved with various taxing authorities, gains or losses could occur in future years from changes in estimates or resolution of outstanding matters.

Accounting for retirement and postretirement benefit plans Murphy Oil and certain of its subsidiaries maintain defined benefit retirement plans covering most of its full-time employees. The Company also sponsors health care and life insurance benefit plans covering most retired U.S. employees. The expense associated with these plans is determined by management based on a number of assumptions and with consultation assistance from qualified third-party actuaries. The most important of these assumptions for the retirement plans involve the discount rate used to measure future plan obligations and the expected long-term rate of return on plan assets. For the retiree medical and insurance plans, the most important assumptions are the discount rate for future plan obligations and the health care

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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.

Based on higher bond yields during 2006, the Company has increased the primary plans discount rate from 5.70% in 2006 to 6.00% in 2007 and beyond. Although the Company presently assumes a return on plan assets of 7.00% 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 Company s normal annual retirement and postretirement plan expenses are estimated to increase slightly in 2007 compared to 2006 as the effects from a growing employee base will not fully offset the effects of a higher discount rate. In 2006, the Company paid $7.7 million into various retirement plans and $4.4 million into postretirement plans. In 2007, the Company is expecting to fund payments of approximately $7.1 million into various retirement plans and $4.3 million for postretirement plans. The Company could be required to make additional and more significant funding payments to retirement plans in future years. Future required payments and the amount of liabilities recorded on the balance sheet associated with the plans could be unfavorably affected if the discount rate declines, the actual return on plan assets falls below the assumed 7.0%, or the health care cost trend rate increase is higher than expected. As described above, the Company s retirement and postretirement expenses are sensitive to certain assumptions, primarily related to discount rates and assumed return on plan assets. A 0.5% decline in the discount rate would increase 2007 annual retirement and postretirement expenses by $2.0 million and $0.5 million, respectively, and a 0.5% decline in the assumed rate of return on plan assets would increase 2007 retirement expense by $1.1 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 2006 under such contractual obligations and arrangements are shown below.

	Amount of Obligation				
(Millions of dollars)	**Total**	**2007**	**2008-2010**	**2011-2012**	**After 2012**
Total debt including current maturities	$ 844.7	4.5	7.1	235.0	598.1
Operating leases	611.6	46.6	130.9	72.8	361.3
Purchase obligations	1,515.3	886.8	445.0	59.1	124.4
Other long-term liabilities	391.6	21.3	70.8	30.8	268.7
Total	$ 3,363.2	959.2	653.8	397.7	1,352.5

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 after 2006 by the Company prior to completion of the FPSO construction period totaling $6.0 million have been included in the contractual obligation table above in 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 addition, the Company has entered into an agreement, subject to successful completion of construction, to lease a production facility for the Thunder Hawk field in Mississippi Canyon Block 734. No amounts are payable by the Company prior to the successful completion of construction of this facility.

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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, 2006 that expire in future periods is shown below.

		Amount of Commitment			
(Millions of dollars)	Total	2007	2008-2010	2011-2012	After 2012
Financial guarantees	$ 8.5		2.6		5.9
Letters of credit	176.9	155.1	21.8		
Total	$ 185.4	155.1	24.4		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 2006 involves 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. Through 2006, actual production from the Medusa field has exceeded the contractual minimum volumes. The Company has a contract to purchase hydrogen for the Meraux refinery through 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 on the previous page.

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 2005 and 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 2007 was prepared during the fall of 2006 and based on this budget capital expenditures are expected to increase over 2006. Capital expenditures in 2007 are projected to total $1.9 billion. Of this amount, $1.6 billion or about 83%, is allocated for the exploration and production program. Geographically, E&P capital is spread approximately as follows: 17% for the United States, 56% for Malaysia, 12% for Canada and 15% for all other areas. Spending in the U.S. is primarily associated with continued development of producing deepwater fields and the Thunder Hawk field, which is anticipated to start-up in mid-2009, as well as for the Company s Gulf of Mexico exploration program. In Malaysia, the majority of the spending is for continued development of the Kikeh field in Block K, where first oil is anticipated in the second half of 2007, and for development of natural gas fields in Blocks SK 309 and 311 offshore Sarawak where first production is anticipated in the first half of 2009. Spending in the Republic of Congo includes early development costs for the Azurite Marine discovery offshore. Refining and marketing expenditures in 2007 should be about $329 million of which almost 90% is allocated for the U.S. budget, which includes funds for construction of additional retail gasoline stations at Wal-Mart Supercenters and other locations and real estate acquisitions near the Meraux refinery as part of the settlement of the oil spill litigation. Capital and other expenditures are routinely reviewed and planned capital expenditures may be adjusted to reflect differences between budgeted and actual cash flow during 2007. 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 2007, primarily in Malaysia at the Kikeh field in Block K and the gas fields in Sarawak, using available credit facilities. Most other funding is anticipated to be generated from operating cash flow. The Company forecasts an increase in long-term debt of approximately $800 million in 2007. 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 2007, oil prices weakened compared to prices experienced throughout most of 2006. These oil prices, in addition to gas prices, remained close to or above the prices used in the Company s 2007 budget. Through early 2007, margins for the Company s refining and marketing operations were below amounts included in the Company s 2007 budget.

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The Company currently expects production in 2007 to average between 95,000 and 105,000 barrels of oil equivalent per day. A key assumption in projecting the level of 2007 Company production is the anticipated start-up of oil production at the Kikeh field in Malaysia in the last half of 2007. The Kikeh field will ramp up production throughout 2008. In addition, continued reliability of facilities at significant non-operated fields such as Syncrude, Hibernia and Terra Nova are necessary to achieve the anticipated 2007 production levels.

Forward-Looking Statements

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

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to market risks associated with interest rates, prices of crude oil, natural gas and petroleum products, and foreign currency exchange rates. As described in Note A to the consolidated financial statements, Murphy makes limited use of derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions. There were no derivative instruments in place at December 31, 2006 to hedge market risks for commodity prices, interest rates or foreign exchange rates.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages F-1 through F-42, which follow page 41 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, 2006. 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, 2006 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 2006 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

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Item 9B. OTHER INFORMATION

None

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Certain information regarding executive officers of the Company is included on page 11 of this Form 10-K report. Other information required by this item is incorporated by reference to the Registrant s definitive Proxy Statement for the Annual Meeting of Stockholders on May 9, 2007 under the captions Election of Directors and Committees .

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

Item 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to Murphy s definitive Proxy Statement for the Annual Meeting of Stockholders on May 9, 2007 under the captions Compensation Discussion and Analysis and Compensation of Directors, and in various compensation schedules.

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

Information required by this item is incorporated by reference to Murphy s definitive Proxy Statement for the Annual Meeting of Stockholders on May 9, 2007 under the captions Security Ownership of Certain Beneficial Owners, Security Ownership of Management, and Equity Compensation Plan Information.

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

Information required by this item is incorporated by reference to Murphy s definitive Proxy Statement for the Annual Meeting of Stockholders on May 9, 2007 under the caption Election of Directors .

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by this item is incorporated by reference to Murphy s definitive Proxy Statement for the Annual Meeting of Stockholders on May 9, 2007 under the caption Audit Committee Report.

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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 7, 2007	Exhibit 3.2 of Murphy s Form 8-K dated February 12, 2007
4	Instruments Defining the Rights of Security Holders. Murphy is party to several long-term debt instruments in addition to those in Exhibits 4.1 and 4.2, none of which authorizes securities exceeding 10% of the total consolidated assets of Murphy and its subsidiaries. Pursuant to Regulation S-K, item 601(b), paragraph 4(iii)(A), Murphy agrees to furnish a copy of each such instrument to the Securities and Exchange Commission upon request.	
4.1	Form of Second Supplemental Indenture between Murphy Oil Corporation and SunTrust Bank, as Trustee	Exhibit 4.1 of Murphy s Form 8-K report filed May 3, 2002 under the Securities Exchange Act of 1934
4.2	Form of Indenture and Form of Supplemental Indenture between Murphy Oil Corporation and SunTrust Bank, as Trustee	Exhibit 4.2 of Murphy s Form 10-K report for the year ended December 31, 2004
4.3	Rights Agreement dated as of December 6, 1989 between Murphy Oil Corporation and Harris Trust Company of New York, as Rights Agent	Exhibit 4.3 of Murphy s Form 10-K report for the year ended December 31, 2004
4.4	Amendment No. 1 dated as of April 6, 1998 to Rights Agreement dated as of December 6, 1989 between Murphy Oil Corporation and Harris Trust Company of New York, as Rights Agent	Exhibit 4.4 of Murphy s Form 10-K report for the year ended December 31, 2004
4.5	Amendment No. 2 dated as of April 15, 1999 to Rights Agreement dated as of December 6, 1989 between Murphy Oil Corporation and Harris Trust Company of New York, as Rights Agent	Exhibit 4.5 of Murphy s Form 10-K report for the year ended December 31, 2004
10.1	1992 Stock Incentive Plan as amended May 14, 1997, December 1, 1999, May 14, 2003 and December 7, 2005	Exhibit 10.1 of Murphy s Form 10-K report for the year ended December 31, 2005
*10.2	Employee Stock Purchase Plan as amended May 10, 2000	
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

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

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

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SIGNATURES

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

MURPHY OIL CORPORATION

By:	CLAIBORNE P. DEMING Claiborne P. Deming, President	Date:	March 1, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on March 1, 2007 by the following persons on behalf of the registrant and in the capacities indicated.

WILLIAM C. NOLAN JR. William C. Nolan Jr., Chairman and Director	IVAR B. RAMBERG Ivar B. Ramberg, Director
CLAIBORNE P. DEMING Claiborne P. Deming, President and Chief Executive Officer and Director (Principal Executive Officer)	NEAL E. SCHMALE Neal E. Schmale, Director
FRANK W. BLUE Frank W. Blue, Director	DAVID J.H. SMITH David J.H. Smith, Director
GEORGE S. DEMBROSKI George S. Dembroski, Director	CAROLINE G. THEUS Caroline G. Theus, Director
ROBERT A. HERMES Robert A. Hermes, Director	KEVIN G. FITZGERALD Kevin G. Fitzgerald, Senior Vice President and Chief Financial Officer (Principal Financial Officer)
JAMES V. KELLEY James V. Kelley, Director	JOHN W. ECKART John W. Eckart Vice President and Controller (Principal Accounting Officer)
R. MADISON MURPHY R. Madison Murphy, Director	

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REPORT OF MANAGEMENT CONSOLIDATED FINANCIAL STATEMENTS

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

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

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of Murphy Oil Corporation:

We have audited the accompanying consolidated balance sheets of Murphy Oil Corporation and subsidiaries as of December 31, 2006 and 2005, 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, 2006. 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, 2006 and 2005, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note B to the consolidated financial statements, effective January 1, 2006, the Company changed its method of accounting for share-based payments. As also discussed in Note B to the consolidated financial statements, effective December 31, 2006, the Company changed its accounting for defined benefit pension and other postretirement plans.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Murphy Oil Corporation s internal control over financial reporting as of December 31, 2006, 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 1, 2007 expressed an unqualified opinion on management s assessment of, and the effective operation of, internal control over financial reporting.

Houston, Texas

March 1, 2007

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REPORT OF MANAGEMENT   INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Management has conducted an evaluation of the effectiveness of our internal control over financial reporting based on the criteria set forth in *Internal Control   Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation management concluded that our internal control over financial reporting was effective as of December 31, 2006.

Our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 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, 2006, 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, 2006, 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, 2006, 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, 2006 and 2005, 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, 2006, and our report dated March 1, 2007, expressed an unqualified opinion on those consolidated financial statements.

Houston, Texas

March 1, 2007

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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)***	**2006**	**2005**	**2004**
Revenues			
Sales and other operating revenues	**$ 14,279,325**	11,680,079	8,299,147
Gain on sale of assets	**9,388**	175,140	69,594
Interest and other income (loss)	**18,674**	21,932	(8,902)
Total revenues	**14,307,387**	11,877,151	8,359,839
Costs and Expenses			
Crude oil and product purchases	**11,214,235**	8,783,042	6,153,413
Operating expenses	**1,103,217**	848,647	736,057
Exploration expenses, including undeveloped lease amortization	**219,238**	232,400	164,227
Selling and general expenses	**228,512**	158,889	132,329
Depreciation, depletion and amortization	**384,063**	396,875	321,446
Net costs associated with hurricanes	**109,244**	66,770	3,350
Accretion of asset retirement obligations	**10,921**	9,704	10,017
Interest expense	**52,549**	47,304	56,224
Interest capitalized	**(43,073)**	(38,539)	(22,160)
Minority interest	**56**		
Total costs and expenses	**13,278,962**	10,505,092	7,554,903
Income from continuing operations before income taxes	**1,028,425**	1,372,059	804,936
Income tax expense	**390,146**	534,156	308,541
Income from continuing operations	**638,279**	837,903	496,395
Income from discontinued operations, net of tax		8,549	204,920
Net Income	**$ 638,279**	846,452	701,315
Income per Common Share Basic			
Income from continuing operations	**$ 3.43**	4.54	2.69
Income from discontinued operations		.05	1.12
Net Income Basic	**$ 3.43**	4.59	3.81
Income per Common Share Diluted			
Income from continuing operations	**$ 3.37**	4.46	2.65
Income from discontinued operations		.05	1.10
Net Income Diluted	**$ 3.37**	4.51	3.75
Average Common shares outstanding basic	**186,105,086**	184,354,552	183,972,642
Average Common shares outstanding diluted	**189,158,411**	187,889,378	186,887,022

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)***	**2006**	**2005**
Assets		
Current assets		
Cash and cash equivalents	**$ 543,390**	585,333
Accounts receivable, less allowance for doubtful accounts of $10,408 in 2006 and $14,508 in 2005	**995,089**	865,155
Inventories, at lower of cost or market		
Crude oil and blend stocks	**73,696**	83,265
Finished products	**224,469**	146,753
Materials and supplies	**112,912**	84,937
Prepaid expenses	**136,674**	33,239
Deferred income taxes	**20,861**	40,264
Total current assets	**2,107,091**	1,838,946
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $2,872,293 in 2006 and $2,459,022 in 2005	**5,106,282**	4,374,229
Goodwill	**44,057**	44,206
Deferred charges and other assets	**188,297**	111,130
Total assets	**$ 7,445,727**	6,368,511
Liabilities and Stockholders Equity		
Current liabilities		
Current maturities of long-term debt	**$ 4,466**	4,490
Notes payable	**2,659**	
Accounts payable	**1,008,597**	987,236
Income taxes payable	**63,003**	105,884
Other taxes payable	**151,435**	113,743
Other accrued liabilities	**80,945**	75,655
Total current liabilities	**1,311,105**	1,287,008
Notes payable	**833,126**	597,926
Nonrecourse debt of a subsidiary	**7,149**	11,648
Deferred income taxes	**581,920**	614,091
Asset retirement obligations	**237,875**	176,823
Accrued major repair costs	**71,229**	55,350
Deferred credits and other liabilities	**327,307**	164,675
Minority interest	**23,340**	
Stockholders equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued		
Common Stock, par $1.00, authorized 450,000,000 shares at December 31, 2006 and 2005, issued 187,691,508 shares at December 31, 2006 and 186,828,618 shares at December 31, 2005	**187,692**	186,829
Capital in excess of par value	**454,860**	437,963
Retained earnings	**3,284,391**	2,744,274
Accumulated other comprehensive income	**128,843**	131,324
Unamortized restricted stock awards		(16,410)
Treasury stock	**(3,110)**	(22,990)
Total stockholders equity	**4,052,676**	3,460,990

Total liabilities and stockholders equity	**$ 7,445,727**	6,368,511

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

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(Thousands of dollars)*	2006	2005	2004*
Operating Activities			
Net income	$ **638,279**	846,452	701,315
Income from discontinued operations		(8,549)	(204,920)
Income from continuing operations	**638,279**	837,903	496,395
Adjustments to reconcile income from continuing operations to net cash provided by operating activities			
Depreciation, depletion and amortization	**384,063**	396,875	321,446
Provisions for major repairs	**27,693**	35,020	30,208
Expenditures for major repairs and asset retirements	**(16,104)**	(31,919)	(18,587)
Dry hole costs	**111,044**	125,992	110,866
Amortization of undeveloped leases	**22,466**	22,819	16,415
Accretion of asset retirement obligations	**10,921**	9,704	10,017
Deferred and noncurrent income tax charges	**29,508**	40,755	106,159
Pretax gains from disposition of assets	**(9,388)**	(175,140)	(69,594)
Net increase in noncash operating working capital	**(255,970)**	(49,413)	(20,053)
Other operating activities net	**20,190**	4,117	51,785
Net cash provided by continuing operations	**962,702**	1,216,713	1,035,057
Net cash provided by discontinued operations		8,549	61,961
Net cash provided by operating activities	**962,702**	1,225,262	1,097,018
Investing Activities			
Property additions and dry hole costs	**(1,191,670)**	(1,246,242)	(938,449)
Proceeds from sale of property, plant and equipment	**23,843**	172,653	60,404
Proceeds from maturity of investment securities		17,892	
Purchase of investment securities			(17,892)
Other investing activities net	**(10,839)**	(9,943)	(840)
Investing activities of discontinued operations			
Sales proceeds			582,973
Other			(9,730)
Net cash required by investing activities	**(1,178,666)**	(1,065,640)	(323,534)
Financing Activities			
Additions to notes payable	**237,658**		
Reductions of notes payable	**(14)**	(46,386)	(454,178)
Additions to nonrecourse debt of a subsidiary			30
Reductions of nonrecourse debt of a subsidiary	**(4,667)**	(4,193)	(40,829)
Proceeds from exercise of stock options and employee stock purchase plans	**24,864**	26,513	3,156
Excess tax benefits related to exercise of stock options	**11,756**		
Cash dividends paid	**(98,162)**	(83,198)	(78,205)
Other financing activities net		(1,053)	
Net cash provided (required) by financing activities	**171,435**	(108,317)	(570,026)
Effect of exchange rate changes on cash and cash equivalents	**2,586**	(1,497)	79,642
Net increase (decrease) in cash and cash equivalents	**(41,943)**	49,808	283,100

Cash and cash equivalents at January 1	**585,333**	535,525	252,425
Cash and cash equivalents at December 31	**$ 543,390**	585,333	535,525

* Revised to reconcile net cash provided by operating activities to net income. Amounts presented in 2004 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)***	**2006**	**2005**	**2004**
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 2006 and 200,000,000 shares at December 31, 2004, issued 187,691,508 shares at December 31, 2006, 186,828,618 shares at December 31, 2005 and 94,613,379 shares at December 31, 2004			
Balance at beginning of year	$ **186,829**	94,613	94,613
Exercise of stock options	**863**		
Two-for-one stock split effective June 3, 2005		92,216	
Balance at end of year	**187,692**	186,829	94,613
Capital in Excess of Par Value			
Balance at beginning of year	**437,963**	511,045	504,809
Exercise of stock options, including income tax benefits	**23,956**	1,582	738
Restricted stock transactions and other	**(1,390)**	16,407	4,610
Amortization, forfeitures and other	**10,180**		
Sale of stock under employee stock purchase plans	**561**	1,145	888
Reclassification from Unamortized Restricted Stock Awards upon adoption of SFAS No. 123R	**(16,410)**		
Two-for-one stock split effective June 3, 2005		(92,216)	
Balance at end of year	**454,860**	437,963	511,045
Retained Earnings			
Balance at beginning of year	**2,744,274**	1,981,020	1,357,910
Net income for the year	**638,279**	846,452	701,315
Cash dividends $.525 per share in 2006, $.45 per share in 2005 and $.425 per share in 2004	**(98,162)**	(83,198)	(78,205)
Balance at end of year	**3,284,391**	2,744,274	1,981,020
Accumulated Other Comprehensive Income			
Balance at beginning of year	**131,324**	134,509	65,246
Foreign currency translation gains, net of income taxes	**36,016**	18,060	79,073
Cash flow hedging gains (losses), net of income taxes	**13,459**	(18,041)	(4,876)
Minimum pension liability adjustments, net of income taxes	**(819)**	(3,204)	(4,934)
Adjustment to initially apply SFAS No. 158, net of income taxes	**(51,137)**		
Balance at end of year	**128,843**	131,324	134,509
Unamortized Restricted Stock Awards			
Balance at beginning of year	**(16,410)**	(4,738)	
Reclassification to Capital in Excess of Par Value upon adoption of SFAS No. 123R	**16,410**		
Stock awards		(16,344)	(4,756)
Amortization, forfeitures and other		4,672	18
Balance at end of year		(16,410)	(4,738)
Treasury Stock			

Balance at beginning of year	**(22,990)**	(67,293)	(71,695)
Exercise of stock options	**13,345**	38,790	1,568
Sale of stock under employee stock purchase plans	**737**	1,182	617
Awarded restricted stock, net of forfeitures	**5,798**	4,331	2,217
Balance at end of year 119,308 shares of Common Stock in 2006, 881,940 shares in 2005 and 2,578,002 shares in 2004	**(3,110)**	(22,990)	(67,293)
Total Stockholders Equity	**$ 4,052,676**	3,460,990	2,649,156

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)***	**2006**	**2005**	**2004**
Net income	**$ 638,279**	846,452	701,315
Other comprehensive income (loss), net of tax			
Cash flow hedges			
Net derivative gains (losses)	**(5,154)**	(15,670)	8,022
Reclassification to income	**18,613**	(2,371)	(12,898)
Total cash flow hedges	**13,459**	(18,041)	(4,876)
Net gain from foreign currency translation	**36,016**	18,060	79,073
Minimum pension liability adjustments	**(819)**	(3,204)	(4,934)
Other comprehensive income (loss)	**48,656**	(3,185)	69,263
Comprehensive Income	**$ 686,935**	843,267	770,578

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

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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. For consolidated subsidiaries that are less than wholly owned, the minority interest is reflected in the balance sheet as a liability. Undivided interests in oil and gas joint ventures 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. Merchandise revenues are recorded at the point of sale. Revenues from the production of oil and natural gas properties in which Murphy shares an undivided interest with other producers are recognized based on the actual volumes sold by the Company during the period. Gas imbalances occur when the Company s actual sales differ from its entitlement under existing working interests. The Company records a liability for gas imbalances when it has sold more than its working interest of gas production and the estimated remaining reserves make it doubtful that partners can recoup their share of production from the field. At December 31, 2006 and 2005, the liabilities for natural gas balancing were immaterial. Excise taxes collected on sales of refined products and remitted to governmental agencies are not included in revenues or in costs and expenses.

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

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

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

PROPERTY, PLANT AND EQUIPMENT The Company uses the successful efforts method to account for exploration and development expenditures. Leasehold acquisition costs are capitalized. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties. Costs of undeveloped leases are generally expensed over the life of the leases. Exploratory well costs are capitalized pending determination about whether proved reserves have been found. In certain cases, a determination of whether a drilled exploratory well has found proved reserves can not be made immediately. This is generally due to the need for a major capital expenditure to produce and/or evacuate the hydrocarbon(s) found. The determination of whether to make such a capital expenditure is usually dependent on whether further exploratory wells find a sufficient quantity of additional reserves. Using guidance issued in FASB Position 19-1, Accounting for Suspended Well Costs, which became effective in April 2005, the Company continues to capitalize exploratory well costs in Property, Plant and Equipment when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The Company reevaluates its capitalized drilling costs at least annually to ascertain whether drilling costs continue to qualify for ongoing capitalization. Other exploratory costs, including geological and geophysical costs, are charged to expense as incurred. Development costs, including unsuccessful development wells, are capitalized.

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

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

Depreciation and depletion of producing oil and gas properties is recorded based on units of production. Unit rates are computed for unamortized exploration drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. Asset retirement costs are amortized over proved reserves using the units of production method. As more fully described on page F-34 of this Form 10-K report, proved reserves are estimated by the Company s engineers and are subject to future revisions based on availability of additional information. Refineries and certain marketing facilities are depreciated primarily using the composite straight-line method with depreciable lives ranging from 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 four to five year intervals at the Company s three refineries. Turnarounds for coking units at Syncrude Canada Ltd. are scheduled at intervals of two to three years. Turnaround work associated with various other less significant units at the Company s refineries and Syncrude will 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 which are included in Operating Expenses in the income statement. Future major repair costs are estimated by the Company s engineers. Actual turnaround 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 current period. All other maintenance and repairs are expensed. Renewals and betterments are capitalized. As more fully described in Note B, effective January 1, 2007, the Company will change its method of accounting for turnarounds. The Company will then defer actual turnaround costs as they are incurred and expense such costs using a monthly charge to expense.

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.

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GOODWILL Goodwill is recorded in an acquisition when the purchase price exceeds the fair value of net assets acquired. All goodwill recorded at December 31, 2006 and 2005 arose from the purchase of Beau Canada Exploration Ltd. by the Company s wholly owned Canadian subsidiary in 2000. In accordance with SFAS No. 142, Goodwill and Other Intangible Assets, goodwill is not amortized. SFAS No. 142 requires an annual assessment of recoverability of the carrying value of goodwill. The Company assesses goodwill recoverability at each year-end by comparing the fair value of net assets for conventional oil and natural gas properties in Canada with the carrying value of these net assets including goodwill. The fair value of the conventional oil and natural gas reporting unit is determined using the expected present value of future cash flows. The change in the carrying value of goodwill during 2006 was caused by a change in the foreign currency translation rate between years. Based on its assessment of the fair value of its Canadian conventional oil and natural gas operations, the Company believes the recorded value of goodwill is not impaired at December 31, 2006. 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 Nos. 138 and 149. The fair value of a derivative instrument is recognized as an asset or liability in the Company s Consolidated Balance Sheet. Upon entering into a derivative contract, the Company may designate the derivative as either a fair value hedge or a cash flow hedge, or decide that the contract is not a hedge, and thenceforth, recognize changes in the fair value of the contract in earnings. The Company documents the relationship between the derivative instrument designated as a hedge and the hedged items as well as its objective for risk management and strategy for use of the hedging instrument to manage the risk. Derivative instruments designated as fair value or cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. The Company assesses at inception and on an ongoing basis whether a derivative instrument used as a hedge is highly effective in offsetting changes in the fair value or cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting. Changes in the fair value of a qualifying fair value hedge are recorded in earnings along with the gain or loss on the hedged item. Changes in the fair value of a qualifying cash flow hedge are recorded in other comprehensive income until the hedged item is recognized in earnings. When the income effect of the underlying cash flow hedged item is recognized in the Statement of Income, the fair value of the associated cash flow hedge is reclassified from other comprehensive income into earnings. Ineffective portions of a cash flow 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 all potentially dilutive Common shares.

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

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

Note B   New Accounting Principles and Recent Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of SFAS Nos. 87, 88, 106 and 132R. This statement requires the Company to recognize in its consolidated balance sheet the overfunded or underfunded status of its defined benefit plans as an asset or liability and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This statement also requires that the Company measure the funded status of a plan as of December 31 rather than September 30 as previously permitted. The Company implemented this statement for the year ended December 31, 2006, except for the transition to a year-end measurement date which will occur in 2007. Refer to Note J for further information.

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

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

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. This statement was adopted by the Company on January 1, 2006 and it did not have a significant impact on the Company s 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 was applied to new arrangements entered into beginning April 1, 2006 and was applied to all inventory transactions that were completed after December 15, 2006 for arrangements entered into prior to March 15, 2006. The adoption of this consensus in 2006 did not have a significant impact on the Company s financial statements.

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

In September 2006, the FASB issued FSP AUG AIR-1 which prohibits, effective January 1, 2007, the use of the accrue-in-advance method of accounting for planned major maintenance activities as historically used by the Company. Accordingly, the Company will elect to use the deferral method for accounting for planned major maintenance activities beginning in 2007. Under the deferral method, the actual cost of each planned major maintenance activity is deferred and amortized through the next turnaround. Upon adoption in 2007 the Accrued Major Repair Costs reported on the Consolidated Balance Sheets will be replaced by a noncurrent asset representing the net unamortized major maintenance cost at the end of each reporting period and this accounting change is expected to cause a one-time increase to retained earnings of the Company. All prior periods financial statements presented will be retrospectively restated upon adoption of this new standard. The Company is currently evaluating this FSP and has preliminarily estimated the one-time after-tax credit to retained earnings to be approximately $70,000,000.

In June 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes. This interpretation clarifies the criteria for recognizing income tax benefits under FASB Statement No. 109, Accounting for Income Taxes, and requires additional financial statement disclosures about uncertain tax positions. The interpretation is effective beginning January 1, 2007. The Company is currently evaluating this interpretation and does not expect a significant impact on its financial statements.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This Statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This Statement applies under other accounting pronouncements that require or permit fair value measurements, and where applicable simplifies and codifies related guidance within GAAP and does not require any new fair value measurements. The Statement is effective for fiscal years beginning January 1, 2008. Provisions of the Statement are to be applied prospectively except in limited situations. The Company does not expect the initial adoption of this Statement to have a material impact on its financial statements.

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.

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The major assets and liabilities associated with the sale properties at the time of the sale in 2004 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	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 sale properties including gains on sale.

	Year Ended December 31,		
(Thousands of dollars)	**2006**	**2005**	**2004**
Revenues, including a pretax gain on sale of assets of $194,581 in 2004	$		274,568
Income before income tax expense			244,676
Income tax expense (benefit)		(8,549)	39,756

Note D Property, Plant and Equipment

	December 31, 2006		December 31, 2005	
(Thousands of dollars)	**Cost**	**Net**	**Cost**	**Net**
Exploration and production[1]	**$ 5,739,946**	**3,836,193**[2]	4,799,064	3,195,177[2]
Refining	**1,255,223**	**565,363**	1,176,421	546,610
Marketing	**909,150**	**655,463**	776,444	576,798
Corporate and other	**74,256**	**49,263**	81,322	55,644
	$ 7,978,575	**5,106,282**	6,833,251	4,374,229

1 Includes mineral rights as follows: **$ 199,739** **123,781** 193,065 129,873

2 Includes $27,010 in 2006 and $36,138 in 2005 related to administrative assets and support equipment.

On December 1, 2006, the Company exchanged its interest in the Rimbey field in western Canada for an 80% interest in the common stock of Berkana Energy Corporation (Berkana). The Company recorded a $9,909,000 pretax gain associated with the Rimbey exchange. The transaction was accounted for as a reverse acquisition and the 20% interest of Berkana held by its other shareholders has been reported as Minority Interest in the Consolidated Balance Sheet. Murphy recorded 20% of Berkana s pretax results of operations as Minority Interest in the Consolidated Income Statement subsequent to the transaction in December 2006. The pretax loss from sale of other assets in 2006 was $521,000.

During 2005 and 2004, the Company sold certain oil and gas properties and other assets and recorded before tax gains of $175,140,000 in 2005 and $69,594,000 in 2004. 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.

The FASB issued FSP 19-1 to provide guidance on accounting for exploratory well costs and to amend SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies. 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.

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At December 31, 2006, 2005 and 2004, the Company had total capitalized drilling costs pending the determination of proved reserves of $315,445,000, $275,256,000 and $106,105,000, respectively. The following table reflects the net changes in capitalized exploratory well costs during the three-year period ended December 31, 2006.

(Thousands of dollars)	**2006**	**2005**	**2004**
Beginning balance at January 1	**$ 275,256**	106,105	158,034
Additions to capitalized exploratory well costs pending the determination of proved reserves	**158,234**	169,151	94,048
Reclassifications to proved properties based on the determination of proved reserves	**(114,614)**		(125,211)
Capitalized exploratory well costs charged to expense or sold	**(3,431)**		(20,766)
Ending balance at December 31	**$ 315,445**	275,256	106,105

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)	**2006**	**2005**	**2004**
Exploratory well costs capitalized for one year or less	**$ 122,399**	172,596	93,956
Exploratory well costs capitalized for more than one year	**193,046**	102,660	12,149
Balance at December 31	**$ 315,445**	275,256	106,105
Number of projects with exploratory well costs that have been capitalized for more than one year	**11**	8	1

Of the $193,046,000 of exploratory well costs capitalized more than one year, $140,173,000 is in Malaysia, $40,635,000 is in Republic of Congo, $6,886,000 is in the U.S., and $5,352,000 is in Canada. In Malaysia either further appraisal or development drilling is planned and/or development studies/plans are in various stages of completion. In the Republic of Congo development plans are underway for the offshore Azurite field. In the U.S. drilling and development operations are planned, and in Canada a continuing drilling program is underway.

Note E Financing Arrangements

At December 31, 2006, the Company had a $1.04 billion committed credit facility with a major banking consortium that matures in June 2011. Between June 2010 and June 2011, the committed facility capacity is reduced to $982,500,000. Borrowings under this facility bear interest at prime or varying cost of fund options. Facility fees are due at varying rates on the commitment. At December 31, 2006 the Company had borrowed $235,000,000 under uncommitted credit lines, and had additional uncommitted amounts available of about $771,000,000 in a combination of U.S. and Canadian dollars. If necessary, the Company could convert borrowings under these uncommitted lines to the committed long-term credit facility outstanding through 2011. In addition, the Company has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of up to $650,000,000 in debt and/or equity securities.

Additionally, one of the Company s subsidiaries has a Cdn $25,000,000 revolving credit facility that matures in May 2007. There was US $2,659,000 of short-term notes payable drawn under this facility at December 31, 2006. Borrowings under this facility bear interest at prime plus varying cost of funds. All of the subsidiary s present and after-acquired property and assets (real, immovable and leasehold) are pledged as collateral. The net book value of these pledged assets was $99,817,000 as of December 31, 2006.

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Note F Long-term Debt

(Thousands of dollars)	December 31 2006	2005
Notes payable		
6.375% notes, due 2012, net of unamortized discount of $614 at December 31, 2006	**$ 349,386**	349,272
7.05% notes, due 2029, net of unamortized discount of $2,078 at December 31, 2006	**247,922**	247,829
Notes payable to banks, 5.55% to 5.60% at December 31, 2006	**235,000**	
Other, 6% to 8%, due 2007-2021	**825**	840
Total notes payable	**833,133**	597,941
Nonrecourse debt of a subsidiary		
Loans payable to Canadian government, interest free, payable in Canadian dollars, due 2007-2009	**11,608**	16,123
Total debt including current maturities	**844,741**	614,064
Current maturities	**(4,466)**	(4,490)
Total long-term debt	**$ 840,275**	609,574

Maturities for the four years after 2007 are: $4,468,000 in 2008, $2,690,000 in 2009, $1,000 in 2010 and $235,001,000 in 2011.

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

Note G Asset Retirement Obligations

The majority of the asset retirement obligations (ARO) recognized by the Company at December 31, 2006 and 2005 related to the estimated costs to dismantle and abandon its producing oil and gas properties and related equipment. A portion of the ARO relates to retail gasoline stations. The Company did not record an ARO for its refining and certain of its marketing assets because sufficient information is presently not available to estimate a range of potential settlement dates for the obligation. These assets are consistently being upgraded and are expected to be operational into the foreseeable future. In these cases, the obligation will be initially recognized in the period in which sufficient information exists to estimate the obligation.

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

(Thousands of dollars)	2006	2005
Balance at beginning of year	**$ 176,823**	201,932
Accretion expense	**10,921**	9,704
Liabilities incurred	**51,899**	13,438
Revisions of previous estimates	**1,463**	6,936
Liabilities settled	**(4,061)**	(56,066)
Changes due to translation of foreign currencies	**830**	879
Balance at end of year	**$ 237,875**	176,823

Liabilities settled in 2005 included approximately $47,554,000 of ARO assumed by the purchasing company upon the sales of oil and gas producing properties by the Company.

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

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Note H Income Taxes

The components of income from continuing operations before income taxes for each of the three years ended December 31, 2006 and income tax expense (benefit) attributable thereto were as follows.

(Thousands of dollars)	**2006**	**2005**	**2004**
Income from continuing operations before income taxes			
United States	**$ 332,817**	628,691	244,758
Foreign	**695,608**	743,368	560,178
	$ 1,028,425	1,372,059	804,936
Income tax expense (benefit) from continuing operations			
Federal Current	**$ 120,591**	165,019	22,446
Deferred	**(10,346)**	43,693	78,446
Noncurrent			(1,339)
	110,245	208,712	99,553
State	**1,865**	10,229	2,154
Foreign Current*	**241,353**	319,976	194,405
Deferred*	**36,683**	(5,333)	13,759
Noncurrent		572	(1,330)
	278,036	315,215	206,834
Total	**$ 390,146**	534,156	308,541

* Includes benefits of $37,554 in 2006 and $4,923 in 2004 for enacted reductions in federal and provincial tax rates in Canada. Tax expense in 2006 includes a charge of $17,845 for an enacted increase in income tax rate for exploration and production operations in the U.K.

Income tax benefits attributable to employee stock option transactions of $13,680,000 in 2006, $15,567,000 in 2005 and $553,000 in 2004 were included in Capital in Excess of Par Value in the Consolidated Balance Sheets. Income tax benefits (charges) of $(5,398,000) in 2006, $7,795,000 in 2005 and $2,712,000 in 2004 relating to derivatives were included in Accumulated Other Comprehensive Income (AOCI).

Total income tax expense in 2005 and 2004, including taxes associated with discontinued operations was $525,607,000 and $348,297,000, 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)	**2006**	**2005**	**2004**
Income tax expense based on the U.S. statutory tax rate	**$ 359,949**	480,221	281,727
Foreign income subject to foreign taxes at a rate different than the U.S. statutory rate	**23,141**	9,132	12,985
Canadian withholding tax and federal tax on dividend		8,520	45,863
State income taxes, net of federal benefit	**1,212**	6,649	1,400

Settlement of U.S. and foreign taxes		(21,849)	(5,545)
Changes in foreign tax rates	**(19,709)**		(4,923)
Increase in deferred tax asset valuation allowance related to foreign exploration expenditures	**20,147**	43,691	10,017
Recognition of deferred income tax benefit related to exploration and other expenses in Malaysia			(31,858)
Other, net	**5,406**	7,792	(1,125)
Total	**$ 390,146**	534,156	308,541

An analysis of the Company s deferred tax assets and deferred tax liabilities at December 31, 2006 and 2005 showing the tax effects of significant temporary differences follows.

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(Thousands of dollars)	**2006**	**2005**
Deferred tax assets		
Property and leasehold costs	**$ 219,467**	151,808
Liabilities for dismantlements and major repairs	**95,775**	82,765
Postretirement and other employee benefits	**87,703**	61,325
Foreign tax credit carryforwards	**41,043**	39,869
Other deferred tax assets	**71,796**	70,305
Total gross deferred tax assets	**515,784**	406,072
Less valuation allowance	**(205,809)**	(151,057)
Net deferred tax assets*	**309,975**	255,015
Deferred tax liabilities		
Property, plant and equipment	**(145,992)**	(73,509)
Accumulated depreciation, depletion and amortization	**(532,299)**	(541,564)
Foreign currency translation gains	**(69,679)**	(97,726)
Other deferred tax liabilities	**(107,650)**	(87,716)
Total gross deferred tax liabilities	**(855,620)**	(800,515)
Net deferred tax liabilities	**$ (545,645)**	(545,500)

* Includes deferred tax assets in Malaysia of $19,624 and $28,314 as of December 31, 2006 and 2005, 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. In the judgment of management at the present time, these tax assets are not likely to be realized. The foreign tax credit carryforwards expire in 2011, 2014 and 2015. The Company recorded deferred tax benefits of $31,858,000 in 2004 to recognize anticipated future tax benefits on exploration and other expenses related to Block K in Malaysia. The valuation allowance increased $54,752,000 in 2006, 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 its Canadian subsidiaries because such earnings are considered permanently invested in foreign countries. As of December 31, 2006, undistributed earnings of Canadian subsidiaries considered permanently invested were approximately $1,236,000,000. 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 $61,800,000. 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 and 2004, the Company recorded benefits to income of $21,849,000 and $5,545,000, respectively, from settlements of U.S. and foreign tax issues primarily related to prior years. Although the Company believes that recorded liabilities for unsettled issues are adequate, additional gains or losses could occur in future years from resolution of outstanding unsettled matters.

In October 2004 the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004 (the Act) became law. The FASB issued FASB Staff Position (FSP) 109-1 in December 2004 to provide guidance on the application of SFAS No. 109, Accounting for Income Taxes, to the provision within the Act that provides, beginning in 2005, a tax deduction on qualified production activities. The tax deduction phases in at 3% in 2005 and reaches 9% in 2010. FSP 109-1 concluded that the tax benefit for the deduction should be recognized as realized. This FSP was effective upon issuance and the Company applied it in computing U.S. income tax expense beginning in 2005. The Company recorded a tax benefit of $2,450,000 and $3,500,000 in 2006 and 2005, respectively, related to the Act.

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Note I Incentive Plans

The FASB issued Statement of Financial Accounting Standards (SFAS) No. 123 (revised 2004), Share-Based Payment (SFAS No. 123R), which replaced SFAS No. 123, Accounting for Stock-Based Compensation (SFAS No. 123), and superseded APB Opinion No. 25, Accounting for Stock Issued to Employees (APB No. 25). SFAS No. 123R requires that the cost resulting from all share-based payment transactions be recognized as an expense in the financial statements using a fair value-based measurement method over the periods that the awards vest. The Company adopted SFAS No. 123R as of January 1, 2006.

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 in the form of stock options (nonqualified or incentive), stock appreciation rights (SAR), and/or 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, the Stock Plan for Non-Employee Directors (2003 Director Plan) permits the issuance of restricted stock and stock options or a combination thereof to the Company s Directors. Amounts recognized in the financial statements with respect to share-based plans are as follows.

(Thousands of dollars)	**2006**	**2005**	**2004**
Compensation charged against income before income tax benefit	$ 18,814	15,633	3,279
Related income tax benefit recognized in income	6,112	5,449	1,140

As of December 31, 2006, there was $27,217,000 in compensation costs to be expensed over approximately the next two years related to unvested share-based compensation arrangements granted by the Company. Cash received from options exercised under all share-based payment arrangements for the years ended December 31, 2006, 2005 and 2004 was $24,864,000, $26,513,000 and $3,156,000, respectively. Total income tax benefits realized from tax deductions related to stock option exercises under share-based payment arrangements were $14,134,000, $16,073,000 and $1,007,000 for the years ended December 31, 2006, 2005 and 2004, respectively.

The Company had a history of issuing Treasury shares to satisfy share option exercises; however due to the limited number of remaining shares held in the Treasury, shares are now expected to be issued from authorized but unissued Common stock to satisfy future stock option exercises.

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 1992 Plan has had a term of 7 to 10 years, has been nonqualified, and has had an option price equal to or higher than FMV at date of grant. Under the 1992 Plan, one-half of each grant is exercisable after two years and the remainder after three years. Under the 2003 Director Plan, one-third of each grant is exercisable after each of the first three years.

Prior to adopting SFAS No. 123R, the Company used the intrinsic-value based method of accounting as prescribed by APB No. 25 and related interpretations to account for share-based compensation including stock options. Under this method, the Company accrued costs of restricted stock and any stock options deemed to be variable in nature over the vesting/performance period and adjusted such costs for changes in the fair market value of Common Stock. No compensation expense was recorded for fixed stock options since all option prices were equal to or greater than the fair market value of the Company s stock on the date of grant. Had the Company recorded compensation expense for stock options as prescribed by SFAS No. 123, net income and earnings per share for the years ended December 31, 2005 and 2004, would have been the pro forma amounts shown in the following table.

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

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

	2006	**2005**	**2004**
Fair value per option grant	**$ 17.53**	$ 11.79	$ 7.46
Assumptions			
Dividend yield	**0.90%**	1.25%	1.86%
Expected volatility	**30.00%**	26.00%	27.81%
Risk-free interest rate	**4.42%**	3.74%	3.24%
Expected life	**4.75 yrs.**	5.00 yrs.	5.00 yrs.

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

	Number of Shares	**Average Exercise Price**
Outstanding at December 31, 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
Granted FMV	787,500	57.32
Exercised	(1,374,827)	17.18
Forfeited	(345,500)	45.73
Outstanding at December 31,2006	7,481,810	25.41
Exercisable at December 31, 2004	5,372,120	$ 15.03
Exercisable at December 31, 2005	5,576,829	16.49
Exercisable at December 31, 2006	5,544,656	18.31

Additional information about stock options outstanding at December 31, 2006 is shown below.

Range of Exercise Prices per Option	**Options Outstanding** No. of Options	Avg. Life in Years	Aggregate Intrinsic Value	**Options Exercisable** No. of Options	Avg. Life in Years	Aggregate Intrinsic Value
$ 8.92 to $ 14.24	1,355,000	2.1	$ 51,754,000	1,355,000	2.1	$ 51,754,000
$15.11 to $ 23.58	3,696,750	4.9	118,530,000	3,696,750	4.9	118,530,000
$30.29 to $ 57.32	2,430,060	5.0	24,349,000	492,906	4.2	10,123,000

	7,481,810	4.4	$ 194,633,000	5,544,656	4.2	$ 180,407,000

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

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PERFORMANCE-BASED RESTRICTED STOCK Shares of restricted stock were granted under the Plan in certain years. Each grant will vest if the Company achieves specific objectives based on market conditions at the end of the three-year performance period. Additional shares may be awarded if objectives are exceeded, but some or all shares may be forfeited if objectives are not met. The market conditions generally include a measure of the Company s total shareholder return over the three-year period compared to an industry peer group of companies. During the performance period, a grantee receives dividends and may vote these shares, but shares are subject to transfer restrictions and are subject to forfeiture if a grantee terminates. In the event that the shares vest, the Company shall reimburse a grantee up to 50% of the fair market value of the restricted stock for personal income tax liability. Changes in performance-based restricted stock outstanding for each of the last three years are presented in the following table.

(Number of shares)	2006	2005	2004
Balance at beginning of year	**478,445**	157,000	
Granted	**265,750**	336,000	157,000
Forfeited	**(63,903)**	(14,555)	
Balance at end of year	**680,292**	478,445	157,000

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

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

	2006
Fair value per share at grant date	$ 37.33
Assumptions	
Expected volatility	26.30%
Risk-free interest rate	4.49%
Stock beta	0.955
Expected life	3.00 yrs.

The fair value of the Company s stock on the date of grant for the 2005 and 2004 awards was $45.23 and $30.21 per share, respectively.

TIME-LAPSE RESTRICTED STOCK Shares of restricted stock were granted to the Company s Directors under the 2003 Director Plan and vest on the third anniversary of the date of grant. The fair value of these awards was estimated based on the fair market value of the Company s stock on the date of grant, which was $57.32 per share in 2006, $45.23 per share in 2005 and $30.21 per share in 2004. Changes in time-lapse restricted stock outstanding for each of the periods are presented in the following table.

(Number of shares)	2006	2005	2004
Balance at beginning of year	**35,574**	12,624	
Granted	**20,568**	22,950	13,262
Forfeited			(638)
Balance at end of year	**56,142**	35,574	12,624

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 the end of the quarter at a price equal to 90% of the fair value of the stock as of the first day of the quarter. The ESPP will terminate on the earlier of the date that employees have purchased all 600,000 shares or June 30, 2007. Employee stock purchases under the ESPP were 28,280 shares at an average price of $45.88 per share in 2006, 33,425 shares at $43.30 per share in 2005, and 40,660 shares at $31.92 per share in 2004. At December 31, 2006, 121,205 shares remained available for sale under the ESPP. Compensation costs related to the ESPP are estimated based on the value of the 10% discount and the fair value of the option that provides for the refund of participant withholdings and amounted to $256,000 in 2006. The fair value per share of the ESPP was approximately $7.57 for the year ended December 31, 2006.

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

CASH AWARDS The Committee also administers the Company s incentive compensation plans, which provide for annual or periodic cash awards to officers, directors and key employees. These cash awards are generally determinable based on the Company achieving specific financial objectives. Compensation expense of \$14,862,000, \$17,634,000 and \$13,663,000 was recorded in 2006, 2005 and 2004, respectively, for these plans.

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.

The Company adopted the recognition and disclosure requirements of Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans at December 31, 2006. The following table presents the incremental effect of applying SFAS No. 158 on individual line items in the Consolidated Balance Sheet at December 31, 2006.

(Thousands of dollars)	Before Application of SFAS No. 158	SFAS No. 158 Adjustments	After Application of SFAS No. 158
Deferred charges and other assets	$ 180,129	8,168	188,297
Other accrued liabilities	80,743	202	80,945
Deferred income tax liabilities	609,987	(28,067)	581,920
Deferred credits and other liabilities	240,137	87,170	327,307
Accumulated other comprehensive income	179,980	(51,137)	128,843

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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, 2006 and 2005 and a statement of the funded status as of December 31, 2006 and 2005.

	Pension Benefits		Postretirement Benefits	
(Thousands of dollars)	**2006**	**2005**	**2006**	**2005**
Change in benefit obligation				
Obligation at January 1	**$ 388,018**	355,888	**71,224**	58,516
Service cost	**10,264**	9,099	**2,128**	1,906
Interest cost	**21,670**	20,478	**3,923**	3,749
Plan amendments	**7,752**	391		
Participant contributions	**47**	45	**818**	797
Actuarial loss	**6,782**	26,607	**954**	10,642
Exchange rate changes	**10,234**	(7,173)		
Benefits paid	**(18,916)**	(17,317)	**(5,467)**	(4,313)
Special termination benefits	**3,796**		**(1,044)**	
Other	**(249)**		**31**	(73)
Obligation at December 31	**429,398**	388,018	**72,567**	71,224
Change in plan assets				
Fair value of plan assets at January 1	**300,384**	268,632		
Actual return on plan assets	**16,887**	27,316		
Employer contributions	**7,675**	26,433	**4,360**	3,516
Participant contributions	**47**	45	**818**	797
Exchange rate changes	**7,410**	(4,485)		
Benefits paid	**(18,916)**	(17,317)	**(5,467)**	(4,313)
Other	**(273)**	(240)	**289**	
Fair value of plan assets at December 31	**313,214**	300,384		
Reconciliation of funded status				
Funded status at December 31	**(116,184)**	(87,634)	**(72,567)**	(71,224)
Unrecognized actuarial loss		105,430		31,845
Unrecognized transition asset		(4,123)		
Unrecognized prior service cost		4,860		(3,536)
Net plan asset (liability) recognized	**$ (116,184)**	18,533	**(72,567)**	(42,915)
Amounts recognized in the Consolidated Balance Sheets at December 31				
Deferred charges and other assets	**$ 16,813**	8,451		
Other accrued liabilities	**(4,215)**			
Deferred credits and other liabilities	**(128,782)**	(55,159)	**(72,567)**	(42,915)
Intangible asset		3,113		
Accumulated other comprehensive loss*		62,128		
Net plan asset (liability) recognized	**$ (116,184)**	18,533	**(72,567)**	(42,915)

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

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

Amounts recognized in accumulated other comprehensive income before reduction for associated deferred taxes at December 31, 2006 included:

(Thousands of dollars)	**Pension Benefits 2006**	**Postretirement Benefits 2006**
Net loss	**$ (106,640)**	**(30,118)**
Prior service (cost) credit	**(10,541)**	**3,108**
	$ (117,181)	**(27,010)**

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A minimum pension liability adjustment was required for certain of the Company s plans. After reductions for amounts charged to intangible assets, net of associated deferred income taxes, comprehensive income was reduced by charges of $819,000 in 2006, $3,204,000 in 2005 and $4,934,000 in 2004.

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

	Projected Benefit Obligations		Accumulated Benefit Obligations		Fair Value of Plan Assets	
(Thousands of dollars)	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**
Funded qualified plans where PBO exceeds fair value of plan assets	**$ 372,783**	341,125	**329,461**	299,582	**279,749**	252,632
Unfunded nonqualified and directors plans where PBO exceeds fair value of plan assets	**40,202**	30,715	**29,633**	23,049		
Unfunded postretirement plans	**72,567**	71,224	**72,567**	42,915		

The table that follows provides the components of net periodic benefit expense for each of the three years ended December 31, 2006.

	Pension Benefits			Postretirement Benefits		
(Thousands of dollars)	**2006**	**2005**	**2004**	**2006**	**2005**	**2004**
Service cost	**$ 10,264**	9,099	8,332	**2,128**	1,906	1,707
Interest cost	**21,670**	20,478	19,478	**3,923**	3,749	3,507
Expected return on plan assets	**(20,315)**	(19,092)	(18,620)			
Amortization of prior service cost	**1,929**	820	785	**(277)**	(277)	(277)
Amortization of transitional asset	**(490)**	(624)	(636)			
Recognized actuarial loss	**6,416**	5,916	4,554	**1,637**	1,595	1,347
	19,474	16,597	13,893	**7,411**	6,973	6,284
Special termination benefits expense	**4,748**					
Curtailment expense (benefit)	**594**			**(152)**		
Settlement gain			(1,069)			
Net periodic benefit expense	**$ 24,816**	16,597	12,824	**7,259**	6,973	6,284

Termination and curtailment expense in 2006 primarily related to the reorganization of the Company s U.S. exploration and production operation. A settlement gain in 2004 related to employee reductions associated with the sale of western Canadian conventional oil and gas properties.

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

	Pension Benefits		Postretirement Benefits	
(Thousands of dollars)	**2006**	**2005**	**2006**	**2005**
Benefit obligation at December 31	**$ 107,473**	92,500		
Fair value of plan assets at December 31	**98,072**	85,300		
Net plan liability recognized	**9,401**	5,289		
Net periodic benefit expense	**3,004**	1,594		

The following table provides the weighted-average assumptions used in the measurement of the Company s benefit obligations at December 31, 2006 and 2005 and net periodic benefit expense for the years 2006 and 2005.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits December 31		Postretirement Benefits December 31		Pension Benefits Year		Postretirement Benefits Year	
	2006	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**
Discount rate	**5.71%**	5.58%	**6.00%**	5.70%	**5.48%**	5.81%	**5.70%**	6.00%
Expected return on plan assets	**6.89%**	7.08%			**6.89%**	7.24%		
Rate of compensation increase	**4.46%**	4.06%			**4.09%**	4.06%		

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 anticipated future averages for the Company.

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The weighted average asset allocation for the Company s benefit plans at the annual measurement dates of September 30, 2006 and 2005 are presented in the following table.

	September 30	
	2006	**2005**
Equity securities	**52.3%**	56.3%
Debt securities	**44.0**	38.6
Cash	**3.7**	5.1
	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 weighted average expected return on plan assets was 6.89% in 2006 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 6.89% expected return was based on an expected average future equity securities return of 8.74% and a debt securities return of 5.41% and is net of average expected investment expenses of 0.42%. Over the last 10 years, the return on funded retirement plan assets has averaged 8.09%.

The Company currently expects during 2007 to make contributions of $5,088,000 to its domestic defined benefit pension plans, $1,990,000 to its foreign defined pension plans and $4,274,000 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
2007	$ 19,711	4,274
2008	20,223	4,560
2009	20,732	4,909
2010	21,423	5,242
2011	22,234	5,599
2012-2016	130,314	32,634

For purposes of measuring postretirement benefit obligations at December 31, 2006, the future annual rates of increase in the cost of health care were assumed to be 9.0% for 2007 decreasing each year to an ultimate rate of 5.0% in 2013 and thereafter.

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

(Thousands of dollars)	1% Increase	1% Decrease
Effect on total service and interest cost components of net periodic postretirement benefit expense for the year ended December 31, 2006	$ 1,075	(847)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 2006	10,786	(8,786)

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 postretirement benefit expense was $1,422,000, $1,410,000 and $1,000,000 lower during 2006, 2005 and 2004, respectively.

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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 and 6,604 shares in 2004. Amounts charged to expense for these U.S. and U.K. plans were $2,957,000 in 2006, $7,886,000 in 2005 and $4,895,000 in 2004.

Note K Financial Instruments and Risk Management

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

Natural Gas Fuel Price Risks The Company purchases natural gas as fuel at its Meraux, Louisiana and Superior, Wisconsin refineries, and as such, is subject to commodity price risk related to the purchase price of this gas. Murphy hedged the cash flow risk associated with the cost of a portion of the natural gas it purchased during the last three years by entering into financial contracts known as natural gas swaps with a notional volume during 2006 of 720,000 MMBTU (1 MMBTU = 1 million British Thermal Units). Other similar contracts covered a portion of 2005 and 2004 purchases. Under the natural gas swaps, the Company paid a fixed rate averaging $3.35 per MMBTU and received a floating rate in each month of settlement based on the average NYMEX price for the final three trading days of the month. Murphy has a risk management control system to monitor natural gas price risk attributable both to forecasted natural gas requirements and to Murphy s natural gas swaps. The control system involves using analytical techniques, including various correlations of natural gas purchase prices to future prices, to estimate the impact of changes in natural gas fuel prices on Murphy s cash flows. The fair value of the effective portions of the natural gas swaps and changes thereto was deferred in AOCI and was subsequently reclassified into Operating Expenses in the income statements in the periods in which the hedged natural gas fuel purchases occurred. For the three years ended December 31, 2006, the income (expense) effect from cash flow hedging ineffectiveness for these contracts was $(28,000), $1,021,000 and $472,000, respectively. During the years ended December 31, 2006, 2005 and 2004, the Company received approximately $2,791,000, $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 2006 and 2005 Canadian heavy oil production by entering into forward sale contracts covering a notional volume of approximately 4,000 barrels per day in 2006 and 2,000 barrels per day in 2005. In 2006, the Company paid the average of the posted price at the Hardisty terminal in Canada for each month and received a fixed price of $25.23 per barrel. In 2005, the Company paid the average Hardisty posted price and received $29.00 per barrel. Murphy has a risk management control system to monitor crude oil price risk attributable both to forecasted crude oil sales prices and to Murphy s hedging instruments. The control system involves using analytical techniques, including various correlations of crude oil sales prices to futures prices, to estimate the impact of changes in crude oil prices on Murphy s cash flows from the sale of light and heavy crude oil. The fair value of the effective portions of the crude oil sales price hedges and changes thereto was deferred in AOCI and was subsequently reclassified into Sales and Other Operating Revenues in the income statement in the periods in which the hedged crude oil sales occurred. During 2006, 2005 and 2004, earnings were increased by $160,000, $65,000 and $225,000, respectively, for cash flow hedging ineffectiveness on crude oil sales price hedges. During 2006 and 2005, the Company paid approximately $29,373,000 and $5,254,000, respectively, for settlement of maturing crude oil sales swaps.

There were no forecasted transactions being hedged as of December 31, 2006.

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FAIR VALUE The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2006 and 2005. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties. The table excludes cash and cash equivalents, trade accounts receivable, short-term notes payable, trade accounts payable and accrued expenses, all of which had fair values approximating carrying amounts. The fair value of current and long-term debt was estimated based on rates offered to the Company at that time for debt of the same maturities. The Company has off-balance sheet exposures relating to certain financial guarantees and letters of credit. The fair value of these, which represents fees associated with obtaining the instruments, was nominal.

	At December 31,			
	2006		2005	
(Thousands of dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Financial assets (liabilities):				
Natural gas fuel swaps	$		5,225	5,225
Crude oil sales swaps			(24,268)	(24,268)
Current and long-term debt	**(844,741)**	(878,227)	(614,064)	(664,231)

The 2005 carrying amounts of crude oil swaps and natural gas swaps in the preceding table were included in the 2005 Consolidated Balance Sheet in Accounts Receivable or Other Accrued Liabilities. Current and long-term debts at both year-ends are included under Current Maturities of Long-Term Debt, noncurrent 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, 2006. No difference existed between net income used in computing basic and diluted income per Common share for these years.

(Weighted-average shares outstanding)	**2006**	**2005**	**2004**
Basic method	**186,105,086**	184,354,552	183,972,642
Dilutive stock options	**3,053,325**	3,534,826	2,914,380

Diluted method	**189,158,411**	187,889,378	186,887,022

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Options to purchase 706,000 shares of Common stock at a weighted average share price of $57.32 were outstanding at year-end 2006 but were not included in the computation of diluted earnings per share because the incremental shares from assumed conversion were antidilutive. There were no antidilutive options for the 2005 and 2004 periods.

Note N Other Financial Information

INVENTORIES Inventories accounted for under the LIFO method totaled $214,810,000 and $157,255,000 at December 31, 2006 and 2005, respectively, and these amounts were $389,481,000 and $361,345,000 less than such inventories would have been valued using the FIFO method.

ACCUMULATED OTHER COMPREHENSIVE INCOME At December 31, 2006 and 2005, the components of Accumulated Other Comprehensive Income were as follows.

(Thousands of dollars)	**2006**	**2005**
Foreign currency translation gains, net of tax	**$ 221,738**	185,722
Cash flow hedge losses, net of tax		(13,459)
Pension liability adjustments, net of tax	**(92,895)**	(40,939)
Balance at end of year	**$ 128,843**	131,324

At December 31, 2006, components of the net foreign currency translation gain of $221,738,000 were gains of $39,927,000 for pounds sterling, $174,417,000 for Canadian dollars and $7,394,000 for other currencies. Foreign currency translation gains shown in the table are net of income taxes of $69,679,000 and $97,726,000 at year-end 2006 and 2005, respectively. Net gains (losses) from foreign currency transactions included in the Consolidated Statements of Income were $(8,000,000) in 2006, $102,000 in 2005 and $(26,613,000) in 2004. The pension liability adjustment increased in 2006 essentially due to adoption of SFAS No. 158 as described in Notes B and J.

The effect of SFAS Nos. 133/138, Accounting for Derivative Instruments and Hedging Activities, increased AOCI for the year ended December 31, 2006 by $13,459,000, net of $5,398,000 in income taxes, and income increased by $132,000 for the same period. For the year ended December 31, 2005, AOCI decreased by $18,041,000, net of $7,795,000 in income taxes, and income increased by $1,086,000. 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.

CASH FLOW DISCLOSURES Cash income taxes paid were $466,087,000, $586,544,000 and $184,950,000 in 2006, 2005 and 2004, respectively. Interest paid, net of amounts capitalized, was $7,270,000, $6,095,000 and $32,141,000 in 2006, 2005 and 2004, respectively.

Noncash operating working capital increased during each of the three years ended December 31, 2006 as follows.

(Thousands of dollars)	**2006**	**2005**	**2004**
Accounts receivable	**$ (128,004)**	(162,222)	(252,732)
Inventories	**(96,122)**	(19,110)	(25,335)
Prepaid expenses	**(103,435)**	12,532	(992)
Deferred income tax assets	**19,403**	(8,867)	(10,457)
Accounts payable and accrued liabilities	**95,069**	264,305	252,720
Current income tax liabilities	**(42,881)**	(136,051)	16,743
Net increase in noncash operating working capital from continuing operations	**$ (255,970)**	(49,413)	(20,053)

Note O Hurricane and Insurance Related Matters

In 2006 and 2005 the Company recorded pretax expenses, net of anticipated insurance recoveries, of $109,244,000 and $66,770,000, respectively, associated with hurricanes that occurred in the United States in 2005. The components of the 2006 costs included $107,410,000 at the Meraux refinery, including $49,500,000 for refinery repair costs not expected to be recovered due to certain coverage limits for the

Company s insurance policies; $5,909,000 for incremental insurance costs; $9,013,000 for other uninsured incremental expenses incurred; $18,000,000 for settlement of oil spill class action litigation; and $24,988,000 for depreciation and salaries while the refinery was temporarily idled prior to restarting in mid-2006. The components of the 2005 costs, all of which occurred in the second half of the year, included $22,945,000 for incremental insurance expenses; $15,493,000 for uninsured losses within the Company s insurance deductibles; $8,844,000 for voluntary costs for charitable donations related to hurricane relief efforts and additional employee salaries; and $19,488,000 for depreciation and salaries for the temporarily idled Meraux, Louisiana, refinery. In 2004 the Company reported pretax costs of $3,350,000 for uninsured losses within the Company s insurance deductibles. The costs for the respective periods are reported in Net Costs Associated With Hurricanes in the Consolidated Statements of Income. Total amounts receivable from insurers for hurricane-related matters were $263,182,000 at December 31, 2006, of which $220,348,000 was classified as current in the Consolidated Balance Sheet. The current receivable includes $152,000,000 related to the recently settled oil spill litigation expected to be recovered through insurance. Through 2006, the Company s refining and marketing operations received Hurricane Katrina insurance proceeds of $228,300,000, including $156,000,000 related to oil spill liabilities and $72,300,000 related to property damage incurred as a result of Hurricane Katrina. See Note Q for additional information regarding environmental and other contingencies relating to Hurricane Katrina.

The Company maintains insurance coverage related to losses of production and profits for occurrences such as storms, fires and other issues. During 2006 the Company s exploration and production operations recorded $15,700,000 in business interruption insurance recoveries relating to Hurricane Katrina in 2005, and $5,000,000 due to lost production at Terra Nova related to the mechanical failure of the main power generator. In 2005, the Company received insurance proceeds of $11,258,000 related to loss of production in the Gulf of Mexico associated with prior year Hurricanes Ivan and Lili. 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 production in the Gulf of Mexico associated with Hurricane Lili in 2002. These business interruption collections were reported in Sales and Other Operating Revenues in the Consolidated Statements of Income.

Note P Commitments

The Company leases land, gasoline stations and other facilities under operating leases. During the next five years, expected future rental payments under operating leases are approximately $46,634,000 in 2007; $45,223,000 in 2008; $43,441,000 in 2009; $42,181,000 in 2010; and $36,943,000 in 2011. Rental expense for noncancellable operating leases, including contingent payments when applicable, was $46,336,000 in 2006, $33,379,000 in 2005 and $27,943,000 in 2004.

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 for the next five years are $6,523,000 in 2007; $6,784,000 in 2008; $7,056,000 in 2009; $7,338,000 in 2010; and $7,631,000 in 2011. Base facility charges and hydrogen costs incurred in 2006, 2005 and 2004 totaled $23,903,000, $21,595,000 and $27,141,000, respectively. As a result of the refinery being shut down for several months following Hurricane Katrina, the Company notified the hydrogen supplier of a force majeure event. The hydrogen supply agreement permits the base facility charge to be suspended for the period under force majeure and the contract supply period to be extended for the same period, but in no event shall the extension of the supply period exceed 1,375 days. The Company completed repairs to its refinery and began purchasing hydrogen under this agreement within the period permitted in the contract. There were no base facility charges or hydrogen costs incurred for the last four months of 2005 and the first four months of 2006.

The Company has Operating and Production Handling Agreements providing for processing and production handling services for hydrocarbon production from certain fields in the Gulf of Mexico. These agreements require minimum annual payments for processing charges through 2013. Future required minimum payments for the next five years are $12,596,000 in 2007; $11,078,000 in 2008; $32,116,000 in 2009; and $18,844,000 in 2010 and 2011. In addition, the Company is required to pay additional amounts depending on the actual hydrocarbon quantities processed under the agreement. Processing and handling costs incurred were $27,007,000 in 2006, $24,297,000 in 2005 and $23,430,000 in 2004.

Additionally, the Company has a Reserved Capacity Service Agreement providing for the availability of needed crude oil storage capacity for certain oil fields through 2020. Under the agreement, the Company must make specified minimum payments monthly. Future required minimum annual payments are approximately $3,000,000 in 2007 through 2012. In addition, the Company is required to pay additional amounts depending on actual crude oil quantities under the agreement. Total payments under the agreement were $3,666,000 in 2006, $2,521,000 in 2005 and $2,390,000 in 2004.

In 2006, the Company committed to fund an educational assistance program known as the El Dorado Promise. Under this commitment, the Company will pay $5,000,000 per year from 2007 to 2016 to cover a specified amount of college tuition for eligible graduates of El Dorado High School in Arkansas. The first payment was made in January 2007. Based

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on SFAS 116, Accounting for Contributions Received and Contributions Made, the Company recorded a discounted liability of $38,700,000 in 2006 for this unconditional commitment. The liability was discounted at the Company s 10-year borrowing rate and the discounted liability will increase for accretion monthly with a corresponding charge to Selling and General Expense in the Consolidated Statement of Income.

Commitments for capital expenditures were approximately $922,600,000 at December 31, 2006, including $105,900,000 for costs to develop deepwater Gulf of Mexico fields, $555,200,000 for field development and future work commitments in Malaysia, $69,500,000 for exploration drilling and field development in the Republic of Congo and $18,100,000 for future work commitments on the Scotian Shelf offshore eastern Canada.

The Company has entered into contracts to hire various drilling rigs and associated equipment for periods beyond December 31, 2006. These rigs are primarily utilized for deepwater drilling operations in the Gulf of Mexico and Malaysia. Future commitments under these contracts, all of which expire by 2008, total $294,800,000. A significant portion of these costs are expected to be borne by other working interest owners as partners of the Company when the wells are drilled. These drilling costs are generally expected to be accounted for as capital expenditures as incurred during the contract periods.

Note Q Contingencies

The Company s operations and earnings have been and may be affected by various forms of governmental action both in the United States and throughout the world. Examples of such governmental action include, but are by no means limited to: tax increases and retroactive tax claims; 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 70 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 27 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.

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On September 9, 2005, a class action lawsuit was filed in federal court in the Eastern District of Louisiana seeking unspecified damages to the class comprised of residents of St. Bernard Parish caused by a release of crude oil at Murphy Oil USA, Inc. s (a wholly-owned subsidiary of Murphy Oil Corporation) Meraux, Louisiana, refinery as a result of flood damage to a crude oil storage tank following Hurricane Katrina. Additional class action lawsuits were consolidated with the first suit into a single action in the U.S. District Court for the Eastern District of Louisiana. In September 2006, the Company reached a settlement with class counsel and on October 10, 2006, the court granted preliminary approval of a class action Settlement Agreement. A Fairness Hearing was held January 4, 2007 and the court entered its ruling on January 30, 2007 approving the class settlement. The majority of the settlement of $330 million will be paid by insurance. The Company recorded an expense of $18 million in 2006 related to settlement costs not expected to be covered by insurance. As part of the settlement, all properties in the class area will receive a fair and equitable cash payment and will have residual oil cleaned. As part of the settlement, the Company will offer to purchase all properties in an agreed area adjacent to the west side of the Meraux refinery; these property purchases and associated remediation will be paid by the Company and are expected to total $55 million. Approximately 100 non-class action suits regarding the oil spill have been filed and remain pending; however, as part of its October 10, 2006, order, the court stayed these actions pending the settlement proceedings and further orders of the court. The Company believes that insurance coverage exists and it does not expect to incur significant costs associated with this litigation. Accordingly, the Company believes the ultimate resolution of the remaining litigation 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. The St. Bernard Parish action has since been removed to federal court where a class certification hearing is scheduled for June 24, 2007. 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 alleged 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. A trial concerning the 25% disputed interest and any remaining issues was held in the second quarter 2006 and on September 15, 2006 the Court of Queen s Bench of Alberta issued a ruling in the Company s favor. Predator did not appeal. Based on this ruling, approximately $15.9 million of previously disputed natural gas sales proceeds and associated interest thereon was recognized as income during the fourth quarter 2006.

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, 2006, the Company had contingent liabilities of

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$8,519,000 under a financial guarantee described in the following paragraph and $176,886,000 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 2008 and 2023. 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, 2006, 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, 2006 is shown below.

(Number of shares outstanding)	**2006**	**2005**	**2004**
At beginning of year	**185,946,678**	92,035,377	91,870,598
Stock options exercised	**1,374,827**	1,488,063	60,000
Employee stock purchase and thrift plans	**28,280**	45,344	23,632
Restricted stock awards, net of forfeitures	**222,415**	165,920	84,812
Two-for-one stock split effective June 3, 2005		92,215,239	
All other		(3,265)	(3,665)
At end of year	**187,572,200**	185,946,678	92,035,377

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

Note 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/or natural gas. The Company s refining and marketing segments are North America and the United Kingdom and each derives revenue mainly from the sale of petroleum products and merchandise. The Company sells gasoline in the United States 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-32, Certain Long-Lived Assets at December 31 exclude investments, noncurrent receivables, deferred tax assets and goodwill and other intangible assets.

Excise taxes on petroleum products of $1,741,707,000, $1,459,713,000 and $1,477,873,000 for the years 2006, 2005 and 2004, respectively, that were collected by the Company and remitted to various government entities were excluded from revenues and costs and expenses.

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Segment Information *(Millions of dollars)*	**U.S.**	**Canada**	**Exploration and Production** **U.K.**	**Ecuador**	**Malaysia**	**Other**	**Total**
Year ended December 31, 2006							
Segment income (loss)	**$ 212.4**	**329.7**	**60.7**	**38.4**	**(5.9)**	**(19.4)**	**615.9**
Revenues from external customers	**626.9**	**674.1**	**180.6**	**122.7**	**219.6**	**3.7**	**1,827.6**
Intersegment revenues		**118.3**					**118.3**
Interest income							
Interest expense, net of capitalization							
Income tax expense (benefit)	**110.8**	**101.6**	**73.7**	**24.9**	**35.7**	**.9**	**347.6**
Significant noncash charges (credits)							
Depreciation, depletion, amortization	**85.2**	**114.7**	**22.1**	**27.3**	**47.2**	**.5**	**297.0**
Accretion of asset retirement obligations	**3.0**	**4.6**	**1.8**		**.8**	**.6**	**10.8**
Provisions for major repairs		**6.1**					**6.1**
Amortization of undeveloped leases	**17.3**	**3.7**				**1.5**	**22.5**
Deferred and noncurrent income taxes	**(5.7)**	**(4.3)**	**13.0**		**15.0**	**(.6)**	**17.4**
Additions to property, plant, equipment	**112.0**	**181.5**	**27.8**	**34.8**	**505.9**	**24.1**	**886.1**
Total assets at year-end	**880.2**	**1,755.6**	**185.4**	**145.2**	**1,386.0**	**98.6**	**4,451.0**
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 (benefit)	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

Geographic Information *(Millions of dollars)*	**U.S.**	**Certain Long-Lived Assets at December 31** **Canada**	**U.K.**	**Ecuador**	**Malaysia**	**Other**	**Total**
2006	**$ 1,804.3**	**1,519.7**	**353.2**	**103.2**	**1,236.3**	**97.7**	**5,114.4**
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

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Segment Information (Continued)	**Refining and Marketing**			**Corp. &**	
(Millions of dollars)	**North America**	**U.K.**	**Total**	**Other**	**Consolidated**
Year ended December 31, 2006					
Segment income (loss)	**$ 73.4**	**31.7**	**105.1**	**(82.7)**	**638.3**
Revenues from external customers	**11,441.8**	**1,019.7**	**12,461.5**	**18.3**	**14,307.4**
Intersegment revenues					**118.3**
Interest income				**26.5**	**26.5**
Interest expense, net of capitalization				**9.5**	**9.5**
Income tax expense (benefit)	**37.3**	**14.7**	**52.0**	**(9.5)**	**390.1**
Significant noncash charges (credits)					
Depreciation, depletion, amortization	**70.7**	**13.0**	**83.7**	**3.4**	**384.1**
Accretion of asset retirement obligations	**.1**		**.1**		**10.9**
Provisions for major repairs	**17.1**	**4.4**	**21.5**	**.1**	**27.7**
Amortization of undeveloped leases					**22.5**
Deferred and noncurrent income taxes	**10.4**	**(2.9)**	**7.5**	**4.6**	**29.5**
Additions to property, plant, equipment	**163.6**	**9.8**	**173.4**	**6.3**	**1,065.8**
Total assets at year-end	**1,980.8**	**361.3**	**2,342.1**	**652.6**	**7,445.7**
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

Geographic Information		**Revenues from External Customers for the Year**					
(Millions of dollars)	**U.S.**	**U.K.**	**Canada**	**Ecuador**	**Malaysia**	**Other**	**Total**
2006	**$ 12,029.5**	**1,203.6**	**724.6**	**126.2**	**219.7**	**3.8**	**14,307.4**
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

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

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

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

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

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

Oil reserves in Ecuador are derived from a participation contract covering Block 16 in the Amazon region. This Block 16 contract expires in early 2012. Oil reserves associated with the participation contract in Ecuador totaled 11.1 million barrels at December 31, 2006. Oil and natural gas reserves in Malaysia are associated with production sharing contracts for Blocks SK 309/311 and K. Malaysia reserves include oil and gas to be received for both cost recovery and profit provisions under the contracts. Oil and natural gas reserves associated with the production sharing contracts in Malaysia totaled 54.3 million barrels and 337.5 billion cubic feet, respectively, at December 31, 2006.

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.

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, 2006.

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Schedule 1 Estimated Net Proved Oil Reserves

(Millions of barrels)	United States	Canada*	United Kingdom	Ecuador	Malaysia	Total
Proved						
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
Revisions of previous estimates	**(2.6)**	**2.4**		**(2.3)**	**2.3**	**(.2)**
Improved recovery		**.3**				**.3**
Purchases of properties		**.3**				**.3**
Extensions and discoveries	**5.4**	**5.1**			**8.6**	**19.1**
Production	**(7.7)**	**(10.2)**	**(2.6)**	**(3.1)**	**(4.1)**	**(27.7)**
December 31, 2006	**44.0**	**43.7**	**20.7**	**11.1**	**54.3**	**173.8**
Proved Developed						
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
December 31, 2006	**26.7**	**41.1**	**18.0**	**8.5**	**4.8**	**99.1**

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

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Schedule 2 Estimated Net Proved Natural Gas Reserves

(Billions of cubic feet)	United States	Canada*	United Kingdom	Malaysia	Total
Proved					
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
Revisions of previous estimates	**(14.2)**	**(1.6)**		**74.6**	**58.8**
Purchases of properties		**2.0**			**2.0**
Extensions and discoveries	**5.4**			**262.9**	**268.3**
Production	**(20.7)**	**(4.1)**	**(3.7)**		**(28.5)**
December 31, 2006	**148.6**	**20.9**	**24.4**	**337.5**	**531.4**
Proved Developed					
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
December 31, 2006	**70.6**	**20.6**	**22.3**		**113.5**

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

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

The Company has a 5% interest in Syncrude, the world s largest tar sands synthetic oil production project located in Alberta, Canada. In addition to conventional liquids and natural gas proved reserves, Murphy has significant proved synthetic oil reserves associated with Syncrude that are shown in the table below. For internal management purposes, Murphy views these reserves and ongoing production and development as an integral part of its total Exploration and Production operations. However, the U.S. Securities and Exchange Commission s regulations define Syncrude as a mining operation, and therefore, do not permit these synthetic oil proved reserves to be included as a part of conventional oil and natural gas reserves. These reserves are also not included in the Company s schedule of Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, which can be found on page F-40.

Synthetic Oil Proved Reserves

(Millions of barrels)

December 31, 2003	136.8
December 31, 2004	138.0
December 31, 2005	133.1
December 31, 2006	**125.9**

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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, 2006							
Property acquisition costs							
Unproved	**$ 13.0**	**.9**					**13.9**
Proved							
Total acquisition costs	**13.0**	**.9**					**13.9**
Exploration costs[3]	**119.2**	**4.9**		**1.5**	**185.6**	**26.8**	**338.0**
Development costs[3]	**72.5**	**138.3**	**30.4**	**34.8**	**460.3**	**4.6**	**740.9**
Total costs incurred	**204.7**	**144.1**	**30.4**	**36.3**	**645.9**	**31.4**	**1,092.8**
Charged to expense							
Dry hole expense	**56.4**	**.2**		**1.5**	**52.5**	**.4**	**111.0**
Geophysical and other costs	**30.6**	**1.2**	**.2**		**46.8**	**6.9**	**85.7**
Total charged to expense	**87.0**	**1.4**	**.2**	**1.5**	**99.3**	**7.3**	**196.7**
Property additions	**$ 117.7**	**142.7**	**30.2**	**34.8**	**546.6**	**24.1**	**896.1**
Year Ended December 31, 2005							
Property acquisition costs							
Unproved	$ 32.5	2.0					34.5
Proved		.2					.2
Total acquisition costs	32.5	2.2					34.7
Exploration costs[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

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[1] Excludes property additions for the Company s 5% interest in synthetic oil operations in Canada of $42.2 million in 2006, $112.9 million in 2005 and $110.6 million in 2004.

[2] Excludes property additions of $4.6 million in 2004 related to discontinued operations.

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

2006							
Exploration costs	$ 2.6				(2.6)		
Development costs	3.1	3.4	2.4		43.3		52.2
	$ 5.7	3.4	2.4		40.7		52.2
2005							
Exploration costs	$ 1.1				2.1		3.2
Development costs	8.1	5.8	.4				14.3
	$ 9.2	5.8	.4		2.1		17.5
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

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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, 2006									
Revenues									
Crude oil and natural gas liquids									
Sales to unaffiliated enterprises	**$ 440.1**	**407.4**	**156.8**	**122.7**	**219.6**		**1,346.6**	**220.3**	**1,566.9**
Transfers to consolidated operations		**68.6**					**68.6**	**49.7**	**118.3**
Natural gas									
Sales to unaffiliated enterprises	**160.4**	**24.1**	**23.3**				**207.8**		**207.8**
Total oil and gas revenues	**600.5**	**500.1**	**180.1**	**122.7**	**219.6**		**1,623.0**	**270.0**	**1,893.0**
Other operating revenues	**26.4**	**22.3**	**.5**			**3.7**	**52.9**		**52.9**
Total revenues	**626.9**	**522.4**	**180.6**	**122.7**	**219.6**	**3.7**	**1,675.9**	**270.0**	**1,945.9**
Costs and expenses									
Production expenses	**79.3**	**102.6**	**18.4**	**29.7**	**32.7**		**262.7**	**121.9**	**384.6**
Exploration costs charged to expense	**87.0**	**1.4**	**.2**	**1.5**	**99.3**	**7.3**	**196.7**		**196.7**
Undeveloped lease amortization	**17.3**	**3.7**				**1.5**	**22.5**		**22.5**
Depreciation, depletion and amortization	**85.2**	**97.1**	**22.1**	**27.3**	**47.2**	**.5**	**279.4**	**17.6**	**297.0**
Accretion of asset retirement obligations	**3.0**	**4.1**	**1.8**		**.8**	**.6**	**10.3**	**.5**	**10.8**
Net costs associated with hurricanes	**1.9**						**1.9**		**1.9**
Selling and general expenses	**30.0**	**11.4**	**3.7**	**.9**	**9.8**	**12.3**	**68.1**	**.8**	**68.9**
Total costs and expenses	**303.7**	**220.3**	**46.2**	**59.4**	**189.8**	**22.2**	**841.6**	**140.8**	**982.4**
	323.2	**302.1**	**134.4**	**63.3**	**29.8**	**(18.5)**	**834.3**	**129.2**	**963.5**
Income tax expense	**110.8**	**72.4**	**73.7**	**24.9**	**35.7**	**.9**	**318.4**	**29.2**	**347.6**
Results of operations*	**$ 212.4**	**229.7**	**60.7**	**38.4**	**(5.9)**	**(19.4)**	**515.9**	**100.0**	**615.9**
Year Ended December 31, 2005									
Revenues									
Crude oil and natural gas liquids									
Sales to unaffiliated enterprises	$ 448.8	471.3	159.8	116.6	232.9		1,429.4	213.4	1,642.8
Transfers to consolidated operations		48.4					48.4	11.3	59.7
Natural gas									
Sales to unaffiliated enterprises	216.6	29.7	19.9				266.2		266.2
Total oil and gas revenues	665.4	549.4	179.7	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
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

Net costs associated with hurricanes	12.4	3.4	1.2		.2		17.2	1.6	18.8
Selling and general expenses	22.0	8.2	2.8	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

* Excludes corporate overhead and interest in 2006 and 2005 and discontinued operations in 2005. Income from discontinued operations was $8.6 million in 2005.

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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, 2004									
Revenues									
Crude oil and natural gas liquids									
Sales to unaffiliated enterprises	$ 248.4	371.8	146.8	30.8	167.2		965.0	142.9	1,107.9
Transfers to consolidated operations		31.5					31.5	31.3	62.8
Natural gas									
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 2004. Income from discontinued operations was $204.9 million in 2004.

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

(Millions of dollars)	United States	Canada*	United Kingdom	Ecuador	Malaysia	Total
December 31, 2006						
Future cash inflows	**$ 3,178.8**	**1,880.7**	**1,337.0**	**331.1**	**3,407.4**	**10,135.0**
Future development costs	**(398.8)**	**(17.8)**	**(53.7)**	**(53.8)**	**(672.2)**	**(1,196.3)**
Future production and abandonment costs	**(567.3)**	**(600.4)**	**(372.0)**	**(131.7)**	**(479.9)**	**(2,151.3)**
Future income taxes	**(624.5)**	**(318.1)**	**(468.9)**	**(48.0)**	**(652.5)**	**(2,112.0)**
Future net cash flows	**1,588.2**	**944.4**	**442.4**	**97.6**	**1,602.8**	**4,675.4**
10% annual discount for estimated timing of cash flows	**(444.0)**	**(177.0)**	**(126.0)**	**(22.1)**	**(385.4)**	**(1,154.5)**
Standardized measure of discounted future net cash flows	**$ 1,144.2**	**767.4**	**316.4**	**75.5**	**1,217.4**	**3,520.9**
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

* Excludes discounted future net cash flows from synthetic oil of $1,096.0 million at December 31, 2006, $1,201.0 million at December 31, 2005 and $708.6 million at December 31, 2004.

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

(Millions of dollars)	2006	2005	2004
Net changes in prices, production costs and development costs	**$ (1,948.7)**	2,758.8	(1.4)
Sales and transfers of oil and gas produced, net of production costs	**(1,413.2)**	(1,732.9)	(1,143.0)
Net change due to extensions and discoveries	**1,026.0**	406.5	1,056.5
Net change due to purchases and sales of proved reserves	**8.8**	(274.0)	(272.0)
Development costs incurred	**645.2**	520.2	310.7
Accretion of discount	**613.6**	414.0	421.1
Revisions of previous quantity estimates	**20.7**	(96.9)	(443.4)

Net change in income taxes	**379.5**	(589.1)	34.0
Net increase (decrease)	**(668.1)**	1,406.6	(37.5)
Standardized measure at January 1	**4,189.0**	2,782.4	2,819.9
Standardized measure at December 31	**$ 3,520.9**	4,189.0	2,782.4

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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, 2006									
Unproved oil and gas properties	**$ 192.7**	**65.6**			**235.5**	**96.2**	**590.0**		**590.0**
Proved oil and gas properties	**932.1**	**1,471.5**	**437.0**	**340.9**	**1,126.1**	**3.3**	**4,310.9**	**758.9**	**5,069.8**
Gross capitalized costs	**1,124.8**	**1,537.1**	**437.0**	**340.9**	**1,361.6**	**99.5**	**4,900.9**	**758.9**	**5,659.8**
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	**(54.0)**	**(14.7)**				**(7.3)**	**(76.0)**		**(76.0)**
Proved oil and gas properties	**(366.3)**	**(645.9)**	**(266.1)**	**(237.7)**	**(132.8)**	**(3.3)**	**(1,652.1)**	**(122.5)**	**(1,774.6)**
Net capitalized costs	**$ 704.5**	**876.5**	**170.9**	**103.2**	**1,228.8**	**88.9**	**3,172.8**	**636.4**	**3,809.2**
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	796.5	1,259.6	406.7	306.1	605.6	2.9	3,377.4	720.1	4,097.5
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	(285.5)	(552.8)	(242.6)	(212.2)	(92.4)	(2.9)	(1,388.4)	(105.9)	(1,494.3)
Net capitalized costs	$ 690.0	803.4	164.1	93.9	726.7	66.8	2,544.9	614.2	3,159.1

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, 2006					
Sales and other operating revenues	**$ 2,987.1**	**3,798.0**	**4,147.7**	**3,346.5**	**14,279.3**
Income before income taxes	**211.4**	**291.8**	**382.3**	**142.9**	**1,028.4**
Net income	**113.9**	**214.0**	**222.8**	**87.6**	**638.3**
Net income per Common share basic	**0.61**	**1.15**	**1.20**	**0.47**	**3.43**
Net income per Common share diluted	**0.60**	**1.13**	**1.18**	**0.46**	**3.37**
Cash dividend per Common share	**.1125**	**.1125**	**.15**	**.15**	**.525**
Market price of Common Stock[1]					
High	**59.15**	**55.86**	**56.90**	**54.28**	**59.15**
Low	**45.36**	**47.23**	**45.90**	**45.12**	**45.12**
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					
Continuing operations	0.61	1.89	1.20	0.83	4.54
Discontinued operations			0.05		0.05
Net income	0.61	1.89	1.25	0.83	4.59
Income per Common share diluted					
Continuing operations	0.60	1.85	1.18	0.82	4.46
Discontinued operations			0.05		0.05
Net income	0.60	1.85	1.23	0.82	4.51
Cash dividend per Common share	.1125	.1125	.1125	.1125	.45
Market price of Common Stock[1]					
High	52.35	54.87	55.98	55.79	55.98
Low	38.05	43.10	48.94	42.08	38.05

[1] Prices are as quoted on the New York Stock Exchange.

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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
2006					
Deducted from asset accounts:					
Allowance for doubtful accounts	**$ 14.5**	**.3**	**(4.6)**	**.2**	**10.4**
Deferred tax asset valuation allowance	**151.1**	**54.7**			**205.8**
Included in liabilities:					
Accrued major repair costs	**55.3**	**27.7**	**(12.0)**	**.2**	**71.2**
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

1 Amounts primarily represent changes in foreign currency exchange rates.
2 Includes recognition of deferred income tax benefits of $31.9 million in 2004 for Block K in Malaysia.

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GLOSSARY OF TERMS

3-D seismic

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

bitumen or oil sands

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

deepwater

offshore location in greater than 1,000 feet of water

downstream

refining and marketing operations

dry hole

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

exploratory

wildcat and delineation, e.g., exploratory wells

feedstock

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

hydrocarbons

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

throughput

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

upstream

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

wildcat

well drilled to target an untested or unproved geologic formation