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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2002

OR

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

For the transition period from __________ to __________

Commission file number 1-8590

MURPHY OIL CORPORATION
(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

Aggregate market value of the voting stock held by non-affiliates of the registrant, based on average price at January 31, 2003, as quoted by the New York Stock Exchange, was approximately $2,924,876,000.

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☑ No ☐.

Aggregate market value of the voting stock held by non-affiliates of the registrant, based on average price at June 28, 2002, as quoted by the New York Stock Exchange, was approximately $2,894,828,000.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2003 was 91,699,376.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 14, 2003 have been incorporated by reference in Part III herein.

MURPHY OIL CORPORATION

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PART I

Items 1. and 2. BUSINESS AND PROPERTIES

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 presently subdivided into geographic segments for North America and United Kingdom. Canadian pipeline and trucking operations were sold in May 2001. Additionally, "Corporate and Other Activities" include interest income, interest expense and overhead not allocated to the segments.

The information appearing in the 2002 Annual Report to Security Holders (2002 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. A narrative of the graphic and image information that appears in the paper format version of Exhibit 13 is included in the electronic Form 10-K document as an appendix to Exhibit 13.

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 8 through 17, F-13, F-29 through F-31, F-35 through F-37, and F-39 of this Form 10-K report and on pages 4 through 12 of the 2002 Annual Report.

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

During 2002, Murphy's principal exploration and production activities were conducted in the United States, Ecuador and Malaysia by wholly owned Murphy Exploration & Production Company (Murphy Expro) 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 2002 was in the United States, Canada, the United Kingdom and Ecuador; its natural gas was produced and sold in the United States, Canada and the United Kingdom. MOCL owns a 5% interest in Syncrude Canada Ltd., which utilizes its assets to extract bitumen from oil sand deposits in northern Alberta and to upgrade this bitumen into synthetic crude oil.

Murphy's estimated net quantities of proved oil and gas reserves and proved developed oil and gas reserves at December 31, 1999, 2000, 2001 and 2002 by geographic area are reported on pages F-33 and F-34 of this Form 10-K report. Murphy has not filed and is not required to file any estimates of its total net proved oil or gas reserves on a recurring basis with any federal or foreign governmental regulatory authority or agency other than the U.S. Securities and Exchange Commission. Annually, Murphy reports gross reserves of properties operated in the United States to the U.S. Department of Energy; such reserves are derived from the same data from which estimated net proved reserves of such properties are determined.

Net crude oil, condensate, and gas liquids production and sales, and net natural gas sales by geographic area with weighted average sales prices for each of the five years ended December 31, 2002 are shown on page 13 of the 2002 Annual Report.

Production expenses for the last three years in U.S. dollars per equivalent barrel are discussed on page 14 of this Form 10-K report. For purposes of these computations, natural gas sales volumes are converted to equivalent barrels of crude oil using a ratio of six thousand cubic feet (MCF) of natural gas to one barrel of crude oil.

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

At December 31, 2002, 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 applicable to Murphy's working interest.

	Developed		Undeveloped		Total	
Area (Thousands of acres)	Gross	Net	Gross	Net	Gross	Net
United States – Onshore	18	7	32	20	50	27
– Gulf of Mexico	20	6	1,139	722	1,159	728
– Frontier	8	*	64	13	72	13
Total United States	46	13	1,235	755	1,281	768
Canada – Onshore	851	292	1,263	868	2,114	1,160
– Offshore	88	7	12,129	2,040	12,217	2,047
Total Canada	939	299	13,392	2,908	14,331	3,207
United Kingdom	78	11	717	201	795	212
Ecuador	7	1	524	105	531	106
Malaysia	—	—	11,498	9,192	11,498	9,192
Ireland	—	—	650	98	650	98
Spain	—	—	36	6	36	6
Totals	1,070	324	28,052	13,265	29,122	13,589
Oil sands in Canada	95	5	158	8	253	13

* less than one.

The only significant undeveloped acreage that expires in the next three years is approximately 2.4 million acres in shallow-water Blocks SK 309 and SK 311 in Malaysia that is not included in the West Patricia discovery area. The Company is currently negotiating to extend the exploration rights for this acreage.

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.

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The following table shows the number of oil and gas wells producing or capable of producing at December 31, 2002.

Country	Oil Wells		Gas Wells	
	Gross	Net	Gross	Net
United States	184	62	142	51
Canada	2,914	573	836	386
United Kingdom	103	12	22	2
Ecuador	72	14	—	—
Totals	3,273	661	1,000	439
Wells included above with multiple completions and counted as one well each	30	16	30	18

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

	United States		Canada		United Kingdom		Ecuador		Malaysia and Other		Total	
	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry
2002												
Exploratory	1.0	3.2	8.8	4.1	—	.5	—	—	4.3	3.7	14.1	11.5
Development	2.2	—	45.5	3.9	.7	.2	3.4	—	3.4	—	55.2	4.1
2001												
Exploratory	6.9	1.7	27.3	12.1	—	—	—	—	1.0	2.0	35.2	15.8
Development	4.1	—	24.7	1.7	.6	.1	2.4	—	—	—	31.8	1.8
2000												
Exploratory	2.0	3.9	6.4	12.0	.1	.3	—	—	.8	—	9.3	16.2
Development	.3	—	51.7	4.0	.6	.1	1.0	—	—	—	53.6	4.1

Murphy's drilling wells in progress at December 31, 2002 are shown below.

Country	Exploratory		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	1	*	2	.9	3	.9
Canada	5	1.9	4	1.0	9	2.9
United Kingdom	—	—	9	.7	9	.7
Malaysia	—	—	2	1.7	2	1.7
Totals	6	1.9	17	4.3	23	6.2

* less than 0.1.

Additional information about current exploration and production activities is reported on pages 4 through 9 of the 2002 Annual Report.

Refining and Marketing

Murphy Oil USA, Inc. (MOUSA), a wholly owned subsidiary, owns and operates two refineries in the United States. The Meraux, Louisiana refinery is located on fee land and on two leases that expire in 2010 and 2021, at which times the Company has options to purchase the leased acreage at fixed prices. The refinery at Superior, Wisconsin is located on fee land. Murco Petroleum Limited (Murco), a wholly owned U.K. subsidiary serviced by Murphy Eastern Oil Company, has an effective 30% interest in a refinery at Milford Haven, Wales that can process 108,000 barrels of crude oil a day. Refinery capacities at December 31, 2002 are shown in the following table.

	Meraux, Louisiana	Superior, Wisconsin	Milford Haven, Wales (Murco's 30%)	Total
Crude capacity – b/sd*	100,000	35,000	32,400	167,400
Process capacity – b/sd*				
Vacuum distillation	50,000	20,500	16,500	87,000
Catalytic cracking – fresh feed	38,000	11,000	9,960	58,960
Naphtha hydrotreating	22,000	9,000	5,490	36,490
Catalytic reforming	18,000	8,000	5,490	31,490
Distillate hydrotreating	15,000	7,800	20,250	43,050
Gas oil hydrotreating	27,500	—	—	27,500
Solvent deasphalting	18,000	—	—	18,000
Isomerization	—	2,000	3,400	5,400
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	4,300,000	3,054,000	2,638,000	9,992,000

* Barrels per stream day.

The Company is in the process of expanding the Meraux refinery, with the expansion scheduled to be completed and operational by the fourth quarter 2003. The expansion will allow the refinery to meet new low-sulfur product specifications which become effective in 2006. The expansion includes a new hydrocracker unit, central control room and two new utility boilers; expansion of the crude oil processing capacity from 100,000 barrels per stream day (b/sd) to 125,000 b/sd, expansion of naphtha hydrotreating capacity from 22,000 b/sd to 35,000 b/sd, and expansion of the catalytic reforming capacity from 18,000 b/sd to 32,000 b/sd; and construction of a new sulfur recovery complex, including amine regeneration, sour water stripping and high efficiency sulfur recovery.

MOUSA markets refined products through a network of retail gasoline stations and branded and unbranded wholesale customers in a 23-state area of the southern and midwestern United States. Murphy's retail stations are primarily located in the parking areas of Wal-Mart stores 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, 16 terminals that are jointly owned and operated by others, and numerous terminals owned by others. Of the terminals wholly owned or jointly owned, four are supplied by marine transportation, three are supplied by truck, two are adjacent to MOUSA's refineries and 18 are supplied by pipeline. 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, 2002, the Company marketed products through 506 Murphy USA stations and 402 branded wholesale SPUR stations. MOUSA plans to add about 100 new Murphy USA stations at Wal-Mart sites in the southern and midwestern United States in 2003. In February 2002, the Company and Wal-Mart reached an agreement for a Canadian subsidiary of the Company to market products through Murphy Canada™ stations at select Wal-Mart stores across Canada. The Company's subsidiary operates six stations at Wal-Mart sites in Canada at December 31, 2002. An additional seven Murphy Canada stations are expected to be added in 2003.

Murphy has master agreements that allow the Company to rent space in the parking lots of Wal-Mart stores 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 each master agreement is entered into, which contains the terms specific to that location. The terms of the agreements range from 10-15 years at each station, with Murphy holding two successive five-year extension options at each site. The agreements permit Wal-Mart to terminate the agreements in their entirety, or only as to affected sites, at its option for the following reasons: Murphy vacates or abandons the property; Murphy improperly transfers the rights under this agreement to another party; an agreement or a premises is taken upon execution or by process of law; Murphy files a petition in bankruptcy or becomes insolvent; Murphy fails to pay its debts as they become due; Murphy fails to pay rent or other sums required to be paid within 90 days after written notice; or Murphy fails to perform in any material way as required by the agreements. Sales from these stations amounted to 30.3% of total Company revenues in 2002, 22.5% in 2001 and 14.6% in 2000. As the Company continues to expand the number of gasoline stations at Wal-Mart sites, total revenue generated by this business is expected to grow proportionately.

At the end of 2002, 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 416 branded stations under the brand names MURCO and EP.

Murphy owns a 20% interest in a 120-mile refined products pipeline, with a capacity of 165,000 barrels a 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 LOOP LLC, which provides deepwater unloading accommodations off the Louisiana coast for oil tankers and onshore facilities for storage of crude oil. A crude oil pipeline with a diameter of 24 inches connects LOOP storage at Clovelly, Louisiana to the Meraux refinery. Murphy owns 29.4% of the first 22 miles of this pipeline from Clovelly to Alliance, Louisiana and 100% of the remaining 24 miles from Alliance to Meraux. The pipeline is connected to another company’s pipeline system, allowing crude oil transported by that system to also be shipped to the Meraux refinery. In February 2002, the Company sold its 22% interest in a 312-mile crude oil pipeline in Montana and Wyoming for $7 million.

In May 2001, the Company sold its Canadian pipeline and trucking operation, including seven crude oil pipelines with various ownership percentages and capacities. Murphy realized an after-tax gain of $71 million on this sale.

Additional information about current refining and marketing activities and a statistical summary of key operating and financial indicators for each of the five years ended December 31, 2002 are reported on pages 10, 11 and 14 of the 2002 Annual Report.

Employees

At December 31, 2002, Murphy had 4,010 employees – 1,980 full-time and 2,030 part-time.

Competition and Other Conditions Which May Affect Business

Murphy operates in the oil industry and experiences intense competition from other oil 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 independent 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 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 sites. The Company may be required to respond to operating and pricing policies of others, including producing country governments from whom it makes purchases. Additional information concerning current conditions of the Company’s business is reported under the caption “Outlook” beginning on page 22 of this Form 10-K report.

In 2002, the Company’s production of oil and natural gas represented approximately 0.1% of the respective worldwide totals. Murphy owned approximately 0.8% of the crude oil refining capacity in the United States and its market share of U.S. retail gasoline sales was approximately 0.8%.

The operations and earnings of Murphy have been and 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.

In addition, prices and availability of crude oil, natural gas and refined products could be influenced by political unrest and by various governmental policies to restrict or increase petroleum usage and supply. Other governmental actions that could affect Murphy's operations and earnings include tax changes and regulations concerning: currency fluctuations, protection and remediation of the environment (See the caption "Environmental" beginning on page 17 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 constant changes caused by governmental and political considerations and are often made in great haste in response to changing internal and worldwide economic conditions and to actions of other governments or specific events, it is not practical to attempt to predict the effects of such factors on Murphy's future operations and earnings.

Murphy's business is subject to operational hazards and risks normally associated with the exploration for and production of oil and natural gas and the refining and marketing of crude oil and petroleum products. The occurrence of an event, including but not limited to acts of nature, mechanical equipment failures, industrial accidents, fires and intentional attacks could result in the loss of hydrocarbons and associated revenues, environmental pollution or contamination, and personal injury or bodily injury, including death, for which the Company could be deemed to be liable, and could subject the Company to substantial fines and/or claims for punitive damages. 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, 2002, the Company maintained total excess liability insurance with limits of $500 million per occurrence covering employees, 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 gradual and/or sudden and accidental pollution events. There can be no assurance that such insurance will be adequate to offset lost revenues or 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.

Executive Officers of the Registrant

The age at January 1, 2003, 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 48; President and Chief Executive Officer since October 1994 and Director and Member of the Executive Committee since 1993. He served as Executive Vice President and Chief Operating Officer from 1992 to 1993 and President of MOUSA from 1989 to 1992.

W. Michael Hulse – Age 49; Executive Vice President – Worldwide Downstream Operations effective April 2003. Mr. Hulse was President of MOUSA from November 2001 to present. He served as President of Murphy Eastern Oil Company from April 1996 to November 2001.

Steven A. Cossé – Age 55; Senior Vice President since October 1994 and General Counsel since August 1991. Mr. Cossé was elected Vice President in 1993. For the eight years prior to August 1991, he was General Counsel for Ocean Drilling & Exploration Company (ODECO), a majority-owned subsidiary of Murphy.

Bill H. Stobaugh – Age 51; Vice President since May 1995, when he joined the Company. Prior to that, he had held various engineering, planning and managerial positions, the most recent being with an engineering consulting firm.

Kevin G. Fitzgerald – Age 47; Treasurer since July 2001. Mr. Fitzgerald was Director of Investor Relations from 1996 to June 2001, and also served in various capacities with the Company and ODECO between 1982 and 1996.

John W. Eckart – Age 44; Controller since March 2000. Mr. Eckart had been Assistant Controller since February 1995. He joined the Company as Auditing Manager in 1990.

Walter K. Compton – Age 40; Secretary since December 1996. He has been an attorney with the Company since 1988 and became Manager, Law Department, in November 1996.

Item 3. LEGAL PROCEEDINGS

In December 2000, two of the Company's Canadian subsidiaries, Murphy Oil Company Ltd. (MOCL) and Murphy Canada Exploration Company (MCEC) as plaintiffs filed an action in the Court of Queen's Bench of Alberta seeking a constructive trust over oil and gas leasehold rights to Crown lands in British Columbia. The suit alleges that the defendants, The Predator Corporation Ltd. and Predator Energies Partnership (collectively Predator) and Ricks Nova Scotia Co. (Ricks), acquired the lands after first inappropriately obtaining confidential and proprietary data belonging to the Company and its partner. In January 2001, Ricks, representing an undivided 75% interest in the lands in question, settled its portion of the litigation by conveying its interest to the Company and its partner at cost. In 2001, Predator, representing the remaining undivided 25% of the lands in question, filed a counterclaim, as subsequently amended, against MOCL and MCEC and MOCL's President individually seeking compensatory damages of C$4.61 billion. The Company believes that the counterclaim is without merit and that the amount of damages sought is frivolous. While the litigation is in its preliminary stages and no assurance can be given about the outcome, the Company does not believe that the ultimate resolution of this suit will have a material adverse effect on its financial condition.

Murphy and its subsidiaries are engaged in a number of other legal proceedings, all of which Murphy considers routine and incidental to its business and none of which is expected to have a material adverse effect on the Company's financial condition. The ultimate resolution of matters referred to in this item could have a material adverse effect on the Company's earnings 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 2002.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The Company's Common Stock is traded on the New York Stock Exchange and the Toronto Stock Exchange using "MUR" as the trading symbol. There were 2,826 stockholders of record as of December 31, 2002. Information as to high and low market prices per share and dividends per share by quarter for 2002 and 2001 are reported on page F-40 of this Form10-K report.

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Item 6. SELECTED FINANCIAL DATA

(Thousands of dollars except per share data)	2002	2001	2000	1999	1998
Results of Operations for the Year[1]					
Sales and other operating revenues[2]	$3,966,516	3,743,986	3,630,195	2,076,103	1,718,110
Net cash provided by continuing operations	526,969	630,631	738,083	332,455	290,526
Income (loss) from continuing operations	97,510	328,430	298,526	113,980	(17,317)
Net income (loss)	111,508	330,903	296,828	119,707	(14,394)
Per Common share – diluted[3]					
Income (loss) from continuing operations	1.06	3.60	3.30	1.27	(.19)
Net income (loss)	1.21	3.63	3.28	1.33	(.16)
Cash dividends per Common share[3]	.775	.75	.725	.70	.70
Percentage return on					
Average stockholders' equity	7.3	23.5	26.4	12.3	(1.3)
Average borrowed and invested capital	5.8	17.7	20.3	9.7	(.6)
Average total assets	3.9	10.2	11.2	5.2	(.6)
Capital Expenditures for the Year					
Continuing operations					
Exploration and production	$ 631,799	680,100	392,732	295,906	330,842
Refining and marketing	234,714	175,186	153,750	88,075	55,025
Corporate and other	1,136	5,806	11,415	2,572	2,127
	867,649	861,092	557,897	386,553	387,994
Discontinued operations	451	3,348	—	52	805
	$ 868,100	864,440	557,897	386,605	388,799
Financial Condition at December 31					
Current ratio	1.19	1.07	1.10	1.22	1.15
Working capital	$ 136,268	38,604	71,710	105,477	56,616
Net property, plant and equipment	2,886,599	2,525,807	2,184,719	1,782,741	1,662,362
Total assets	3,885,775	3,259,099	3,134,353	2,445,508	2,164,419
Long-term debt	862,808	520,785	524,759	393,164	333,473
Stockholders' equity	1,593,553	1,498,163	1,259,560	1,057,172	978,233
Per share[3]	17.38	16.53	13.98	11.75	10.88
Long-term debt – percent of capital employed	35.1	25.8	29.4	27.1	25.4

1 Includes effects on income of nonrecurring items in 2002, 2001 and 2000 that are detailed in Management's Discussion and Analysis of Financial Condition and Results of Operations. Also, nonrecurring items in 1999 and 1998 increased (decreased) net income (loss) by $19,753, $.22 per diluted share, and $(57,935), $(.64) per diluted share, respectively.

2 Amounts for 1998 to 2001 have been restated to reflect the adoption of EITF Issue 02-3. See page 19 of this Form 10-K for further information.

3 Per Common share amounts for 1998 to 2001 have been adjusted to reflect a two-for-one stock split effective December 30, 2002.

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

Results of Operations

The Company reported net income in 2002 of $111.5 million, $1.21 per diluted share, compared to net income in 2001 of $330.9 million, $3.63 per share. In 2000 the Company earned $296.8 million, $3.28 per diluted share. All 2001 and 2000 earnings per share have been adjusted to reflect the two-for-one stock split effective December 30, 2002. In December 2002 the Company sold its interest in Ship Shoal Block 113 in the Gulf of Mexico for an after-tax gain of $10.6 million. In accordance with Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which the Company adopted on January 1, 2002, the results of operations for Ship Shoal Block 113 have been reflected as discontinued operations in all years presented. Therefore, the aforementioned gain on disposal of $10.6 million in 2002, and routine operating results of the field, have been included net of income tax expense as Discontinued Operations in the consolidated statements of income for the three years ended December 31, 2002. Income from continuing operations was $97.5 million in 2002, $1.06 per share; $328.4 million in 2001, $3.60 per share; and $298.5 million in 2000, $3.30 per share.

The three year period ended December 31, 2002 included certain nonrecurring items which can obscure underlying trends of operating results and affect comparability between years. Although results excluding nonrecurring items is considered a non-GAAP measure, the Company's management believes this information is useful in assessing Murphy Oil's performance. Nonrecurring items reduced income from continuing operations in 2002 by $6.7 million, but increased this amount by $67.6 million in 2001 and $1.5 million in 2000. Excluding these nonrecurring items, income from continuing operations amounted to $104.2 million in 2002, $260.8 million in 2001, and $297 million in 2000. In 2000 the Company recorded a net charge of $8.7 million, $.10 per share, as the cumulative effect of an accounting change for a one-time non-cash adjustment to record crude oil revenues at the time the oil is sold rather than as it is produced.

2002 vs. 2001 – Income from continuing operations in 2002 was $97.5 million, $1.06 per share, compared to $328.4 million, $3.60 per share, in 2001. The decline in 2002 results of $230.9 million was mainly due to a $193.6 million reduction in refining and marketing results, caused by both weaker refining margins in 2002 compared to 2001 in the U.S. and U.K. and a $74.3 million reduction in income from nonrecurring items in 2002. The lower income from nonrecurring items was primarily caused by a $71 million gain in 2001 from sale of Canadian pipeline and trucking operations. Earnings from the Company's exploration and production activities were $26.5 million lower in 2002 than in 2001 as record levels of oil and natural gas production and higher average oil prices were more than offset by lower natural gas sales prices, higher charges for property impairments and higher production and depreciation expenses.

Sales and other operating revenues were $222.5 million higher in 2002 than in 2001 due to record production and sales of crude oil and natural gas and higher sales volumes for refined products in North America and the United Kingdom. Gain on sale of assets declined by $96.4 million primarily due to the sale of Canadian pipeline and trucking assets in 2001. Interest and other income was $7.8 million lower in 2002 due to less interest earned on invested cash. Crude oil, natural gas and product purchases increased by $305.5 million in 2002 due to more purchases of finished products for retail marketing operations and a higher average purchase price for these products than in 2001. Operating expenses rose by $60.7 million mainly due to record oil and natural gas production, higher maintenance costs for oil and gas producing fields and $5 million of costs to repair uninsured damage from tropical storms in the Gulf of Mexico. Depreciation, depletion and amortization expense increased $73.4 million in 2002 due to higher oil and natural gas production and more retail marketing stations. Interest expense was $12.2 million more in 2002 due to higher average long-term borrowings than in 2001, including the sale of 10-year notes with a stated rate of 6.375% in 2002. Capitalized interest increased by $4.3 million due to ongoing projects to develop deepwater Gulf of Mexico fields, expand Syncrude, and build a hydrocracker and expand crude oil throughput capacity at the Meraux, Louisiana refinery. Income tax expense fell by $119.5 million essentially in line with lower pretax income from continuing operations.

2001 vs. 2000 – Income from continuing operations in 2001 was a company record $328.4 million, $3.60 per share, an increase of $29.9 million from the $298.5 million, $3.30 per share, earned in 2000. Record earnings in 2001 from the Company's refining and marketing operations and greater benefits from nonrecurring items were only partially offset by lower income from exploration and production activities. Improved refining and marketing results of $99.2 million were attributable to stronger unit margins in the U.S. refining business during the first half of 2001 and a $71 million nonrecurring profit on sale of Canadian pipeline and trucking operations in May 2001. Exploration and production results declined by $58.2 million in 2001 mainly caused by an 18% reduction in realized oil prices and higher exploration expenses. These were partially offset by higher oil and natural gas production and lower charges for property impairments.

Sales and other operating revenues in 2001 increased by $113.8 million compared to 2000 due to higher oil, natural gas and refined product sales volumes. Gain on sale of assets was up by $101.5 million due to the sale in May 2001 of the Canadian pipeline and trucking operations. Interest and other income was $7.5 million lower in 2001 due to less interest earned on invested cash balances and lower interest associated with settlement of prior year tax issues. Crude oil, natural gas and product purchases were $46 million higher due to more purchases of crude oil and refined products, with this effort partially mitigated by a lower average price than in 2000. Operating expenses increased by $66.5 million due to higher oil and natural gas production and more retail gasoline stations. The increase of $31.3 million in exploration expenses is explained on page 14. Selling and general expenses increased by $12.4 million primarily due to higher salaries and benefits and legal and professional fees in 2001. Depreciation, depletion and amortization expense rose by $15.7 million due to a combination of higher oil and gas production and more retail marketing stations. Amortization of goodwill of $3.1 million related to the acquisition of Beau Canada Exploration Ltd. (Beau Canada) in

November 2001. Impairment of properties was down by $17.4 million in 2001 due to less impairment write-downs for Gulf of Mexico and western Canada properties. Interest expense was $9.4 million higher in 2001 due to higher average borrowings during the year, primarily arising from the acquisition of Beau Canada in late 2000. Capitalized interest was $6.7 million more than in 2000 primarily due to continued development expenditures for the Terra Nova field, offshore Newfoundland. Income tax expense increased by $17.7 million in 2001 due to higher pretax earnings from continuing operations.

In the following table, the Company's results of operations for the three years ended December 31, 2002 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)	2002	2001	2000
Exploration and production			
United States	$ (11.8)	55.3	43.3
Canada	157.0	85.5	108.1
United Kingdom	49.6	78.6	90.2
Ecuador	12.0	11.5	21.1
Malaysia	(43.0)	(36.1)	(10.7)
Other	(2.8)	(7.3)	(6.3)
	161.0	187.5	245.7
Refining and marketing			
North America	(39.2)	139.6	31.5
United Kingdom	(.7)	14.1	23.0
	(39.9)	153.7	54.5
Corporate and other	(23.6)	(12.8)	(1.7)
Income from continuing operations	97.5	328.4	298.5
Discontinued operations	14.0	2.5	7.0
Income before cumulative effect of accounting change	111.5	330.9	305.5
Cumulative effect of accounting change	—	—	(8.7)
Net income	$ 111.5	330.9	296.8

Nonrecurring Items – Income from continuing operations in the table above includes the following nonrecurring items, which can affect underlying trends of operating results and comparability between years. These nonrecurring items are presented net of tax below and are discussed in more detail following the tables.

(Millions of dollars)	2002	2001	2000
Gain on sale of assets	$ 2.3	71.0	1.5
Tax settlements and tax rate change	14.7	8.9	25.6
Impairment of properties	(20.5)	(6.8)	(17.8)
Cost to repair storm damages	(3.2)	—	—
Provision for U.S. environmental matters	—	(5.5)	—
Loss on transportation and other disputed contractual items in Ecuador	—	—	(7.8)
Income (loss) from nonrecurring items	$ (6.7)	67.6	1.5

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These nonrecurring items were reflected in the following segments.

(Millions of dollars)	2002	2001	2000
Exploration and production			
United States	$ (6.7)	(5.8)	(13.6)
Canada	—	5.8	(4.2)
United Kingdom	—	1.9	—
Ecuador	—	—	(7.8)
	(6.7)	1.9	(25.6)
Refining and marketing			
North America	—	64.7	—
	—	64.7	—
Corporate and other	—	1.0	27.1
Income (loss) from nonrecurring items	$ (6.7)	67.6	1.5

- *Gain on sale of assets* – An after-tax gain of $2.3 million was recorded in the third quarter 2002 associated with the sale of assets. After-tax gains of $67.6 million and $3.4 million were recorded in the second and fourth quarter, respectively, of 2001 for the sale of Canadian pipeline and trucking assets. After-tax gains of $1.5 million were recorded in the second quarter of 2000 from the sale of U.S. corporate assets.
- *Tax settlements and tax rate change* – Income of $14.7 million was recorded in the third quarter 2002 from settlement of prior year tax matters. Income of $5.5 million was recorded in the third quarter of 2001 from a reduction in a Canadian provincial tax rate. In addition, settlement of income tax matters in the U.S. and U.K. provided income of $3.4 million in the fourth quarter of 2001. Income of $15.5 million and $10.1 million from settlement of U.S. income tax matters was recorded in the third quarter of 2000 and the fourth quarter of 2000, respectively.
- *Impairment of properties* – An after-tax charge of $14.6 million was recorded in the fourth quarter of 2002 to write-off the remaining cost in Destin Dome Blocks 56 and 57, offshore Florida. An agreement with the U.S. government restricts the Company's ability to seek approval for development of this significant natural gas discovery until at least 2012. Additionally, after-tax charges of $5.9 million, $6.8 million, $13.6 million and $4.2 million were recorded in the third quarter of 2002, the fourth quarter of 2001, the third quarter of 2000 and the fourth quarter of 2000, respectively, for the write-down of assets determined to be impaired. (See Note E to the consolidated financial statements.)
- *Cost to repair storm damages* – An after-tax charge of $3.2 million was recorded in the third quarter of 2002 for costs to repair uninsured equipment damages caused by tropical storms in the Gulf of Mexico.
- *Provision for U.S. environmental matters* – A $5.5 million charge was recorded in the third quarter of 2001 to resolve Clean Air Act violations at the Company's Superior, Wisconsin refinery.
- *Loss on transportation and other disputed contractual items in Ecuador* – A loss of $7.8 million was recorded in the fourth quarter of 2000, which included a $4.3 million expense related to prior years' transportation costs, a charge of $3.2 million to establish an allowance against doubtful accounts receivable associated with disputed contractual matters, and a charge of $.3 million to settle a disputed custom fee.

The effects of nonrecurring items on quarterly results of 2002 and 2001 are presented on page F-41 of this Form 10-K report.

Exploration and Production – Earnings from exploration and production operations were $161 million in 2002, $187.5 million in 2001 and $245.7 million in 2000. The decline in 2002 was caused by a 24% lower average natural gas sales price in North America, higher costs associated with property impairments and higher production and depreciation expenses. The unfavorable effects of these items were partially offset by record production of both crude oil and natural gas and a 10% higher average sales price for crude oil and condensate. Oil production from continuing operations increased by 13% in 2002 to 75,213 barrels per day and natural gas production from continuing operations rose by 5% to 292.9 million cubic feet per day. Higher property impairment expense in 2002 was mostly related to the write-off of remaining costs for Destin Dome Blocks 56 and 57, offshore Florida. Based on an agreement with the U.S. government, the Company may not seek approval for development of this significant natural gas discovery in Destin Dome until at least 2012. The decline in 2001 was primarily attributable to an 18% decline in the Company's average oil sales price compared to 2000. Additionally, exploration expenses increased over 2000, a significant portion of which were in foreign jurisdictions where the Company has no realized income tax benefits. Production of crude oil, condensate and natural gas liquids from continuing operations increased from 63,917 barrels per day in 2000 to 66,344 in 2001, a 4% increase. Natural gas sales volumes from continuing operations totaled 278.3 million cubic feet per day in 2001, up 23% from 226 million in 2000.

The results of operations for oil and gas producing activities for each of the last three years are shown by major operating areas on pages F-36 and F-37 of this Form 10-K report. Daily production and sales rates and weighted average sales prices are shown on page 13 of the 2002 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)	2002	2001	2000
United States			
Crude oil	$ 30.0	38.5	53.2
Natural gas	111.3	192.8	211.4
Canada			
Crude oil	304.8	167.2	193.9
Natural gas	197.6	182.6	99.0
Synthetic oil	106.3	95.8	91.5
United Kingdom			
Crude oil	163.0	181.5	214.6
Natural gas	7.0	12.1	7.8
Ecuador – crude oil	30.7	33.4	52.2
Total oil and gas revenues	$ 950.7	903.9	923.6

The Company's crude oil, condensate and natural gas liquids production from continuing operations averaged 75,213 barrels per day in 2002, 66,344 in 2001 and 63,917 in 2000. Oil production in the United States declined 13% to 4,128 barrels per day in 2002, following an 11% decline in 2001. The reduction in both years was primarily due to declines from existing fields in the Gulf of Mexico. Oil production in Canada increased 34% in 2002 to a record volume of 48,239 barrels per day. The Terra Nova field, offshore Newfoundland, commenced production in January 2002 and averaged 12,463 barrels per day for the year. The Company's share of net production at its synthetic oil operation improved 883 barrels per day, or 8%, in 2002 due to a combination of higher gross production and a lower net profit royalty caused by higher capital spending related to an ongoing expansion project. Before royalties, the Company's synthetic oil production was 11,477 barrels per day in 2002, 11,157 in 2001 and 10,145 in 2000. Production of light oil decreased 982 barrels per day, or 23%, and heavy oil production decreased 19% to 9,484 barrels per day in 2002 with both decreases primarily due to declines at existing western Canada fields. Production at Hibernia rose 21% in 2002 to 11,574 barrels per day due to better operating efficiency. U.K. production was down by 1,912 barrels per day, or 9%, primarily due to declines from the Company's "T" Block and Ninian fields in the North Sea. The Company produced 4,544 barrels of oil per day in Ecuador, 15% lower than in 2001, primarily due to further pipeline constraints on the existing oil pipeline. An additional pipeline is scheduled to commence operation in the second half of 2003.

During 2001, oil production in the United States declined 14% compared to 2000 and averaged 4,752 barrels per day. The reduction was due to declines from existing fields in the Gulf of Mexico. Oil production in Canada increased 15% in 2001 to 36,059 barrels per day. The Company's share of net production at its synthetic oil operation improved 2,036 barrels per day, or 24%, in 2001 due to both higher gross production and a lower net profit royalty caused by increased capital spending and a lower oil price. Production of light oil increased 1,258 barrels per day, or 41%, and heavy oil production increased 11% to 11,707 barrels per day in 2001 with both increases primarily due to the Company's acquisition of Beau Canada in November 2000. Production at Hibernia rose 4% in 2001 to 9,535 barrels per day due to better operating efficiency, primarily associated with improved handling of gas production. U.K. production was down by 681 barrels per day, or 3%, due to declines from the Company's existing fields in the North Sea. Oil production in Ecuador was 17% lower than 2000 and totaled 5,319 barrels per day. This reduction was caused by more pipeline constraints, which forced the operation to limit daily production.

Worldwide sales of natural gas from continuing operations were a record 292.9 million cubic feet per day in 2002, up from 278.3 million in 2001. Natural gas sales were 226 million cubic feet per day in 2000. Sales of natural gas in the United States were 88.1 million cubic feet per day in 2002, 112.6 million in 2001 and 141.4 million in 2000. The reductions in 2002 and 2001 were due to lower deliverability from maturing fields in the Gulf of Mexico. Natural gas sales in Canada in 2002 were at record levels for the seventh consecutive year as sales increased 30% to 197.9 million cubic feet per day. Canadian natural gas sales had increased more than 100% in 2001. The increase in 2002 was primarily due to higher production from the Ladyfern field, while the 2001 increase was due to the acquisition of Beau Canada in late 2000 and from new discoveries, including Ladyfern, in western Canada. Natural gas sales in the United Kingdom were 7 million cubic feet per day in 2002, down 47% compared to 2001. U.K. natural gas sales in 2001 increased 21% compared to 2000 levels and totaled 13.1 million cubic feet per day. The lower production in 2002 was due to declines at the Amethyst field in the North Sea, while the added volumes in 2001 were attributable to higher production at both the Amethyst and Mungo/Monan fields.

The average sales price for light crude oil in 2002 was comparable to 2001; however, heavy oil prices were significantly stronger in comparison to light oil prices during the year. In the United States, the Company's average monthly sales price for crude oil and condensate declined 3% compared to 2001 and averaged $24.25 per barrel for the year. In Canada, the sales price for light oil rose 1% to $22.60 per barrel. Heavy oil prices in Canada averaged $16.82 per barrel, up 52% from 2001. The sales price for crude oil from the Hibernia field rose 7% to $25.34 per barrel. The average sales price for oil from the new Terra Nova field was $25.38 per barrel. Synthetic oil prices in 2002 were $25.64 per barrel, up 2% from a year ago. Sales prices in the U.K. were about flat with 2001 at $24.39 per barrel and sales prices in Ecuador were up 16% to $19.64 per barrel.

Worldwide crude oil sales prices declined during 2001 compared to 2000. In the United States, the Company's average sales price for crude oil and condensate was $24.92 per barrel for the year, down 18% compared to 2000. In Canada, sales prices for light oil fell 19% to $22.40 per barrel. Canadian heavy oil prices were down 38% from 2000 and averaged $11.06 per barrel. The sales price for Hibernia crude oil decreased 12% to $23.77 per barrel. Synthetic oil prices in 2001 averaged $25.04 per barrel, down 15% from a year ago. Sales prices in the U.K. were $24.44 per barrel, a decline of 12%, and sales prices in Ecuador were down 23% to $17.00 per barrel.

The Company's North American natural gas sales prices were weaker during 2002 compared to 2001 due generally to a warmer than normal winter. Natural gas sales prices in North America decreased 24% from 2001 and averaged $2.94 per MCF in 2002 compared to $3.87 in the prior year. U.S. natural gas sales prices decreased 27% in 2002 and averaged $3.37 per MCF compared to $4.64 in the prior year. Canadian natural gas production was sold in 2002 at an average price of $2.74 per MCF, 16% lower than in 2001. The sales price for natural gas sold in the United Kingdom increased 10% to $2.76 per MCF.

North American natural gas sales price averaged $3.87 per MCF for the year 2001 compared to $3.90 in 2000. U.S. sales prices averaged $4.64 per MCF compared to $4.01 a year ago. However, the sales price for natural gas sold in Canada declined 11% to $3.28 per MCF. Prices in the United Kingdom increased to $2.52 per MCF from $1.81 in 2000.

Based on 2002 volumes and deducting taxes at marginal rates, each $1 per barrel and $.10 per MCF fluctuation in prices would have affected annual exploration and production earnings by $17.2 million and $5.8 million, respectively. The effect of these price fluctuations on consolidated net income cannot be measured because operating results of the Company's refining and marketing segments could be affected differently.

Production expenses were $229.6 million in 2002, $211 million in 2001 and $176.1 million in 2000. These amounts are shown by major operating area on pages F-36 and F-37 of this Form 10-K report. Costs per equivalent barrel during the last three years excluding discontinued operations were as follows.

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(Dollars per equivalent barrel)	2002	2001	2000
United States	$ 5.64	4.82	3.43
Canada			
Excluding synthetic oil	3.48	3.84	4.24
Synthetic oil	11.75	13.58	13.06
United Kingdom	5.03	3.75	3.46
Ecuador	8.17	7.60	6.65
Worldwide – excluding synthetic oil	4.29	4.24	3.96

The increase in the cost per equivalent barrel in the United States in both 2002 and 2001 was attributable to a combination of lower production and higher well servicing costs. Lower average costs in 2002 for Canada, excluding synthetic oil, was due to higher natural gas production volumes and new production from the Terra Nova field, offshore Newfoundland. The decrease in Canada during 2001, excluding synthetic oil, was primarily due to higher production of light oil, heavy oil and natural gas. The lower average cost per barrel for Canadian synthetic oil in 2002 was due to a combination of lower maintenance costs and higher net production, while the increased cost in 2001 was due to higher maintenance costs. The increase in average costs in the U.K. in 2002 was due to both higher costs to maintain mature properties, primarily at the Ninian field, and lower overall production. The increase in the United Kingdom during 2001 was also the result of higher costs for mature properties. Higher costs per unit in Ecuador in 2002 and 2001 were both due to lower oil production compared to the previous year.

Exploration expenses for each of the last three years are shown in total in the following table, and amounts are reported by major operating area on pages F-36 and F-37 on this Form 10-K report. Certain of the expenses are included in the capital expenditures total for exploration and production activities.

(Millions of dollars)	2002	2001	2000
Exploration and production			
Dry hole costs	$ 101.2	82.8	66.0
Geological and geophysical cost	23.4	36.0	36.3
Other costs	10.2	15.0	9.2
	134.8	133.8	111.5
Undeveloped lease amortization	24.6	23.1	14.1
Total exploration expenses	$ 159.4	156.9	125.6

The increase in dry hole costs in 2002 was caused by higher costs for unsuccessful exploration drilling wells in the deep waters of the Gulf of Mexico and Malaysia, which were offset in part by lower costs in 2002 for wells off the east coast of Canada. Dry hole costs were higher in 2001 than in 2000 as more unsuccessful drilling costs off the east coast of Canada were partially offset by lower costs in the deepwater Gulf of Mexico. Geological and geophysical costs were down in 2002 due to less spending for 3-D seismic on deepwater concessions in Malaysia. Other exploration expenses were lower in 2002 primarily due to more recoveries from the Company’s partner in Malaysia. Undeveloped leasehold amortization increased in 2001 compared to 2000 primarily because of lease acquisitions in western Canada.

Depreciation, depletion and amortization expense related to exploration and production operations totaled $247.2 million in 2002, $181.1 million in 2001 and $166.6 million in 2000. Higher costs in 2002 were caused by record oil and natural gas production, including start up of the Terra Nova field in January 2002, and more production from the Ladyfern field in Western Canada. The increase in 2001 was also due to higher oil and natural gas production volumes during the year.

The effective income tax rate for exploration and production operations was lower by approximately 1.5% of pretax earnings in 2002 compared to 2001 primarily due to higher benefits in the latter year from settlement of prior-year tax matters.

Approximately 94% of the Company’s U.S. proved oil reserves and 48% of the U.S. proved natural gas reserves are undeveloped. At December 31, 2002, about 95% of the total U.S. undeveloped reserves relate to deepwater Gulf of Mexico fields, including Medusa, Front Runner and Habanero, which are currently being developed by the Company. Medusa is expected to come on stream at mid-year 2003. Habanero should start up in the third quarter 2003 and

Front Runner is currently projected to produce first oil in 2004. On a worldwide basis, the Company has spent approximately $239 million in 2002, $208 million in 2001 and $111 million in 2000 to develop its undeveloped proved reserves. The Company expects to spend about $314 million in 2003, $142 million in 2004 and $62 million in 2005 to move undeveloped proved reserves to the developed category.

The U.S. Securities and Exchange Commission (SEC) is currently in the process of obtaining information from Murphy and other oil and gas companies operating in the Gulf of Mexico to assess how the industry is determining proved reserves related to new field discoveries. SEC regulations allow oil companies to recognize proved reserves if economic producibility is supported by either an actual production test or conclusive formation test. In the absence of a production test, compelling technical data must exist to recognize proved reserves related to the initial discovery of the oil or natural gas field. Production tests in deepwater environments are extremely expensive and the oil industry has increasingly depended on advanced technical testing to support economic producibility. Murphy has recorded proved reserves related to the initial discovery of four offshore fields based on conclusive formation tests rather than actual production tests. At the end of 2002, proved reserves for these four fields totaled 92 million barrels of oil equivalent, or approximately 20% of the Company's worldwide proved reserves, including synthetic oil. Three of the fields are currently being developed, including the Medusa, Front Runner and Habanero fields, with expected first production for these fields ranging from mid-2003 to the first half of 2004. Murphy believes the proved reserves are properly classified. Murphy has furnished the information requested by the SEC and is unable to predict the outcome of the SEC's staff review of the industry's practices. This issue is not expected to have a material effect on the Company's financial results. If the issue is not favorably resolved, the Company may be required to revise the manner in which it reports its proved reserves, which could affect its finding costs per barrel and reserve replacement ratios.

Refining and Marketing – The Company's refining and marketing operations lost $39.9 million in 2002. Earnings from this business were a record $153.7 million in 2001, including nonrecurring gains, while earnings in 2000 totaled $54.5 million. The unfavorable result in 2002 was due to two reasons – extremely weak refining margins throughout most of the year in both the United States and United Kingdom and a $71 million gain in 2001 on sale of the Company's former Canadian pipeline and trucking operations. Crude oil feedstock prices at the Company's U.S. and U.K. refineries were 6% and 4% higher, respectively, in 2002 than in 2001 and the increase in wholesale and retail sales prices for refined products in 2002 did not match the increased costs of crude oil in the markets served by the Company. North American operations, which now includes refining activities in the U.S. and marketing activities in the U.S. and Canada and formerly included pipeline and trucking operations in Canada prior to the sale of this business in 2001, lost $39.2 million in 2002 compared to profits of $139.6 million in 2001 and $31.5 million in 2000. The year 2001 included the aforementioned $71 million gain on sale of pipeline and trucking operations in Canada. Excluding this gain, the 2001 results were much improved over 2000 due to stronger refining and marketing margins and a higher percentage of sales through the Company's retail stations at Wal-Mart sites. Prior to the sale of the Canadian operations in 2001, this business generated a profit of $3.8 million in 2001 and $7.6 million in 2000. Operations in the U.K. lost $.7 million in 2002, but earned $14.1 million and $23 million in 2001 and 2000, respectively. The declines in 2002 and 2001 earnings compared to the prior year in the U.K. were caused by generally weaker refining margins than in the year before.

Unit margins (sales realizations less costs of crude oil, other feedstocks, refining operating expenses and depreciation and transportation to point of sale) averaged $.95 per barrel in North America in 2002, $3.23 in 2001 and $1.91 in 2000. North American product sales volumes increased 1% to a record 176,427 barrels per day in 2002, following a 17% increase in 2001. Sales volumes through the Company's retail gasoline network at Wal-Mart stores continued to grow steadily throughout 2002, but lower sales volumes into the wholesale market, caused by lower finished products produced by the Company's refineries, mostly offset this increase. Higher product sales volumes in 2001 was attributable to a combination of higher crude oil throughputs compared to the previous year at the Company's U.S. refineries, plus continued expansion of the Company's retail gasoline network at Wal-Mart stores.

Unit margins in the United Kingdom averaged $1.70 per barrel in 2002, $3.29 in 2001 and $4.69 in 2000. Sales of petroleum products were up 10% in 2002 to 34,204 barrels per day, while 2001 volumes were 4% higher than 2000, with both years' increases caused by higher volumes sold in the cargo market.

Both U.S. and U.K. operations were experiencing losses during January 2003 due to unit margins being significantly weaker during this period compared to the 2002 average.

Based on sales volumes for 2002 and deducting taxes at marginal rates, each $.42 per barrel ($.01 per gallon) fluctuation in the unit margins would have affected annual refining and marketing profits by $20.5 million. The effect of these unit margin fluctuations on consolidated net income cannot be measured because operating results of the Company's exploration and production segments could be affected differently.

Corporate – The costs of corporate activities, which include interest income and expense and corporate overhead not allocated to operating functions, were $23.6 million in 2002, $12.8 million in 2001 and $1.7 million in 2000. The higher net cost in 2002 compared to 2001 was due to a combination of more net interest expense associated with higher borrowings and lower interest income earned. Net costs were higher in 2001 than in 2000 mainly because the earlier year included more income tax benefits and associated interest income from settlement of prior year tax matters.

Capital Expenditures

As shown in the selected financial data on page 8 of this Form 10-K report, capital expenditures, including discretionary exploration expenditures, were $868.1 million in 2002 compared to $864.4 million in 2001 and $557.9 million in 2000. These amounts included $134.8 million, $133.8 million and $111.5 million of exploration costs that were expensed. Capital expenditures for exploration and production activities totaled $631.8 million in 2002, 73% of the Company's total capital expenditures for the year. Exploration and production capital expenditures in 2002 included $18.5 million for acquisition of undeveloped leases, $232.4 million for exploration activities, and $380.9 million for development projects. Development expenditures included $149.4 million for development of deepwater discoveries in the Gulf of Mexico; $27.4 million for the Terra Nova and Hibernia oil fields, offshore Newfoundland; $54.1 million for expansion of synthetic oil operations at the Syncrude project in Canada; and $58.9 million for heavy oil and natural gas projects in western Canada. Exploration and production capital expenditures are shown by major operating area on page F-35 of this Form 10-K report.

Refining and marketing capital expenditures totaled $234.7 million in 2002, compared to $175.2 million in 2001 and $153.8 million in 2000. These amounts represented 27%, 20% and 28% of total capital expenditures of the Company in 2002, 2001 and 2000, respectively. Refining capital spending was $150.1 million in 2002, compared to $88.9 million in 2001 and $23.5 million in 2000. The Company is in the process of expanding its Meraux, Louisiana refinery by building a hydrocracker unit to meet future clean fuel specifications and is also increasing the crude oil processing capacity of the plant from 100,000 barrels of crude oil per day to 125,000 barrels per day. This project is to be completed by the end of the third quarter of 2003. Capital expenditures related to this expansion project amounted to $116.2 million in 2002 and $55.1 million in 2001. Marketing expenditures amounted to $84.6 million in 2002, $86.3 million in 2001 and $100.9 million in 2000. The majority of marketing expenditures in each year was related to construction of retail gasoline stations at Wal-Mart sites in 21 states in the U.S. The Company began building gasoline stations at Wal-Mart stores in Canada in 2002. The Company opened 125 total stations in the U.S. and Canada in 2002, 111 in 2001 and 131 in 2000. The Company acquired the minority interest in the Manito pipeline in 2000 at a cost of approximately $27 million. The Manito pipeline as well as other Canadian pipeline and trucking assets were sold in May 2001.

Cash Flows

Cash provided by continuing operations was $527 million in 2002, $630.6 million in 2001 and $738.1 million in 2000. Nonrecurring items decreased cash flow from continuing operations by $3.4 million in 2002, $32.3 million in 2001 and $2.7 million in 2000. The reductions in cash flow from nonrecurring items in 2002 and 2001 were mainly caused by cash income taxes related to gains on sale of assets. Changes in operating working capital other than cash and cash equivalents required cash of $24.2 million in 2002 and $28 million in 2001, but provided cash of $66 million in 2000. Cash provided by operating activities was further reduced by expenditures for refinery turnarounds and abandonment of oil and gas properties totaling $15.2 million in 2002, $16.4 million in 2001 and $16.6 million in 2000.

Cash proceeds from property sales were $68.1 million in 2002, $173 million in 2001 and $20.7 million in 2000. Borrowings under notes payable and other long-term debt provided $407.6 million of cash in 2002, $88.2 million in 2001 and $175 million in 2000. Cash proceeds from stock option exercises and employee stock purchase plans amounted to $25.1 million in 2002, $18.9 million in 2001 and $3.8 million in 2000.

Property additions and dry hole costs required $834.1 million of cash in 2002, $810.2 million in 2001 and $512.3 million in 2000. Cash outlays for debt repayment during the three years included $57.8 million in 2002, $77.7 million in 2001 and $130.5 million in 2000. The acquisition of Beau Canada in November 2000 utilized $127.5 million of cash. Cash used for dividends to stockholders was $70.9 million in 2002, $67.8 million in 2001 and $65.3 million in 2000. The Company raised its annualized dividend rate from $.75 per share to $.80 per share beginning in the third quarter of 2002.

Financial Condition

Year-end working capital totaled $136.3 million in 2002, $38.6 million in 2001 and $71.7 million in 2000. The current level of working capital does not fully reflect the Company’s liquidity position as the carrying values for inventories under last-in first-out accounting were $129 million below current cost at December 31, 2002. Cash and cash equivalents at the end of 2002 totaled $165 million compared to $82.7 million a year ago and $132.7 million at the end of 2000.

Long-term debt increased by $342 million during 2002 to $862.8 million at the end of the year, 35.1% of total capital employed, and included $74.3 million of nonrecourse debt incurred in connection with the acquisition and development of the Hibernia oil field. The increase in long-term debt in 2002 was attributable to new borrowings associated with the Company’s capital expenditure program, including deepwater Gulf of Mexico development projects, continued expansion of the Syncrude plant and an expansion project at the Company’s Meraux, Louisiana refinery. Long-term debt totaled $520.8 million at the end of 2001 compared to $524.8 million at December 31, 2000. Stockholders’ equity was $1.6 billion at the end of 2002 compared to $1.5 billion a year ago and $1.3 billion at the end of 2000. A summary of transactions in stockholders’ equity accounts is presented on page F-5 of this Form 10-K report.

Murphy had commitments of $623 million for capital projects in progress at December 31, 2002, including $82.1 million related to clean fuels and crude throughput expansion projects at the Meraux refinery; $126.3 million for costs to develop deepwater Gulf of Mexico fields, including Medusa, Front Runner and Habanero; $110.2 million for continued expansion of synthetic oil operations in Canada; and $121.8 million for future combined work commitments in Malaysia and offshore Nova Scotia. The expansion projects at the Meraux refinery include construction of a hydrocracker unit that will allow the refinery to produce low-sulfur products, an expansion of the crude oil processing capacity from 100,000 barrels per day to 125,000 barrels per day, and construction of an additional sulfur recovery complex. See further discussion regarding the Meraux projects on page 4 of this Form 10-K report.

The primary sources of the Company’s liquidity are internally generated funds, access to outside financing and working capital. The Company typically relies on internally generated funds to finance the major portion of its capital and other expenditures, but maintains lines of credit with banks and borrows as necessary to meet spending requirements. The Company anticipates that long-term debt will increase during 2003 because of significant capital expenditure commitments, as described in the preceding paragraph, and an expectation that oil and natural gas prices for much of 2003 will remain below trading ranges experienced in 2002. At December 31, 2002, the Company had access to short-term and long-term revolving credit facilities in the amount of $488 million. 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 equity securities. Current financing arrangements are set forth more fully in Note F to the consolidated financial statements. At February 1, 2003 the Company’s long-term debt rating by Standard and Poor’s was “A-” and by Moody’s was “Baal”. The Company’s ratio of earnings to fixed charges was 3.2 to 1 in 2002, 11.3 to 1 in 2001 and 13.4 to 1 in 2000.

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 Clean Air Act, as amended
- The Federal Water Pollution Control Act
- Safe Drinking Water Act
- Regulations of the United States Department of the Interior governing offshore oil and gas operations

These acts and their associated regulations set limits on emissions and, in the case of discharges to water, establish water quality limits. They also, in most cases, require permits in association with new or modified operations. Many states also have similar statutes and regulations governing air and water, which in some cases impose additional and more stringent requirements. Murphy is also subject to certain acts and regulations primarily governing remediation of wastes or oil spills. The applicable acts are:

- The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), commonly referred to as Superfund, and comparable state statutes. CERCLA 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.
- The Resource Conservation and Recovery Act of 1976, as amended, 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.
- The Oil Pollution Act of 1990, as amended, under which 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. Pursuant to the authority of the Clean Air Act (CAA), the Environmental Protection Agency (EPA) has issued several standards applicable to the formulation of motor fuels, which are designed to reduce emissions of certain air pollutants when the fuel enters commerce or is used. Pursuant to state laws corresponding to the CAA, several states have passed similar or more stringent regulations governing the formulation of motor fuels.

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, 11 terminals, and approximately 80 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; this cost is generally provided for within the Company's liability for accrued dismantlement costs.

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. If regulatory authorities require more costly alternatives than the proposed processes, future expenditures could exceed the accrued liability by up to an estimated $3 million.

The Company has received notices from the U.S. Environmental Protection Agency (EPA) that it is currently considered 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. At one site the Company has agreed to pay $8,100 to obtain a release from further obligations. The Company's insurance carrier has agreed to reimburse the $8,100. Based on currently available information, the Company has reason to believe that it is also a *de minimus* party as to ultimate responsibility at the other Superfund site. 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 one remaining site or other Superfund sites. The Company does not believe that the ultimate costs to clean-up the two Superfund sites will have a material adverse effect on its net income or cash flows 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 future earnings or cash flows.

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, 2002.

The Company's refineries also incur costs to handle and dispose of hazardous waste and other chemical substances. The types of waste and substances disposed of generally fall into the following categories: spent catalysts (usually hydrotreating catalysts); spent/used filter media; tank bottoms and API separator sludge; contaminated soils, laboratory and maintenance spent solvents; and various industrial debris. The costs of disposing of these substances are expensed as incurred and amounted to $3.3 million in 2002. 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 $166 million in 2002 and are projected to be $120 million in 2003.

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 were strong during late 2002 and early 2003, prices for oil field goods and services could be adversely affected in the future. Due to the volatility of oil and natural gas prices, it is not possible to determine what effect these prices will have on the future cost of oil field goods and services.

Accounting changes and recent accounting pronouncements – As described in Note B on page F-10 of this Form 10-K report, Murphy adopted Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS No. 138, effective January 1, 2001. In addition, the Company adopted a change in accounting for unsold crude oil production effective January 1, 2000 that resulted in an $8.7 million charge to earnings in 2000 for the cumulative effect of the accounting change.

In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*. SFAS No. 141 requires that all future business combinations be accounted for using the purchase method of accounting and that certain acquired intangible assets in a business combination be recognized and reported as assets apart from goodwill. SFAS No. 142 requires that amortization of goodwill be replaced with annual tests for impairment and that intangible assets other than goodwill be amortized over their useful lives. The Company adopted SFAS No. 141 upon its issuance and adopted SFAS No. 142 on January 1, 2002. The Company had unamortized goodwill of $51 million at December 31, 2002, which has been tested for impairment as required by SFAS No. 142 at year-end 2002. Amortization expense related to goodwill was $3.1 million for the year ended December 31, 2001.

In October 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which supercedes SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of*, and the accounting and reporting provisions of APB Opinion No. 30, *Reporting the Results of Operations–Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual, and Infrequently Occurring Events and Transactions*. The Company adopted the provision of SFAS No. 144 effective January 1, 2002. The adoption of SFAS No. 144 had no impact on the Company. In the fourth quarter 2002, the Company sold its interest in Ship Shoal Block 113 at a gain of $10.6 million. Following the guidance of SFAS No. 144, Murphy has recorded the gain on disposal, plus the normal operating results, of Ship Shoal Block 113 as discontinued operations for all years presented.

The Company adopted Emerging Issues Task Force (EITF) Issue 02-3 in the fourth quarter 2002. This consensus requires that the results of energy trading activities be recorded on a net margin basis. Accordingly, Murphy has reflected the results of its crude oil trading activities as net revenue in its income statement, and previously reported revenues and cost of sales have been reduced by equal and offsetting amounts, with no changes to net income or cash flows. The effect of this reclassification was a net reduction of both net sales and cost of crude oil, natural gas and product purchases by approximately $269 million in 2002, $600 million in 2001 and $1.03 billion in 2000.

In July 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 requires the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability must be recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed in service. When the liability is initially recorded, the Company will increase the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Upon adoption of SFAS No. 143 on January 1, 2003, the Company will recognize transition adjustments for existing asset retirement obligations, long-lived assets and accumulated depreciation, all net of related income tax effects, as the cumulative effect of a change in accounting principle. After adoption, any difference between costs incurred upon settlement of an asset retirement obligation and the recorded liability will be recognized as a gain or loss in the Company's earnings. The Company is unable to estimate the financial statement impact as of January 1, 2003 from adoption of SFAS No. 143.

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections*. SFAS No. 145 amends existing guidance on reporting gains and losses on the extinguishment of debt to prohibit the classification of the gain or loss as extraordinary, as the use of such extinguishments have become part of the risk management strategy of many companies. SFAS No. 145 also amends SFAS No. 13 to require sale-leaseback accounting for certain lease modifications that have economic effects similar to sale-leaseback transactions. The provisions of the Statement related to the rescission of Statement No. 4 is applied in fiscal years beginning after May 15, 2002. Earlier application of these provisions is encouraged. The provisions of the Statement related to Statement No. 13 were effective for transactions occurring after May 15, 2002, with early application encouraged. The adoption of SFAS No. 145 is not expected to have a material effect on the Company's financial statements.

In June 2002, the FASB issues SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies EITF Issue 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity*. The provisions of this Statement are effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. The adoption of SFAS No. 146 is not expected to have a material effect on the Company's financial statements.

In November 2002, the FASB issued Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirement for Guarantees, Including Indirect Guarantees of Indebtedness to Others, an interpretation of FASB Statements No. 5, 57 and 107 and a rescission of FASB Interpretation No. 34.* This Interpretation elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees issued. The Interpretation also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken. The initial recognition and measurement provisions of the Interpretation are applicable to guarantees issued or modified after December 31, 2002 and are not expected to have a material effect on the Company's financial statements. The disclosure requirements are effective for financial statements of interim and annual periods ending after December 15, 2002.

In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation – Transition and Disclosure, an amendment of FASB Statement No. 123.* This Statement amends SFAS No. 123, *Accounting for Stock-Based Compensation,* to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements. Certain of the disclosure modifications are required for fiscal years ending after December 15, 2002 and are included in the notes to these consolidated financial statements.

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*. This Interpretation addresses the consolidation by business enterprises of variable interest entities as defined in the Interpretation. The Interpretation applies immediately to variable interests in variable interest entities created after January 31, 2003, and to variable interests in variable interest entities obtained after January 31, 2003. For public enterprises with a variable interest in a variable interest entity created before February 1, 2003, the Interpretation is applied no later than the beginning of the first interim reporting period beginning after June 15, 2003. The application of this Interpretation is not expected to have a material effect on the Company's financial statements. The Interpretation requires certain disclosures in financial statements issued after January 31, 2003 if it is reasonably possible that the Company will consolidate or disclose information about variable interest entities when the Interpretation becomes effective.

Significant accounting policies – In preparing the Company's financial statements in accordance with accounting principles generally accepted in the United States, 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. 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. Estimated reserves are often subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of depreciation rates utilized by the Company. 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 and all development capital expenditures 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. The Company also uses proved developed reserves to recognize expense for future estimated dismantlement and abandonment costs. Costs of exploration wells in progress at year-end 2002 were not significant.

- *Impairment of long-lived assets* – The Company continually monitors its long-lived assets recorded in Property, Plant and Equipment and Goodwill in the Consolidated Balance Sheets to make sure that they are fairly presented. The Company must evaluate its properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. Goodwill must be evaluated for impairment at least annually. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the amount of oil and natural gas that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, and future inflation levels. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserves, or other changes to contracts, environmental regulations or tax laws. All of these same factors must be considered when testing a property's carrying value for impairment. The Company can not predict the amount of impairment charges 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 relating to tax operating loss carryforwards and other deductible differences in Ecuador and Malaysia. 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 Ecuador and Malaysia due to management's belief that these assets are not likely to be realized. 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.

- *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, throughput contract, hydrogen supply agreement and capital commitments. Total payments due after 2002 under such contractual obligations are shown below.

	Amounts Due				
(Millions of dollars)	Total	2003	2004-2006	2007-2008	After 2008
Long-term debt	$ 919.9	57.1	257.1	6.6	599.1
Operating leases	190.2	20.5	58.2	37.0	74.5
Throughput contract	26.9	1.5	4.5	3.0	17.9
Hydrogen purchases	79.4	1.3	15.9	10.6	51.6
Capital commitments	623.0	596.2	26.8	—	—
Total	$1,839.4	676.6	362.5	57.2	743.1

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 that expire in future periods is shown below.

		Commitment Expiration per Period			
(Millions of dollars)	Total	2003	2004-2006	2007-2008	After 2008
Financial guarantees	$12.7	.5	1.8	1.3	9.1
Letters of credit	27.8	4.7	5.6	7.7	9.8
Total	$40.5	5.2	7.4	9.0	18.9

Outlook

Prices for the Company's primary products are often quite volatile. During late 2002 and early 2003, crude oil prices increased significantly primarily due to the near-term potential for a conflict between Iraq and a U.S.-led coalition of armed forces coupled with a nationwide oil worker strike in Venezuela that virtually halted oil exports from this OPEC nation. Because of the generally recognized "war premium" built into oil prices in early 2003, earnings and cash flows from the Company's refining and marketing operations remained very weak. Natural gas prices in late 2002 and early 2003 were stronger than the average for 2002, mainly due to a combination of cold weather in the early winter period and lower gas storage levels compared to the same time a year earlier. If a conflict in Iraq occurs, worldwide crude oil prices could change significantly depending on the war's effect on Middle Eastern oil production. In such a volatile environment, constant reassessment of spending plans is required.

The Company's capital expenditure budget for 2003 was prepared during the fall of 2002 and provides for expenditures of $952 million. Of this amount, $734 million or 77%, is allocated for exploration and production. Geographically, 39% of the exploration and production budget is allocated to the United States, including $191 million for development of deepwater projects in the Gulf of Mexico; another 32% is allocated to Canada, including $23 million for natural gas development, $28 million for heavy oil development, $30 million for continued development of the Hibernia and Terra Nova fields, and $69 million for further expansion of synthetic oil operations; 21% is allocated to exploration and development in Malaysia; and the remaining 8% is planned for other areas, including Ecuador and the United Kingdom. Budgeted refining and marketing capital expenditures for 2003 are $216 million, including $201 million in North America and $15 million in the United Kingdom. Planned spending in North America include funds to complete the clean fuels and crude throughput expansion projects at the Meraux refinery and to build over 100 additional gasoline stations at Wal-Mart sites. Capital and other expenditures are under constant review and planned capital expenditures may be adjusted to reflect changes in estimated cash flow during 2003.

Based on the Company's projected capital expenditures in 2003 and continued refining and marketing margins early in the year, a portion of capital expenditures is anticipated to be funded through new long-term borrowings during the year. Murphy's 2003 Budget anticipates an increase in long-term debt of approximately $200 million during the year. Although the Company is actively managing capital expenditures in light of operating cash flows, it is possible that long-term debt could exceed the budgeted year-end 2003 levels, especially if cash flows are adversely affected in the upcoming months by a weakening of oil and natural gas sales prices and continued weak refining and marketing margins such as those experienced in late 2002 and early 2003.

In order to reduce volatility of oil and natural gas prices, the Company has entered into a series of financial contracts that cover approximately 25% of the Company's anticipated 2003 oil and natural gas production. The swap and collar contracts are accounted for as qualified hedges of 2003 sales prices and are more fully described on page 24 of this report.

Murphy's oil and natural gas production profile will continue to grow in 2003. Two new deepwater Gulf of Mexico fields, Medusa and Habanero, will start up in 2003. Also, the West Patricia field in Block SK 309, offshore Sarawak, Malaysia is expected to produce first oil in the second quarter of 2003. A new heavy oil pipeline in Ecuador that is owned by others should be online in late 2003; this should allow the Company's daily production to more than double in this country by year-end 2003. These new fields will more than offset normal production declines at other fields. Total production for 2003 should average 130,000 to 135,000 barrels of oil equivalent per day.

In early 2003, the Company signed a letter of intent to sell its interests in the Ninian and Columba fields in the U.K. North Sea at a price of $36 million. This sale is expected to close in the second quarter 2003.

Murphy Oil and certain of its subsidiaries maintain defined benefit retirement plans covering most of its full-time employees. During 2002, the Company reduced the expected investment return for assets held in its U.S. retirement plans from 8.5% to 8.0%. The Company has decided to reduce its expected return to 7.5% in 2003. Due to a reduction in bond yields during 2002, the Company has also reduced the plans' discount rates from 7.25% in 2002 to 6.75% in 2003. The funded status of the Company's retirement plans was adversely affected over the last two years by changes in assumptions used to calculate plan liabilities and a negative actual return on plan assets. The smoothing effect of current accounting regulations tend to buffer the current year's pension expense from wide swings in liabilities and asset returns. The effect of negative asset returns and liability changes will adversely impact the Company's pension expense in 2003. The Company's annual retirement plan expense is estimated to increase by about $8 million for 2003 compared to 2002. The Company is required to fund payments of $.3 million into one union plan in 2003. Unless asset values recover during the next few years, the Company's pension expense will continue to be adversely affected by negative asset returns experienced in recent years. In addition, the Company could be required to make additional and more significant funding payments to retirement plans in future years.

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.

The Company was a party to interest rate swaps at December 31, 2002 with notional amounts totaling $50 million that were designed to hedge fluctuations in cash flows of a similar amount of variable-rate debt. These swaps mature in 2004. The swaps require the Company to pay an average interest rate of 6.17% over their composite lives, and at December 31, 2002, the interest rate to be received by the Company averaged 1.64%. The variable interest rate received by the Company under each swap contract is repriced quarterly. The Company considers these swaps to be a hedge against potentially higher future interest rates. The estimated fair value of these interest rate swaps was recorded as a liability of $3.8 million at December 31, 2002.

At December 31, 2002, 20% of the Company’s debt had variable interest rates and 4.6% was denominated in Canadian dollars. Based on debt outstanding at December 31, 2002, a 10% increase in variable interest rates would increase the Company’s interest expense in 2003 by approximately $.2 million after including the favorable effect resulting from lower net settlement payments under the aforementioned interest rate swaps. A 10% increase in the exchange rate of the Canadian dollar versus the U.S. dollar would increase interest expense in 2003 by $.9 million for debt denominated in Canadian dollars.

Murphy was a party to natural gas swap agreements at December 31, 2002 for a total notional volume of 9.2 MMBTU that are intended to hedge the financial exposure of its Meraux, Louisiana refinery to fluctuations in the future price of a portion of natural gas to be purchased for fuel during 2004 through 2006. In each month of settlement, the swaps require Murphy to pay an average natural gas price of $2.78 per MMBTU and to receive the average NYMEX price for the final three trading days of the month. At December 31, 2002, the estimated fair value of these agreements was recorded as an asset of $12.4 million. A 10% increase in the average NYMEX price of natural gas would have increased this asset by $3.7 million, while a 10% decrease would have reduced the asset by a similar amount.

The Company was a party to natural gas swap agreements and natural gas collar agreements at December 31, 2002 that are intended to hedge the financial exposure of a limited portion of its 2003 U.S. and Canadian natural gas production to changes in gas sales prices. The swap agreements are for a combined notional volume that averages 24,200 MMBTU per day and require Murphy to pay the average relevant index price for each month and receive an average price of $3.76 per MMBTU. The collar agreements are for a combined notional volume of 26,700 MMBTU per day and based upon the relevant index prices provide Murphy with an average floor price of $3.24 per MMBTU and an average ceiling price of $4.64 per MMBTU. At December 31, 2002, the estimated fair value of these agreements was recorded as a liability of $6.4 million, with the offsetting loss recorded in Accumulated Other Comprehensive Loss (AOCL) in Stockholders’ Equity. A 10% increase in the average index price of natural gas would have increased this liability by $3.7 million, while a 10% decrease would have reduced the liability by a similar amount.

In addition, the Company was a party to crude oil swap agreements at December 31, 2002 that are intended to hedge the financial exposure of a limited portion of its 2003 U.S. and Canadian crude oil production to changes in crude oil sales prices. A portion of the swap agreements cover a notional volume of 22,000 barrels per day of light oil and require Murphy to pay the average of the closing settlement price on the NYMEX for the Nearby Light Crude Futures Contract for each month and receive an average price of $25.30 per barrel. Additionally, there are heavy oil swap agreements with a notional volume of 10,000 barrels per day that require Murphy to pay the arithmetic average of the posted prices for each month at the Kerrobert and Hardisty terminals in Canada and receive an average price of $16.74 per barrel. At December 31, 2002, the estimated fair value of these agreements was recorded as a liability of $19.9 million, with the offsetting loss recorded in AOCL in Stockholders’ Equity. A 10% increase in the average index price of crude oil would have increased this liability by $28 million, while a 10% decrease would have reduced the liability by a similar amount.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages F-1 through F-41, which follow page 31 of this Form 10-K report.

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

None

PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Certain information regarding executive officers of the Company is included on page 6 of this Form 10-K report. Other information required by this item is incorporated by reference to the Registrant's definitive Proxy Statement for the Annual Meeting of Stockholders on May 14, 2003 under the caption "Election of Directors."

Item 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to the Registrant's definitive Proxy Statement for the Annual Meeting of Stockholders on May 14, 2003 under the captions "Compensation of Directors," "Executive Compensation," "Option Exercises and Fiscal Year-End Values," "Option Grants," "Compensation Committee Report for 2002," "Shareholder Return Performance Presentation" and "Retirement Plans."

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

Information required by this item is incorporated by reference to the Registrant's definitive Proxy Statement for the Annual Meeting of Stockholders on May 14, 2003 under the captions "Security Ownership of Certain Beneficial Owners," "Security Ownership of Management," and "Equity Compensation Plan Information."

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None

PART IV

Item 14. CONTROLS AND PROCEDURES

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

Based on their evaluation as of a date within 90 days of 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-14(c) and 15d-14(c) 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.

There were no significant changes in the Company's internal controls or in other factors that could significantly affect those controls subsequent to the date of their most recent evaluation.

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(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. FinancialStatement 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.

Exhibit No.		Incorporated by Reference to
3.1	Certificate of Incorporation of Murphy Oil Corporation as amended, effective May 17, 2001	Exhibit 3.1 of Murphy's Form 10-Q report for the quarterly period ended June 30, 2001
3.2	By-Laws of Murphy Oil Corporation as amended effective May 8, 2002	Exhibit 3.2 of Murphy's Form 10-Q report for the quarterly period ended June 30, 2002
4	Instruments Defining the Rights of Security Holders. Murphy is party to several long-term debt instruments in addition to the one in Exhibit 4.1, 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.	

Exhibit No.		Incorporated by Reference to
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	Exhibits 4.1 and 4.2 of Murphy's Form 8-K report filed April 29, 1999 under the Securities Exchange Act of 1934
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, 1999
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 3 of Murphy's Form 8-A/A, Amendment No. 1, filed April 14, 1998 under the Securities Exchange Act of 1934
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 of Murphy's Form 8-A/A, Amendment No. 2, filed April 19, 1999 under the Securities Exchange Act of 1934
*10.1	1992 Stock Incentive Plan as amended May 14, 1997	
10.2	Employee Stock Purchase Plan as amended May 10, 2000	Exhibit 99.01 of Murphy's Form S-8 Registration Statement filed August 4, 2000 under the Securities Act of 1933
*10.3	Motor Vehicle Fueling Station Master Ground Lease Agreement	
*12.1	Computation of Ratio of Earnings to Fixed Charges	
*13	2002 Annual Report to Security Holders including Narrative to Graphic and Image Material as an appendix	
*21	Subsidiaries of the Registrant	
*23	Independent Auditors' Consent	
*99.1	Undertakings	
*99.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	
*99.3	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	

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Exhibit No.		Incorporated by Reference to
#99.4	Form 11-K, Annual Report for the fiscal year ended December 31, 2002 covering the Thrift Plan for Employees of Murphy Oil Corporation	To be filed as an amendment to this Form 10-K report not later than 180 days after December 31, 2002
#99.5	Form 11-K, Annual Report for the fiscal year ended December 31, 2002 covering the Thrift Plan for Employees of Murphy Oil USA, Inc. Represented by United Steelworkers of America, AFL-CIO, Local No. 8363	To be filed as an amendment to this Form 10-K report not later than 180 days after December 31, 2002
#99.6	Form 11-K, Annual Report for the fiscal year ended December 31, 2002 covering the Thrift Plan for Employees of Murphy Oil USA, Inc. Represented by International Union of Operating Engineers, AFL-CIO, Local No. 305	To be filed as an amendment to this Form 10-K report not later than 180 days after December 31, 2002

(b) Reports on Form 8-K

A report on form 8-K was filed on December 5, 2002 announcing that the Board of Directors of the Company had declared a two-for-one stock split of the common stock of Murphy Oil Corporation effective December 30, 2002.

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

I, Claiborne P. Deming, certify that:

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

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

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

    b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

    c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

    a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 21, 2003

/s/ Claiborne P. Deming

Claiborne P. Deming
Principal Executive Officer

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

I, Steven A. Cossé, certify that:

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

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

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

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 21, 2003

/s/ Steven A. Cossé

Steven A. Cossé
Principal Financial Officer

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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	Date:	March 21, 2003
	Claiborne P. Deming, President		

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on March 21, 2003 by the following persons on behalf of the registrant and in the capacities indicated.

WILLIAM C. NOLAN JR.	R. MADISON MURPHY
William C. Nolan Jr., Chairman and Director	R. Madison Murphy, Director
CLAIBORNE P. DEMING	DAVID J. H. SMITH
Claiborne P. Deming, President and Chief Executive Officer and Director (Principal Executive Officer)	David J. H. Smith, Director
GEORGE S. DEMBROSKI	CAROLINE G. THEUS
George S. Dembroski, Director	Caroline G. Theus, Director
H. RODES HART	STEVEN A. COSSÉ
H. Rodes Hart, Director	Steven A. Cossé, Senior Vice President and General Counsel (Principal Financial Officer)
ROBERT A. HERMES	JOHN W. ECKART
Robert A. Hermes, Director	John W. Eckart, Controller (Principal Accounting Officer)

REPORT OF MANAGEMENT

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 generally accepted U.S. accounting principles appropriate in the circumstances and include some amounts based on informed estimates and judgments, with consideration given to materiality.

Management is also responsible for maintaining a system of internal accounting controls designed to provide reasonable, but not absolute, assurance that financial information is objective and reliable by ensuring that all transactions are properly recorded in the Company's accounts and records, written policies and procedures are followed and assets are safeguarded. The system is also supported by careful selection and training of qualified personnel. When establishing and maintaining such a system, judgment is required to weigh relative costs against expected benefits. The Company's audit staff independently and systematically evaluates and formally reports on the adequacy and effectiveness of the internal control system.

Our independent auditors, KPMG LLP, have audited the consolidated financial statements. Their audit was conducted in accordance with auditing standards generally accepted in the United States of America and provides an independent opinion about the fair presentation of the consolidated financial statements. When performing their audit, KPMG LLP considers the Company's internal control structure to the extent they deem necessary to issue their opinion on the financial statements. The Board of Directors appoints the independent auditors; 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 outside auditors. This Committee is composed solely of directors who are not employees of the Company. The Committee meets periodically with representatives of management, the Company's audit staff and the independent auditors to review and discuss the adequacy and effectiveness of the Company's internal controls, the quality and clarity of its financial reporting, and the scope and results of independent and internal audits, and to fulfill other responsibilities included in the Committee's Charter. The independent auditors and the Company's audit staff have unrestricted access to the Committee, without management presence, to discuss audit findings and other financial matters.

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Stockholders of Murphy Oil Corporation:

We have audited the accompanying consolidated balance sheets of Murphy Oil Corporation and Consolidated Subsidiaries as of December 31, 2002 and 2001, 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, 2002. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 Consolidated Subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note B to the consolidated financial statements, effective January 1, 2002, the Company changed its method of accounting for goodwill and other intangible assets and effective January 1, 2001, the Company changed its method of accounting for derivative instruments and hedging activities.

Shreveport, Louisiana
February 14, 2003

KPMG LLP

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 (Thousands of dollars except per share amounts)	2002	2001*	2000*
Revenues			
Sales and other operating revenues	$ 3,966,516	3,743,986	3,630,195
Gain on sale of assets	9,148	105,504	4,010
Interest and other income	8,663	16,478	23,981
Total revenues	3,984,327	3,865,968	3,658,186
Costs and Expenses			
Crude oil, natural gas and product purchases	2,676,012	2,370,550	2,324,591
Operating expenses	540,019	479,336	412,822
Exploration expenses, including undeveloped lease amortization	159,429	156,919	125,629
Selling and general expenses	98,562	97,835	85,474
Depreciation, depletion and amortization	300,022	226,621	210,906
Amortization of goodwill	—	3,120	—
Impairment of properties	31,640	10,478	27,916
Interest expense	51,504	39,289	29,936
Interest capitalized	(24,536)	(20,283)	(13,599)
Total costs and expenses	3,832,652	3,363,865	3,203,675
Income from continuing operations before income taxes	151,675	502,103	454,511
Income tax expense	54,165	173,673	155,985
Income from continuing operations	97,510	328,430	298,526
Discontinued operations, net of tax (including gain on disposal in 2002 of $10,650)	13,998	2,473	7,035
Cumulative effect of accounting change, net of tax (Note B)	—	—	(8,733)
Net Income	$ 111,508	330,903	296,828
Income (Loss) per Common Share – Basic			
Income from continuing operations	$ 1.07	3.63	3.32
Discontinued operations	.15	.03	.08
Cumulative effect of accounting change	—	—	(.10)
Net Income – Basic	$ 1.22	3.66	3.30
Income (Loss) per Common Share – Diluted			
Income from continuing operations	$ 1.06	3.60	3.30
Discontinued operations	.15	.03	.08
Cumulative effect of accounting change	—	—	(.10)
Net Income – Diluted	$ 1.21	3.63	3.28
Average Common shares outstanding – basic	91,450,836	90,442,944	90,063,330
Average Common shares outstanding – diluted	92,134,967	91,181,998	90,479,412

* Reclassified to conform to 2002 presentation.

See notes to consolidated financial statements, page F-7.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

December 31 (Thousands of dollars)	2002	2001
Assets		
Current assets		
Cash and cash equivalents	$ 164,957	82,652
Accounts receivable, less allowance for doubtful accounts of $9,307 in 2002 and $11,263 in 2001	408,782	262,022
Inventories, at lower of cost or market		
Crude oil and blend stocks	41,961	38,917
Finished products	94,158	85,133
Materials and supplies	65,225	49,098
Prepaid expenses	59,962	61,062
Deferred income taxes	19,115	19,777
Total current assets	854,160	598,661
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $3,361,726 in 2002 and $3,277,673 in 2001	2,886,599	2,525,807
Goodwill, net	51,037	50,412
Deferred charges and other assets	93,979	84,219
Total assets	$ 3,885,775	3,259,099
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long-term debt	$ 57,104	48,250
Accounts payable	447,740	325,323
Income taxes	61,559	48,378
Other taxes payable	97,770	86,844
Other accrued liabilities	53,719	51,262
Total current liabilities	717,892	560,057
Notes payable	788,554	416,061
Nonrecourse debt of a subsidiary	74,254	104,724
Deferred income taxes	327,771	302,868
Accrued dismantlement costs	160,543	160,764
Accrued major repair costs	52,980	44,570
Deferred credits and other liabilities	170,228	171,892
Stockholders' equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued	—	—
Common Stock, par $1.00, authorized 200,000,000 shares at December 31, 2002 and 2001, issued 94,613,379 and 48,775,314 shares at December 31, 2002 and 2001, respectively	94,613	48,775
Capital in excess of par value	504,983	527,126
Retained earnings	1,137,177	1,096,567
Accumulated other comprehensive loss	(66,790)	(83,309)
Unamortized restricted stock awards	—	(968)
Treasury stock	(76,430)	(90,028)
Total stockholders' equity	1,593,553	1,498,163
Total liabilities and stockholders' equity	$ 3,885,775	3,259,099

See notes to consolidated financial statements, page F-7.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 (Thousands of dollars)	2002	2001*	2000*
Operating Activities			
Income from continuing operations	$ 97,510	328,430	298,526
Adjustments to reconcile above income to net cash provided by operating activities			
Depreciation, depletion and amortization	300,022	226,621	210,906
Impairment of properties	31,640	10,478	27,916
Provisions for major repairs	24,996	21,070	22,761
Expenditures for major repairs and dismantlement costs	(15,188)	(16,395)	(16,603)
Dry hole costs	101,201	82,825	65,987
Amortization of undeveloped leases	24,634	23,154	14,076
Amortization of goodwill	—	3,120	—
Deferred and noncurrent income tax charges	5,871	80,052	63,431
Pretax gains from disposition of assets	(9,148)	(105,504)	(4,010)
Net (increase) decrease in noncash operating working capital excluding acquisition of Beau Canada Exploration Ltd.	(24,213)	(27,951)	66,002
Cumulative effect of accounting change on working capital	—	—	(11,170)
Other operating activities – net	(10,356)	4,731	261
Net cash provided by continuing operations	526,969	630,631	738,083
Net cash provided by discontinued operations	5,875	5,073	9,668
Net cash provided by operating activities	532,844	635,704	747,751
Investing Activities			
Property additions and dry hole costs	(834,056)	(810,152)	(512,331)
Acquisition of Beau Canada Exploration Ltd., net of cash acquired	—	—	(127,476)
Proceeds from sale of property, plant and equipment	68,056	172,972	20,705
Other investing activities – net	(2,177)	(1,410)	391
Investing activities of discontinued operations	6,731	(3,348)	—
Net cash required by investing activities	(761,446)	(641,938)	(618,711)
Financing Activities			
Additions to notes payable	407,053	87,000	175,000
Reductions of notes payable	(32,457)	(62,214)	(124,254)
Additions to nonrecourse debt of a subsidiary	573	1,241	—
Reductions of nonrecourse debt of a subsidiary	(25,354)	(15,499)	(6,207)
Proceeds from exercise of stock options and employee stock purchase plans	25,131	18,864	3,769
Cash dividends paid	(70,898)	(67,826)	(65,294)
Other financing activities – net	(2,778)	(3,050)	(7,894)
Net cash provided (required) by financing activities	301,270	(41,484)	(24,880)
Effect of exchange rate changes on cash and cash equivalents	9,637	(2,331)	(5,591)
Net increase (decrease) in cash and cash equivalents	82,305	(50,049)	98,569
Cash and cash equivalents at January 1	82,652	132,701	34,132
Cash and cash equivalents at December 31	$ 164,957	82,652	132,701

* Reclassified to conform to 2002 presentation.

See notes to consolidated financial statements, page F-7.

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

Years Ended December 31 (Thousands of dollars)	2002	2001	2000
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	—	—	—
Common Stock – par $1.00, authorized 200,000,000 shares at December 31, 2002 and 2001 and 80,000,000 shares at December 31, 2000, issued 94,613,379 shares at December 31, 2002 and 48,775,314 shares at beginning and end of 2001 and 2000			
Balance at beginning of year	$ 48,775	48,775	48,775
Two-for-one stock split effective December 30, 2002	45,838	—	—
Balance at end of year	94,613	48,775	48,775
Capital in Excess of Par Value			
Balance at beginning of year	527,126	514,474	512,488
Exercise of stock options, including income tax benefits	20,039	10,440	1,749
Restricted stock transactions	2,563	1,272	(202)
Sale of stock under employee stock purchase plans	1,093	940	439
Two-for-one stock split effective December 30, 2002	(45,838)	—	—
Balance at end of year	504,983	527,126	514,474
Retained Earnings			
Balance at beginning of year	1,096,567	833,490	601,956
Net income for the year	111,508	330,903	296,828
Cash dividends – $.775 per share in 2002, $.75 per share in 2001and $.725 per share in 2000	(70,898)	(67,826)	(65,294)
Balance at end of year	1,137,177	1,096,567	833,490
Accumulated Other Comprehensive Loss			
Balance at beginning of year	(83,309)	(38,266)	(4,984)
Foreign currency translation gains (losses)	30,878	(49,596)	(33,282)
Cash flow hedging gains (losses), net of income taxes	(13,007)	4,553	—
Minimum pension liability, net of income taxes	(1,352)	—	—
Balance at end of year	(66,790)	(83,309)	(38,266)
Unamortized Restricted Stock Awards			
Balance at beginning of year	(968)	(1,410)	(2,328)
Amortization, forfeitures and changes in price of Common Stock	968	442	918
Balance at end of year	—	(968)	(1,410)
Treasury Stock			
Balance at beginning of year	(90,028)	(97,503)	(98,735)
Exercise of stock options	12,852	6,833	1,140
Sale of stock under employee stock purchase plans	749	651	441
Awarded restricted stock, net of forfeitures, and other	(3)	(9)	(349)
Balance at end of year – 2,923,925 shares of Common Stock in 2002, 3,444,234 shares in 2001 and 3,729,769 shares in 2000	(76,430)	(90,028)	(97,503)
Total Stockholders' Equity	$ 1,593,553	1,498,163	1,259,560

See notes to consolidated financial statements, page F-7.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 (Thousands of dollars)	2002	2001	2000
Net income	$ 111,508	330,903	296,828
Other comprehensive income (loss), net of tax			
Cash flow hedges			
Net derivative gains (losses)	(8,065)	26	—
Reclassification adjustments	(4,942)	(2,115)	—
Total cash flow hedges	(13,007)	(2,089)	—
Net gain (loss) from foreign currency translation	30,878	(49,596)	(33,282)
Minimum pension liability adjustment, net of tax	(1,352)	—	—
Other comprehensive income (loss) before cumulative effect of accounting change	16,519	(51,685)	(33,282)
Cumulative effect of accounting change (Note B)	—	6,642	—
Other comprehensive income (loss)	16,519	(45,043)	(33,282)
Comprehensive Income	$ 128,027	285,860	263,546

See notes to consolidated financial statements, page F-7.

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 natural gas in the United States, Canada, the United Kingdom and Ecuador and conducts 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. Investments in affiliates in which the Company owns from 20% to 50% are accounted for by the equity method. Other investments are generally carried at cost. All significant intercompany accounts and transactions have been eliminated.

REVENUE RECOGNITION – Revenues from sales of crude oil, natural gas and refined petroleum products are recorded when deliveries have occurred and legal ownership of the commodity transfers to the customer. Title transfers for crude oil, natural gas and bulk refined products generally occur at pipeline custody points or when a tanker lifting has occurred. Refined products sold at retail are recorded when the customer takes delivery at the pump. Revenues from the production of oil and natural gas properties in which Murphy shares an undivided interest with other producers are recognized based on the actual volumes sold by the Company during the period. Oil and gas imbalances occur when the Company's actual sales differ from its entitlement under existing working interests. The Company records a liability for oil and gas imbalances when it has sold more than its working interest of oil and gas production and the estimated remaining reserves make it doubtful that partners can recoup their share of production from the field. At December 31, 2002 and 2001, no liabilities for oil balancing existed and 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. See Note B regarding adoption of Emerging Issues Task Force (EITF) Issue 02-3 in the fourth quarter 2002.

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.

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. Cost of exploratory drilling is initially capitalized but is subsequently expensed if proved reserves are not found. Other exploratory costs are charged to expense as incurred. Development costs, including unsuccessful development wells, are capitalized.

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

Depreciation and depletion of producing oil and gas properties are recorded based on units of production. Unit rates are computed for unamortized exploration drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. As more fully described on page F-32 of this Form 10-K report, proved reserves are estimated by the Company's engineers and are subject to future revisions based on availability of additional information. Estimated dismantlement, abandonment and site restoration costs, net of salvage value, are generally recognized using the units of production method and are included in depreciation expense. Costs for future dismantlement, abandonment and site restoration are estimated by the Company's engineers using existing regulatory requirements and anticipated future inflation rates. 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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Gains and losses on disposals or retirements that are significant or include an entire depreciable or depletable property unit are included in income. Actual costs of dismantling oil and gas production facilities and site restoration are charged against the related liability. All other dispositions, retirements or abandonments are reflected in accumulated depreciation, depletion and amortization.

Full plant turnarounds for major processing units are scheduled at 4-1/2 year intervals at the Meraux, Louisiana refinery and 5 year intervals at the Superior, Wisconsin refinery. Turnarounds at the Milford Haven, Wales refinery are scheduled on a 4 year cycle. Turnarounds for coking units at Syncrude Canada Ltd. are scheduled at intervals of 2 to 3 years. Turnaround work associated with various other less significant units at the Company's refineries and Syncrude will occur during the interim period and will vary depending on operating requirements and events. Murphy accrues in advance for estimated costs of these turnarounds by recording monthly expense provisions. Future major repair costs are estimated by the Company's engineers. Actual costs incurred are charged against the accrued liability. All other maintenance and repairs are expensed. Renewals and betterments are capitalized.

INVENTORIES – Inventories of crude oil other than refinery feedstocks are valued at the lower of cost, generally applied on a first-in first-out (FIFO) basis, or market. Refinery inventories of crude oil and other feedstocks and finished product inventories are valued at the lower of cost, generally applied on a last-in first-out (LIFO) basis, or market. Materials and supplies are valued at the lower of average cost or estimated value.

GOODWILL – The excess of the purchase price over the fair value of net assets acquired associated with the purchase of Beau Canada Exploration Ltd. (Beau Canada) was recorded as goodwill. Through 2001, goodwill was amortized on a straight-line basis over 15 years, and its recoverability was assessed by determining whether future goodwill amortization can be recovered through undiscounted future net cash flows for western Canadian oil and gas properties. Effective January 1, 2002, in accordance with Statement of Financial Accounting Standards (SFAS) No. 142, *Goodwill and Other Intangible Assets*, goodwill is no longer amortized. SFAS No. 142 requires an annual assessment of recoverability of the carrying value of goodwill. Beginning in 2002, the Company has assessed goodwill recoverability 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. 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 provision for environmental obligations is charged to expense when the Company's liability for an environmental assessment and/or cleanup is probable and the cost can be reasonably estimated. 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 the majority of activities in the United Kingdom. The U.S. dollar is the functional currency used to record all other operations. Gains or losses from translating foreign functional currency into U.S. dollars are included in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets. Exchange gains or losses from transactions in a currency other than the functional currency are included in income.

DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES – Effective January 1, 2001, the Company adopted SFAS No. 133, as amended by SFAS No. 138. See also Notes B and K for further information about the Company's derivative instruments. The fair value of a derivative instrument is recognized as an asset or liability in the Company's

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, mark the contract to market through 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 earnings are affected by the cash flows of the hedged item. When the cash flow of the 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 hedging derivative's change in fair value are recognized currently in earnings. If a derivative instrument no longer qualifies as a cash flow hedge, hedge accounting is discontinued and the gain or loss that was recorded in other comprehensive income is recognized immediately in earnings.

STOCK OPTIONS – The Company uses the intrinsic-value based method of accounting as prescribed by Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* and related interpretations to account for its stock options. Under this method, the Company accrues costs of restricted stock and any stock option deemed to be variable in nature over the vesting/performance period and adjusts such costs for changes in the fair market value of Common Stock. No compensation expense is recorded for stock options since all option prices have been equal to or greater than the fair market value of the Company's stock on the date of grant. SFAS No. 123, *Accounting for Stock-Based Compensation*, established accounting and disclosure requirements using a fair-value based method for stock-based employee compensation plans. As allowed by SFAS No. 123, the Company has elected to continue to apply the intrinsic-value based method prescribed by APB No. 25 and has adopted only the disclosure requirements of SFAS No. 123. Had the Company recorded compensation expense for stock options as prescribed by SFAS No. 123, net income and earnings per share would be the pro forma amounts shown in the following table.

(Thousands of dollars except per share data)		2002	2001	2000
Net income	– As reported	$ 111,508	330,903	296,828
	Pro forma	104,192	324,358	299,031
Net income per share	– As reported, basic	$ 1.22	3.66	3.30
	Pro forma, basic	1.14	3.59	3.32
	As reported, diluted	1.21	3.63	3.28
	Pro forma, diluted	1.13	3.56	3.30

NET INCOME PER COMMON SHARE – Basic income per Common share is computed by dividing net income for each reporting period by the weighted average number of Common shares outstanding during the period. Diluted income per Common share is computed by dividing net income for each reporting period by the weighted average number of Common shares outstanding during the period plus the effects of potentially dilutive Common shares. Per share amounts for 2001 and 2000 have been restated to reflect the Company's two-for-one stock split effective December 30, 2002.

USE OF ESTIMATES – In preparing the financial statements of the Company in conformity with accounting principles generally accepted in the United States of America, 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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note B – New Accounting Principles and Recent Accounting Pronouncements

Effective January 1, 2002, the Company was required to adopt the Financial Accounting Standards Board's (FASB) SFAS No. 142, *Goodwill and Other Intangible Assets*, which requires that amortization of goodwill be replaced with annual tests for impairment and that intangible assets other than goodwill be amortized over their useful lives. Murphy assesses the recoverability of goodwill by comparing the fair value of net assets for conventional oil and natural gas operations in Canada with the carrying value of these net assets including goodwill. The fair value of the conventional oil and natural gas reporting unit is determined using the expected present value of future cash flows. The carrying amount of goodwill at December 31, 2002 was $51,037,000. The change in the carrying amount of goodwill at December 31, 2002 compared to December 31, 2001 was due to a change in the exchange rate of Canadian dollars and U.S. dollars. Goodwill is tested for impairment at the end of the Company's fiscal year after the oil and gas reserve information is available. 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. Adjusted net income for the year ended December 31, 2001, excluding goodwill amortization of $3,120,000 ($.03 basic and diluted earnings per share), was $334,023,000. Adjusted basic and diluted earnings per share for the year ended December 31, 2001 were $3.69 and $3.66, respectively.

Effective January 1, 2002, Murphy was required to adopt SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which supercedes SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*, and the accounting and reporting provisions of APB Opinion No. 30, *Reporting the Results of Operations-Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual, and Infrequently Occurring Events and Transactions*. This statement retains the basic requirements for recognition and measurement of impairment losses for long-lived assets to be held and used, but for long-lived assets to be disposed of by sale, it broadens the definition of those disposals that should be reported separately as discontinued operations.

In October 2002, the EITF reached a consensus on certain issues contained in Topic 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. The Company adopted EITF 02-3 in the fourth quarter 2002. This consensus requires that gains and losses on all derivative instruments within the scope of SFAS No. 133 be shown net in the income statement if the derivatives are held for trading purposes. Accordingly, Murphy has reflected the results of its crude oil trading activities net in its income statement and previously reported revenues and cost of sales have been reduced by equal and offsetting amounts with no changes to net income or cash flows. The effect of this reclassification was a net reduction of both Sales and Other Operating Revenues and Crude Oil, Natural Gas and Product Purchases by approximately $269,000,000 in 2002, $600,000,000 in 2001 and $1,030,000,000 in 2000.

Effective January 1, 2001, Murphy adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS No. 138 (SFAS Nos. 133/138). As a result of the change, Murphy records the fair values of its derivative instruments as either assets or liabilities. All such instruments have been designated as hedges of forecasted cash flow exposures. Changes in the fair value of a qualifying cash flow hedging derivative are deferred and recorded as a component of Accumulated Other Comprehensive Loss (AOCL) in the Consolidated Balance Sheet until the forecasted transaction occurs, at which time the derivative's fair value will be recognized in earnings. Ineffective portions of hedging derivative's change in fair value are immediately recognized in earnings. Adoption of SFAS Nos. 133/138 resulted in a transition adjustment gain to AOCL of $6,642,000, net of $2,845,000 in income taxes, for the cumulative effect on prior years; there was no cumulative effect on earnings. The effect of this accounting change decreased AOCL for the year ended December 31, 2002 by $13,007,000, net of $8,885,000 in income taxes, and decreased income by $1,435,000 for the same period. Excluding the transition adjustment in January 2001, the accounting change decreased AOCL for the year ended December 31, 2001 by $2,089,000, net of $398,000 in income taxes, and decreased net income by $69,000, net of taxes. For the years ended December 31, 2002 and 2001, losses of $4,942,000 and $2,115,000, net of $3,267,000 and $765,000 in taxes, respectively, were reclassified from AOCL to income.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In 2000, Murphy adopted the revenue recognition guidance in the Securities and Exchange Commission's Staff Accounting Bulletin 101. As a result of the change, Murphy records revenues related to its crude oil as the oil is sold, and carries its unsold crude oil production at cost rather than market value as in the past. Consequently, Murphy recorded a transition adjustment of $8,733,000, net of income tax benefits of $3,886,000, for the cumulative effect on prior years. Excluding the cumulative effect transition adjustment, this accounting change increased income in 2000 by $1,145,000. The transition adjustment included a cumulative reduction of revenue for years prior to the change of $20,591,000. Pro forma net income for the year ended December 31, 2000, assuming that the new revenue recognition method had been applied retroactively, was as follows.

(Thousands of dollars except per share data)			2000
Net income	–	As reported	$ 296,828
		Pro forma	305,561
Net income per share	–	As reported, basic	$ 3.30
		Pro forma, basic	3.39
		As reported, diluted	3.28
		Pro forma, diluted	3.38

In July 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*, which will require the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability must be recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed in service. When the liability is initially recorded, the Company will increase the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Upon adoption of SFAS No. 143 on January 1, 2003, the Company will recognize transition adjustments for existing asset retirement obligations, long-lived assets and accumulated depreciation, all net of related income tax effects, as the cumulative effect of a change in accounting principle. After adoption, any difference between costs incurred upon settlement of an asset retirement obligation and the recorded liability will be recognized as a gain or loss in the Company's earnings. The Company is unable to estimate the financial statement impact as of January 1, 2003 from adoption of SFAS No. 143.

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections*. SFAS No. 145 amends existing guidance on reporting gains and losses on the extinguishment of debt to prohibit the classification of the gain or loss as extraordinary, as the use of such extinguishments have become part of the risk management strategy of many companies. SFAS No. 145 also amends SFAS No. 13 to require sale-leaseback accounting for certain lease modifications that have economic effects similar to sale-leaseback transactions. The provisions of the Statement related to the rescission of Statement No. 4 is applied in fiscal years beginning after May 15, 2002. Earlier application of these provisions is encouraged. The provisions of the Statement related to SFAS No. 13 were effective for transactions occurring after May 15, 2002, with early application encouraged. The adoption of SFAS No. 145 is not expected to have a material effect on the Company's financial statements.

In June 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies EITF Issue 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity*. The provisions of this Statement are effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. The adoption of SFAS No. 146 is not expected to have a material effect on the Company's financial statements.

In November 2002, the FASB issued Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirement for Guarantees, Including Indirect Guarantees of Indebtedness to Others, an interpretation of FASB Statements No. 5, 57 and 107 and a rescission of FASB Interpretation No. 34.* This Interpretation elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees issued. The Interpretation also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken. The initial recognition and measurement provisions of the Interpretation are applicable to guarantees issued or modified after December 31, 2002 and are not expected to have a material effect on the Company's financial statements. The disclosure requirements are effective for financial statements of interim and annual periods ending after December 31, 2002.

In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation - Transition and Disclosure, an amendment of FASB Statement No. 123*. This Statement amends SFAS No. 123, *Accounting for Stock-Based Compensation*, to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements. Certain of the disclosure modifications are required for fiscal years ending after December 15, 2002 and are included in the notes to these consolidated financial statements.

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51*. This Interpretation addresses the consolidation by business enterprises of variable interest entities as defined in the Interpretation. The Interpretation applies immediately to variable interests in variable interest entities created after January 31, 2003, and to variable interests in variable interest entities obtained after January 31, 2003. For public enterprises with a variable interest in a variable interest entity created before February 1, 2003, the Interpretation is applied no later than the beginning of the first interim reporting period beginning after June 15, 2003. The application of this Interpretation is not expected to have a material effect on the Company's financial statements. The Interpretation requires certain disclosures in financial statements issued after January 31, 2003 if it is reasonably possible that the Company will consolidate or disclose information about variable interest entities when the Interpretation becomes effective.

Note C – Discontinued Operations

In December 2002, the Company sold its investment in Ship Shoal Block 113 in the Gulf of Mexico for an after-tax gain of $10,650,000. The gain, plus normal results of operations for the field prior to the sale, has been reported as Discontinued Operations in the Consolidated Statements of Income for all years presented. The property generated revenues, excluding gain on sale, of $15,515,000 in 2002, $13,410,000 in 2001 and $19,172,000 in 2000. Comparable pretax earnings from the field were $5,151,000 in 2002, $3,805,000 in 2001 and $10,823,000 in 2000.

Note D – Acquisition of Beau Canada Exploration Ltd.

In November 2000, Murphy acquired Beau Canada, an independent oil and natural gas company that primarily owned exploration licenses and producing natural gas and heavy oil fields in western Canada. The acquisition has been accounted for as a purchase. Beau Canada's operations subsequent to the acquisition date have been included in the Company's consolidated financial statements. The Company paid net cash of $127,476,000 to purchase all of Beau Canada's common stock at a price of approximately $1.44 per share.

The Company recorded property, plant and equipment of $260,000,000 associated with the purchase of Beau Canada. The Company valued the property, plant and equipment acquired using both proved and risked probable reserves as estimated by the Company's engineers and an estimate of future oil and natural gas sales prices based on the then prevailing pricing environment for the projected timing of future production.

The Company also assumed debt in the acquisition of $124,227,000 that was repaid by December 31, 2000 through issuance of a structured loan (see Note G). As subsequently adjusted in 2001, Murphy recorded goodwill of $56,280,000 associated with the Beau Canada acquisition, primarily due to the purchase price being greater than the fair value of the net assets acquired and deferred income tax liabilities required to be established in recording the acquisition.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table reflects the unaudited results of operations on a pro forma basis as if the Beau Canada acquisition had been completed at the beginning of 2000. The pro forma financial information is not necessarily indicative of the operating results that would have occurred had the acquisition been consummated as of January 1, 2000, nor is it necessarily indicative of future operating results.

(Thousands of dollars except per share data)	Year Ended December 31, 2000
Pro forma revenues	$3,746,595
Pro forma net income	303,479
Pro forma net income per Common share – diluted	3.35

Note E – Property, Plant and Equipment

	December 31, 2002		December 31, 2001	
(Thousands of dollars)	Cost	Net	Cost	Net
Exploration and production	$ 4,739,856	2,055,187*	4,553,034	1,885,124*
Refining	986,986	451,207	822,339	323,227
Marketing	476,633	354,412	384,520	290,244
Corporate and other	44,850	25,793	43,587	27,212
	$ 6,248,325	2,886,599	5,803,480	2,525,807

* Includes $20,721 in 2002 and $20,174 in 2001 related to administrative assets and support equipment.

In the 2002 and 2001 Consolidated Statements of Income, the Company recorded noncash charges of $31,640,000 and $10,478,000, respectively, for impairment of certain properties. After related income tax benefits, these write-downs reduced net income by $20,567,000 in 2002 and $6,811,000 in 2001. The 2002 charge included $22,487,000 to write-down the remaining cost in Destin Dome Blocks 56 and 57, offshore Florida. In 2002, Murphy reached an agreement with the U.S. government that restricts the Company’s ability to seek approval for development of this natural gas discovery until at least 2012. The additional charges in 2002 and 2001 were caused by downward reserve revisions for poor well performance of natural gas fields in the Gulf of Mexico. The carrying value of impaired properties were reduced to the asset’s fair value based on projected future discounted net cash flows using the Company’s estimate of future commodity prices.

Note F – Financing Arrangements

At December 31, 2002, the Company had three committed credit facilities with a major banking consortium totaling US $488,332,000. The Company and a subsidiary may borrow under a $150,000,000 revolving credit agreement maturing in December 2006. Additionally, the Company and the subsidiary have available a $169,166,000 364-day revolving credit agreement maturing in December 2003 with an option to convert any outstanding amounts to a one-year term loan at maturity. The Company’s Canadian subsidiary has available a US $169,166,000 364-day revolving agreement with an option to convert any outstanding amounts to a five-year and one day term at maturity. The two 364-day revolving credit agreements are extendable for up to 364 days upon approval of a majority of the banking consortium. U.S. dollar and Canadian dollar commercial paper totaling an equivalent US $74,997,000 at December 31, 2002 was outstanding and classified as nonrecourse debt. This outstanding debt is supported by a similar amount of credit facilities with major banks based on loan guarantees from the Canadian government. Depending on the credit facility, borrowings bear interest at prime or varying cost of fund options. Facility fees are due at varying rates on the commitments. The Company also had uncommitted lines of credit with banks at December 31, 2002 totaling an equivalent US $127,323,000 for a combination of U.S. dollar and Canadian dollar borrowings. At December 31, 2002, US $40,200,000 of the committed credit facilities and US $68,000,000 of the uncommitted lines was outstanding and classified as long-term debt based on the ability of the Company to replace this debt with borrowings under the existing long-term credit facilities. 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 equity securities.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note G – Long-term Debt

December 31 (Thousands of dollars)	2002	2001
Notes payable		
6.375% notes, due 2012, net of unamortized discount of $1,072 at December 31, 2002	$ 348,928	—
7.05% notes, due 2029, net of unamortized discount of $2,447 at December 31, 2002	247,553	247,461
6.23% structured loan, due 2003-2005	117,486	149,832
Notes payable to bank, 1.74% to 2.03%, due 2003	108,200	50,000
Other, 6% to 8%, due 2003-2021	1,104	1,187
Total notes payable	823,271	448,480
Nonrecourse debt of a subsidiary		
Guaranteed credit facilities with banks		
Commercial paper, 1.445% to 2.775%, $8,800 payable in Canadian dollars, supported by credit facility, due 2003-2008	74,997	96,476
Loans payable to Canadian government, interest free, payable in Canadian dollars, due 2003-2008	21,644	24,079
Total nonrecourse debt of a subsidiary	96,641	120,555
Total debt including current maturities	919,912	569,035
Current maturities	(57,104)	(48,250)
Total long-term debt	$ 862,808	520,785

Maturities for the four years after 2003 are: $59,055,000 in 2004, $68,760,000 in 2005, $129,271,000 in 2006 and $3,314,000 in 2007.

Notes payable to bank due in 2003 have been classified as long-term debt since the Company is capable of refinancing the borrowing under an existing long-term credit facility.

With the support of a major bank consortium, the structured loan was borrowed by a Canadian subsidiary in December 2000 to replace temporary financing of the Beau Canada acquisition. The 6.23% fixed-rate loan is reduced in quarterly installments. Payment of interest under the loan has been guaranteed by the Company.

The nonrecourse guaranteed credit facilities were arranged to finance certain expenditures for the Hibernia oil field. Subject to certain conditions and limitations, the Canadian government has unconditionally guaranteed repayment of amounts drawn under the facilities to lenders having qualifying Participation Certificates. Additionally, payment is secured by a debenture that mortgages the Company’s share of the Hibernia properties and the production therefrom. Recourse of the lenders is limited to the Canadian government’s guarantee; the government’s recourse to the Company is limited, subject to certain covenants, to Murphy’s interest in the assets and operations of Hibernia. The Company has borrowed the maximum amount available under the Primary Guarantee Facility. The amount guaranteed is reduced quarterly by the greater of 30% of Murphy’s after-tax free cash flow from Hibernia or 1/32 of the original total guarantee. A guarantee fee of .5% is payable annually in arrears to the Canadian government.

The interest-free loans from the Canadian government were also used to finance expenditures for the Hibernia field. The outstanding balance is to be repaid in equal annual installments through 2008.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note H – Income Taxes

The components of income from continuing operations before income taxes for each of the three years ended December 31, 2002 and income tax expense (benefit) attributable thereto were as follows.

(Thousands of dollars)			2002	2001	2000
Income (loss) from continuing operations before income taxes					
United States			$(128,523)	157,251	91,696
Foreign			280,198	344,852	362,815
			$ 151,675	502,103	454,511
Income tax expense (benefit) from continuing operations					
Federal	–	Current[1]	$ (41,531)	28,821	15,427
		Deferred	(1,349)	33,167	5,665
		Noncurrent	(6,824)	(4,136)	(2,261)
			(49,704)	57,852	18,831
State	–	Current	(529)	4,710	3,129
Foreign	–	Current	90,304	60,090	76,184
		Deferred[2]	16,982	50,916	59,776
		Noncurrent	(2,888)	105	(1,935)
			104,398	111,111	134,025
Total			$ 54,165	173,673	155,985

[1] Net of benefit of $10,939 in 2002 and $3,150 in 2000 for alternative minimum tax credits.
[2] Includes a charge of $1,997 in 2002 for an increase in the U.K. tax rate for North Sea oil production and a benefit of $5,540 in 2001 for a reduction in a provincial tax rate in Canada.

Income tax benefits attributable to employee stock option transactions of $3,833,000 in 2002 and $1,685,000 in 2001 were included in Capital in Excess of Par Value in the Consolidated Balance Sheets and income tax (benefits) charges of $(8,885,000) in 2002 and $2,447,000 in 2001 relating to derivatives were included in AOCL.

Total income tax expense in 2002, 2001 and 2000, including taxes associated with discontinued operations and the cumulative effect of accounting change, was $61,702,000, $175,005,000, and $155,887,000, 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)	2002	2001	2000
Income tax expense based on the U.S. statutory tax rate	$ 53,086	175,736	159,079
Foreign income subject to foreign taxes at a rate different than the U.S. statutory rate	11,240	2,498	13,010
State income taxes	(344)	3,062	2,034
Settlement of U.S. taxes	(8,134)	(1,446)	(17,016)
Settlement of foreign taxes	—	(1,915)	—
Changes in foreign tax rates	1,997	(5,540)	—
Other, net	(3,680)	1,278	(1,122)
Total	$ 54,165	173,673	155,985

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2002 and 2001 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	2002	2001
Deferred tax assets		
Property and leasehold costs	$ 101,734	72,390
Liabilities for dismantlements and major repairs	83,072	68,755
Postretirement and other employee benefits	29,595	29,345
Federal alternative minimum tax credit carryforward	10,939	—
Foreign tax operating losses	20,989	26,844
Other deferred tax assets	29,413	22,029
Total gross deferred tax assets	275,742	219,363
Less valuation allowance	(89,574)	(67,745)
Net deferred tax assets	186,168	151,618
Deferred tax liabilities		
Property, plant and equipment	(52,993)	(53,494)
Accumulated depreciation, depletion and amortization	(394,726)	(343,925)
Other deferred tax liabilities	(47,105)	(37,290)
Total gross deferred tax liabilities	(494,824)	(434,709)
Net deferred tax liabilities	$ (308,656)	(283,091)

At December 31, 2002, the Company had tax losses and other carryforwards of $72,735,000 associated with its operations in Ecuador. The losses, available only to Ecuador operations, have a carryforward period of no more than five years, with certain losses limited to 25% of each year's taxable income. These losses expire in 2003 to 2007.

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 in the judgment of management, these tax assets are not likely to be realized. The valuation allowance increased $21,829,000 and $6,787,000 in 2002 and 2001, respectively; the change in each year primarily offset the change in certain deferred tax assets. Any subsequent reductions of the valuation allowance will be reported as reductions of tax expense assuming no offsetting change in the deferred tax asset.

The Company has not recorded a deferred tax liability of $31,584,000 related to undistributed earnings of certain foreign subsidiaries at December 31, 2002 because the earnings are considered permanently invested.

Tax returns are subject to audit by various taxing authorities. In 2002, 2001 and 2000, the Company recorded benefits to income of $14,737,000, $3,361,000 and $25,618,000, respectively, from settlements of U.S. and foreign tax issues primarily related to prior years. Although the Company believes that adequate accruals have been made for unsettled issues, additional gains or losses could occur in future years from resolution of outstanding matters.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note I – Incentive Plans

The Company's 1992 Stock Incentive Plan (the Plan) authorized the Executive Compensation and Nominating Committee (the Committee) to make annual grants of the Company's Common Stock to executives and other key employees as follows: (1) stock options (nonqualified or incentive), (2) stock appreciation rights (SAR), and/or (3) restricted stock. Annual grants may not exceed 1% of shares outstanding at the end of the preceding year; allowed shares not granted may be granted in future years. The Company uses APB Opinion No. 25 to account for stock-based compensation, accruing costs of restricted stock and any stock options deemed to be variable in nature over the vesting/performance periods and adjusting costs for changes in fair market value of Common Stock. Compensation cost charged against income for stock-based plans was $5,288,000 in 2002, $1,892,000 in 2001, and $7,914,000 in 2000. Outstanding awards were not significantly modified in the last three years.

STOCK OPTIONS – The Committee fixes the option price of each option granted at no less than fair market value (FMV) on the date of the grant and fixes the option term at no more than 10 years from such date. Each option granted to date under the Plan has had a term of 10 years, has been nonqualified, and has had an option price equal to or higher than FMV at date of grant. One-half of each grant may be exercised after two years and the remainder after three years. All disclosures that follow have been adjusted to reflect the two-for-one stock split effective December 30, 2002.

Changes in options outstanding, including shares issued under a prior plan, were as follows.

	Number of Shares	Average Exercise Price
Outstanding at December 31, 1999	2,508,738	$ 23.10
Granted at FMV	792,000	28.49
Exercised	(385,098)	21.82
Forfeited	(10,500)	24.88
Outstanding at December 31, 2000	2,905,140	24.73
Granted at FMV	1,036,000	30.83
Exercised	(522,400)	23.64
Outstanding at December 31, 2001	3,418,740	26.74
Granted at FMV	945,000	38.85
Exercised	(983,400)	23.44
Forfeited	(83,500)	31.30
Outstanding at December 31, 2002	3,296,840	31.08
Exercisable at December 31, 2000	1,181,640	$ 25.90
Exercisable at December 31, 2001	1,270,240	24.57
Exercisable at December 31, 2002	988,340	25.01

Additional information about stock options outstanding at December 31, 2002 is shown below.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices Per Option	No. of Options	Avg. Life in Years	Avg. Price	No. of Options	Avg. Price
$17.84 to $21.12	258,840	5.8	$ 18.04	258,840	$ 18.04
$24.88 to $28.48	1,010,500	6.2	27.43	617,000	26.76
$30.23 to $38.85	2,027,500	8.3	34.57	112,500	31.48
	3,296,840	7.5	31.08	988,340	25.01

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The pro forma net income calculations in Note A reflect the following fair values of stock options granted in 2002, 2001 and 2000; fair values of options have been estimated by using the Black-Scholes pricing model and the assumptions as shown.

	2002	2001	2000
Fair value per option at grant date	$ 9.59	$ 7.20	$ 7.50
Assumptions			
Dividend yield	2.56%	2.84%	2.91%
Expected volatility	26.80%	26.34%	26.06%
Risk-free interest rate	4.89%	4.93%	6.76%
Expected life	5 yrs.	5 yrs.	5 yrs.

SAR – SAR may be granted in conjunction with or independent of stock options; the Committee determines when SAR may be exercised and the price. No SAR have been granted.

RESTRICTED STOCK – Shares of restricted stock were granted under the Plan in certain years. Each grant will vest if the Company achieves specific financial objectives at the end of a five-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. During the performance period, a grantee receives dividends and may vote these shares, but shares are subject to transfer restrictions and are all or partially forfeited if a grantee terminates. The Company may reimburse a grantee up to 50% of the award value for personal income tax liability on stock awarded. On December 31, 2000, approximately 50% of eligible shares granted in 1996 were awarded, and the remaining shares were forfeited based on financial objectives achieved. At December 31, 2002, eligible shares granted in 1998 were awarded to the grantees based on financial objectives achieved. Changes in restricted stock outstanding were as follows.

(Number of shares)	2002	2001	2000
Balance at beginning of year	115,166	116,666	166,728
Awarded	(115,166)	—	(24,154)
Forfeited	—	(1,500)	(25,908)
Balance at end of year	—	115,166	116,666

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 if the Company achieves specific financial objectives. Compensation expense of $3,911,000, $11,816,000 and $6,970,000 was recorded in 2002, 2001 and 2000, respectively, for these plans.

EMPLOYEE STOCK PURCHASE PLAN (ESPP) – The Company has an ESPP under which 300,000 shares of the Company's Common Stock could be purchased by eligible U.S. and Canadian employees. Each quarter, an eligible employee may elect to withhold up to 10% of his or her salary to purchase shares of the Company's stock at a price equal to 90% of the fair value of the stock as of the first day of the quarter. The ESPP will terminate on the earlier of the date that employees have purchased all 300,000 shares or June 30, 2007. Employee stock purchases under the ESPP were 24,828 shares at an average price of $38.94 per share in 2002, 27,350 shares at $25.54 in 2001 and 40,974 shares at $18.78 in 2000. At December 31, 2002, 141,913 shares remained available for sale under the ESPP. Compensation costs related to the ESPP were immaterial.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 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, 2002 and 2001 and a statement of the funded status as of December 31, 2002 and 2001.

	Pension Benefits		Postretirement Benefits	
(Thousands of dollars)	**2002**	**2001**	**2002**	**2001**
Change in benefit obligation				
Obligation at January 1	$ 261,182	247,718	43,335	38,454
Service cost	6,721	5,757	1,287	935
Interest cost	18,098	17,370	3,280	3,009
Plan amendments	227	—	—	—
Participant contributions	69	71	539	551
Actuarial loss	21,160	8,811	10,306	4,311
Settlements	—	(1,660)	—	—
Exchange rate changes	4,274	(1,773)	—	—
Benefits paid	(15,093)	(15,112)	(5,079)	(3,925)
Obligation at December 31	296,638	261,182	53,668	43,335
Change in plan assets				
Fair value of plan assets at January 1	256,872	300,203	—	—
Actual return on plan assets	(12,247)	(25,379)	—	—
Employer contributions	1,626	1,089	4,540	3,374
Participant contributions	69	71	539	551
Settlements	(375)	(1,924)	—	—
Exchange rate changes	3,580	(2,076)	—	—
Benefits paid	(15,093)	(15,112)	(5,079)	(3,925)
Fair value of plan assets at December 31	234,432	256,872	—	—
Reconciliation of funded status				
Funded status at December 31	(62,206)	(4,310)	(53,668)	(43,335)
Unrecognized actuarial (gain) loss	87,259	35,809	20,178	10,505
Unrecognized transition asset	(6,649)	(9,091)	—	—
Unrecognized prior service cost	6,559	6,956	—	—
Net plan asset (liability) recognized	$ 24,963	29,364	(33,490)	(32,830)
Amounts recognized in the Consolidated Balance Sheets at December 31				
Prepaid benefit asset	$ 47,070	45,454	—	—
Accrued benefit liability	(26,660)	(17,310)	(33,490)	(32,830)
Intangible asset	2,472	1,220	—	—
Accumulated other comprehensive loss*	2,081	—	—	—
Net plan asset (liability) recognized	$ 24,963	29,364	(33,490)	(32,830)

* Before reduction for associated deferred taxes of $729.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, 2002, a minimum pension liability adjustment was required for certain of the Company's domestic plans. For these plans, accumulated benefit obligations exceeded the fair value of plan assets by $15,699,000, compared with a net liability recognized in the balance sheet of $12,001,000. After reductions for amounts charged to intangible assets of $2,081,000 and associated deferred income taxes of $729,000, a charge to accumulated other comprehensive loss of $1,352,000 was recorded.

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)	2002	2001	2002	2001	2002	2001
Funded qualified plans where PBO exceeds fair value of plan assets	$262,349	28,920	227,360	24,082	217,891	22,730
Unfunded nonqualified and directors' plans where PBO exceeds fair value of plan assets	23,882	14,581	14,582	10,541	—	—
Unfunded postretirement plans	53,668	43,335	33,490	32,830	—	—

The table that follows provides the components of net periodic benefit expense (credit) for each of the three years ended December 31, 2002.

	Pension Benefits			Postretirement Benefits		
(Thousands of dollars)	2002	2001	2000	2002	2001	2000
Service cost	$ 6,721	5,757	5,461	1,287	935	753
Interest cost	18,097	17,370	17,010	3,280	3,009	2,699
Expected return on plan assets	(19,791)	(24,123)	(24,412)	—	—	—
Amortization of prior service cost	778	782	791	—	—	—
Amortization of transitional asset	(2,559)	(2,552)	(2,585)	—	—	—
Recognized actuarial (gain) loss	1,242	(181)	(395)	633	400	234
	4,488	(2,947)	(4,130)	5,200	4,344	3,686
Settlement gain	—	(901)	(1,824)	—	—	—
Net periodic benefit expense (credit)	$ 4,488	(3,848)	(5,954)	5,200	4,344	3,686

Settlement gains in 2001 related to employee reductions from the sale of Canadian pipeline and trucking assets, while 2000 gains were due to voluntary conversion of certain Canadian employees' retirement coverage from the defined benefit pension plan to a defined contribution plan.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(Thousands of dollars)	Pension Benefits 2002	Pension Benefits 2001	Postretirement Benefits 2002	Postretirement Benefits 2001
Benefit obligation at December 31	$54,731	49,010	—	—
Fair value of plan assets at December 31	48,428	46,709	—	—
Net plan asset (liability) recognized	(1,464)	73	—	—
Net periodic benefit expense (credit)	1,077	(704)	—	—

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2002 and 2001.

	Pension Benefits 2002	Pension Benefits 2001	Postretirement Benefits 2002	Postretirement Benefits 2001
Discount rate	6.56%	7.00%	6.75%	7.25%
Expected return on plan assets	7.81%	8.30%	—	—
Rate of compensation increase	4.52%	4.59%	—	—

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

For purposes of measuring postretirement benefit obligations at December 31, 2002, the future annual rates of increase in the cost of health care were assumed to be 7.0% for 2003 decreasing 0.5% per year to an ultimate rate of 5.0% in 2007 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, 2002	$ 321	(304)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 2002	2,770	(2,654)

THRIFT PLANS – Most 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 12,417 shares in 2002, 16,136 shares in 2001 and 6,360 shares in 2000. Amounts charged to expense for these plans were $4,159,000 in 2002, $4,061,000 in 2001 and $3,699,000 in 2000.

Note K – Financial Instruments and Risk Management

DERIVATIVE INSTRUMENTS – Murphy utilizes derivative instruments on a limited basis to manage certain risks related to interest rates, commodity prices, 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.

- *Interest Rate Risks* – Murphy has variable-rate debt obligations that expose the Company to the effects of changes in interest rates. To partially reduce its exposure to interest rate risk, Murphy has interest rate swap agreements with notional amounts totaling $50,000,000 at December 31, 2002 to hedge fluctuations in cash flows of a similar amount of variable rate debt. Interest rate swaps with notional amounts totaling $50,000,000 matured during the second quarter of 2002. The remaining swaps mature in 2004. Under the interest rate swaps, the Company pays fixed rates averaging 6.17% over their composite lives and receives variable rates which averaged 1.64% at December 31, 2002. The variable rate received by the Company under each contract is repriced quarterly. The Company has a risk management control system to monitor interest rate cash flow risk attributable to the Company's outstanding and forecasted debt obligations as well as the offsetting interest rate swaps. The control system involves using analytical techniques, including cash flow sensitivity analysis, to estimate the impact of interest rate changes on future cash flows. The fair value of the effective portions of the interest rate swaps and changes thereto is deferred in Accumulated Other Comprehensive Loss (AOCL) and is subsequently reclassified into Interest Expense in the periods in which the hedged interest payments on the variable-rate debt affect earnings. For the years ended December 31, 2002 and 2001, the income effect from cash flow hedging ineffectiveness of interest rates was insignificant. The fair value of the interest rate swaps are estimated using projected Federal funds rates, Canadian overnight funding rates and LIBOR forward curve rates obtained from published indices and counterparties. The estimated fair value approximates the values based on quotes from each of the counterparties.
- *Natural Gas Fuel Price Risks* – The Company purchases natural gas as fuel at its Meraux, Louisiana refinery, and as such, is subject to commodity price risk related to the purchase price of this gas. Murphy has hedged the cash flow risk associated with the cost of a portion of the natural gas it will purchase in 2004 through 2006 by entering into natural gas swap contracts with a total notional volume of 9.2 million British Thermal Units (MMBTU). Under the natural gas swaps, the Company pays a fixed rate averaging $2.78 per MMBTU and receives a floating rate in each month of settlement based on the average NYMEX price for the final three trading days of the month. Murphy has a risk management control system to monitor natural gas price risk attributable both to forecasted natural gas requirements and to Murphy's natural gas swaps. The control system involves using analytical techniques, including various correlations of natural gas purchase prices to future prices, to estimate the impact of changes in natural gas fuel prices on Murphy's cash flows. The fair value of the effective portions of the natural gas swaps and changes thereto is deferred in AOCL and is subsequently reclassified into Crude Oil, Natural Gas and Product Purchases in the income statements in the periods in which the hedged natural gas fuel purchases affect earnings. For the years ended December 31, 2002 and 2001, the income effect from cash flow hedging ineffectiveness for these controls was insignificant.
- *Natural Gas Sales Price Risks* – The sales price of natural gas produced by the Company is subject to commodity price risk. Murphy has hedged the cash flow risk associated with the sales price for a portion of the natural gas it will produce in the United States and Canada during 2003 by entering into financial contracts known as natural gas swaps and collars. The swaps cover a combined notional volume averaging 24,200 MMBTU equivalents per day and require Murphy to pay the average relevant index (NYMEX or AECO "C") price for each month and receive an average price of $3.76 per MMBTU equivalent. The natural gas collars are for a combined notional volume averaging 26,700 MMBTU equivalents per day and based upon the relevant index prices provide Murphy with an average floor price of $3.24 per MMBTU and an average ceiling price of $4.64 per MMBTU. Murphy has a risk management control system to monitor natural gas price risk attributable both to forecasted natural gas sales prices and to Murphy's hedging instruments. The control system involves using analytical techniques, including various correlations of

natural gas sales prices to futures prices, to estimate the impact of changes in natural gas prices on Murphy's cash flows from the sale of natural gas.

The natural gas price risk pertaining to a portion of gas sales from properties Murphy acquired from Beau Canada in 2000 was limited by natural gas swap agreements that expired in October 2001 that were obtained in the acquisition. These agreements hedged fluctuations in cash flows resulting from such risk. Certain swaps required Murphy to pay a floating price and receive a fixed price and were partially offset by swaps on a lesser volume that required Murphy to pay a fixed price and receive a floating price. The fair value of these swaps was recorded as a net liability upon the acquisition of Beau Canada and was adjusted on January 1, 2001 upon transition to SFAS 133. Net payments by the Company were recorded as a reduction of the associated liability, with any differences recorded as an adjustment of natural gas revenue.

The fair values of the effective portions of the natural gas swaps and collars and changes thereto are deferred in AOCL and are subsequently reclassified into Sales and Other Operating Revenue in the income statement in the periods in which the hedged natural gas sales affect earnings. For the years ended December 31, 2002 and 2001, Murphy's earnings were not significantly affected by cash flow hedging ineffectiveness. During 2002, the Company received approximately $6,900,000 for settlement of natural gas swap and collar agreements in Canada that were entered into in early 2002 and matured before the end of the period.

The fair value of the natural gas fuel swaps and the natural gas sales swaps and collars are both based on the average fixed price of the instruments and the published NYMEX and AECO "C" index futures price or natural gas price quotes from counterparties.

- *Crude Oil Sales Price Risks* – The sales price of crude oil produced by the Company is subject to commodity price risk. Murphy has hedged the cash flow risk associated with the sales price for a portion of the crude oil it will produce in the United States and Canada during 2003 by entering into financial contracts known as crude oil swaps. A portion of the swaps cover a notional volume of 22,000 barrels per day of light oil and require Murphy to pay the average of the closing settlement price on the NYMEX for the Nearby Light Crude Futures Contract for each month and receive an average price of $25.30 per barrel. Additionally, there are heavy oil swaps with a notional volume of 10,000 barrels per day that require Murphy to pay the arithmetic average of the posted price at terminals at Kerrobert and Hardisty, Canada for each month and receive an average price of $16.74 per barrel. Murphy has a risk management control system to monitor crude oil price risk attributable both to forecasted crude oil sales prices and to Murphy's hedging instruments. The control system involves using analytical techniques, including various correlations of crude oil sales prices to futures prices, to estimate the impact of changes in crude oil prices on Murphy's cash flows from the sale of light and heavy crude oil.

  The fair values of the effective portions of the crude oil hedges and changes thereto are deferred in AOCL and are subsequently reclassified into Sales and Other Operating Revenues in the income statement in the periods in which the hedged crude oil sales affect earnings. In the fourth quarter of 2002, cash flow hedging ineffectiveness relating to the crude oil sales swaps reduced Murphy's after-tax earnings by $1,371,000.

  The fair value of the crude oil sales swaps are based on the average fixed price of the instruments and the published NYMEX index futures price or crude oil price quotes from counterparties.

- *Crude Oil Purchase Price Risks* – Each month, the Company purchases crude oil as the primary feedstock for its U.S. refineries. Prior to April 2000, the Company was a party to crude oil swap agreements that limited the exposure of its U.S. refineries to the risks of fluctuations in cash flows resulting from changes in the prices of crude oil purchases in 2001 and 2002. Under each swap, Murphy would have paid a fixed crude oil price and would have received a floating price during the agreement's contractual maturity period. In April 2000, the Company settled certain of the swaps and entered into offsetting contracts for the remaining swap agreements, locking in a total pretax gain of $7,735,000. The fair values of these settlement gains were recorded in AOCL as part of the transition adjustment at January 1, 2001 and were recognized as a reduction of costs of crude oil purchases in the period the forecasted transactions occurred. Pretax gains of $5,778,000 in 2002 and $1,957,000 in 2001 were reclassified from AOCL into earnings.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During 2003, the Company expects to reclassify approximately $16,135,000 in net after-tax losses from AOCL into earnings as the forecasted transactions covered by hedging instruments actually occur. All forecasted transactions currently being hedged are expected to occur by December 2006.

FAIR VALUE – The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2002 and 2001. 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, investments and noncurrent receivables, trade accounts payable and accrued expenses, all of which had fair values approximating carrying amounts. The fair value of current and long-term debt is estimated based on current rates offered the Company 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.

	2002		2001	
(Thousands of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets (liabilities):				
Interest rate swaps	$ (3,829)	(3,829)	(4,269)	(4,269)
Natural gas fuel swaps	12,398	12,398	4,309	4,309
Natural gas sales swaps and collars	(6,405)	(6,405)	842	842
Crude oil sales swaps	(19,871)	(19,871)	—	—
Crude oil purchase swaps	—	—	1,914	1,914
Current and long-term debt	(919,912)	(923,350)	(569,035)	(542,115)

The carrying amounts of interest rate swaps, crude oil swaps and natural gas swaps and collars in the preceding table are included in the Consolidated Balance Sheets in Deferred Charges and Other Assets or Other Accrued Liabilities. Current and long-term debt are included under Current Maturities of Long-Term Debt, Notes Payable and Nonrecourse Debt of a Subsidiary.

CREDIT RISKS – The Company's primary credit risks are associated with trade accounts receivable, cash equivalents and derivative instruments. Trade receivables arise mainly from sales of crude oil, natural gas and petroleum products to a large number of customers in the United States, Canada and the United Kingdom. The 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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2002. No difference existed between net income used in computing basic and diluted income per Common share for these years.

(Weighted-average shares outstanding)	2002	2001	2000
Basic method	91,450,836	90,442,944	90,063,330
Dilutive stock options	684,131	739,054	416,082
Diluted method	92,134,967	91,181,998	90,479,412

The computations of diluted earnings per share in the Consolidated Statements of Income did not consider outstanding options of 294,000 shares at year-end 2000 because the effects of these options would have improved the Company’s earnings per share. The average exercise price per share of the options not used was $31.49. There were no antidilutive options for the 2002 and 2001 years.

Note N – Other Financial Information

INVENTORIES – Inventories accounted for under the LIFO method totaled $95,825,000 and $90,464,000 at December 31, 2002 and 2001, respectively, and were $129,044,000 and $51,054,000 less than such inventories would have been valued using the FIFO method.

ABANDONMENT AND RECLAMATION COSTS – The cost of future abandonment and reclamation of proved oil and gas properties under current accounting practices has been estimated by the Company’s engineers to be approximately $334,000,000 at December 31, 2002. The estimated total expense to be recorded in future years related to these properties is approximately $173,000,000.

ACCUMULATED OTHER COMPREHENSIVE LOSS – At December 31, 2002 and 2001, the components of Accumulated Other Comprehensive Loss were as follows.

(Thousands of dollars)	2002	2001
Foreign currency translation loss	$ (56,984)	(87,862)
Cash flow hedge gains (losses), net	(8,454)	4,553
Minimum pension liability, net	(1,352)	—
Balance at end of year	$ (66,790)	(83,309)

At December 31, 2002, components of the net foreign currency translation loss of $56,984,000 were gains (losses) of $27,369,000 for pounds sterling, $(85,204,000) for Canadian dollars and $851,000 for other currencies. Comparability of net income was not significantly affected by exchange rate fluctuations in 2002, 2001 and 2000. Net gains from foreign currency transactions included in the Consolidated Statements of Income were $792,000 in 2002, $1,406,000 in 2001 and $252,000 in 2000.

CASH FLOW DISCLOSURES – In association with the Beau Canada acquisition, the Company assumed debt of $124,227,000, a nonmonetary transaction excluded from both financing and investing activities in the Consolidated Statement of Cash Flows for the year ended December 31, 2000. Cash income taxes paid were $28,531,000, $135,734,000 and $53,583,000 in 2002, 2001 and 2000, respectively. Interest paid, net of amounts capitalized, was $20,977,000, $12,945,000 and $15,185,000 in 2002, 2001 and 2000, respectively.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Noncash operating working capital (increased) decreased for each of the three years ended December 31, 2002 as follows.

(Thousands of dollars)	2002	2001	2000
Accounts receivable	$ (146,760)	207,594	(95,675)
Inventories	(28,196)	(8,393)	(12,197)
Prepaid expenses	1,100	(37,113)	5,794
Deferred income tax assets	662	6,139	(4,196)
Accounts payable and accrued liabilities	135,800	(176,213)	142,228
Current income tax liabilities	13,181	(19,965)	30,048
Net (increase) decrease in noncash operating working capital excluding acquisition of Beau Canada	$ (24,213)	(27,951)	66,002

Note O – Commitments

The Company leases land, gasoline stations and other facilities under operating leases. During the next five years, future minimum rental commitments under noncancellable operating leases decline gradually from $20,500,000 in 2003 to $18,935,000 in 2007. Rental expense for noncancellable operating leases, including contingent payments when applicable, was $32,087,000 in 2002, $23,859,000 in 2001 and $17,425,000 in 2000. Additionally, 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 2018. The contract requires the payment of a base facility charge for use of the facility. Future required minimum annual payments for base facility charges are $1,323,000 in 2003, $5,292,000 for each of the years 2004 through 2007, and $56,889,000 in later years. 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 $1,489,000 in 2003 through 2007 and $19,355,000 in later years. 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 $1,435,000 in 2002, $1,805,000 in 2001, and $507,000 in 2000. Commitments for capital expenditures were approximately $623,000,000 at December 31, 2002, including $82,100,000 related to expansion projects at the Meraux refinery; $126,300,000 for costs to develop deepwater Gulf of Mexico fields, including Medusa, Front Runner, and Habanero; $110,200,000 for continued expansion of synthetic oil operations in Canada; and $121,800,000 for future combined work commitments in Malaysia and offshore Nova Scotia. The expansion projects at the Meraux refinery include construction of a hydrocracker unit that will allow the refinery to produce low-sulfur products, an expansion of crude oil processing capacity from 100,000 barrel per day to 125,000 barrels per day and construction of an additional sulfur recovery complex.

Note P – 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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 11 terminals, and approximately 80 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 17 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. If regulatory authorities require more costly alternatives than the proposed processes, future expenditures could exceed the accrued liability by up to an estimated $3,000,000.

The Company has received notices from the U.S. Environmental Protection Agency (EPA) that it is currently considered 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. At one site the Company has agreed to pay $8,100 to obtain release from further obligations. The Company's insurance carrier has agreed to reimburse the $8,100. Based on currently available information, the Company believes that it is a *de minimus* party as to ultimate responsibility at the other Superfund site. 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 one remaining site or other Superfund sites. The Company does not believe that the ultimate costs to clean-up the two Superfund sites will have a material adverse effect on its net income or cash flows 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 future earnings or cash flows.

In December 2000, two of the Company's Canadian subsidiaries, Murphy Oil Company Ltd. (MOCL) and Murphy Canada Exploration Company (MCEC) as plaintiffs filed an action in the Court of Queen's Bench of Alberta seeking a constructive trust over oil and gas leasehold rights to Crown lands in British Columbia. The suit alleges that the defendants, The Predator Corporation Ltd. and Predator Energies Partnership (collectively Predator) and Ricks Nova Scotia Co. (Ricks), acquired the lands after first inappropriately obtaining confidential and proprietary data belonging to the Company and its partner. In January 2001, Ricks, representing an undivided 75% interest in the lands in question, settled its portion of the litigation by conveying its interest to the Company and its partner at cost. In 2001, Predator, representing the remaining undivided 25% of the lands in question, filed a counterclaim, as subsequently amended, against MOCL and MCEC and MOCL's President individually seeking compensatory damages of C$4.61 billion. The Company believes that the counterclaim is without merit and that the amount of damages sought is frivolous. While the litigation is in its preliminary stages and no assurance can be given about the outcome, the Company does not believe that the ultimate resolution of this suit will have a material adverse effect on its financial condition.

Murphy and its subsidiaries are engaged in a number of other legal proceedings, all of which Murphy considers routine and incidental to its business and none of which is expected to have a material adverse effect on the Company's financial condition. 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 earnings or financial condition in a future period.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2002, the Company had contingent liabilities of $12,706,000 under a financial guarantee described in the following paragraph and $27,738,000 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 are remote.

An investee Limited Liability Company accounted for at cost has issued $397,070,000 in bonds. The bonds mature in varying amounts between 2003 and 2021. Under the Limited Liability Company Agreement and the First Stage Throughput and Deficiency (T&D) Agreement, the Company is obligated in accordance with its 3.2% ownership to ship crude oil in quantities sufficient for the investee to pay certain of its expenses and obligations, including the investee's long-term debt secured by the T&D agreement, 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, 2002, 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 would recognize any such losses under the guarantees should losses become probable.

Note Q – Common Stock Issued and Outstanding

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2002 is shown below.

(Number of shares outstanding)	2002	2001	2000
At beginning of year	45,331,080	45,045,545	44,997,995
Stock options exercised	491,700	261,200	43,678
Employee stock purchase plans	28,647	24,896	16,855
Restricted stock forfeitures	—	(750)	(12,954)
Two-for-one stock split	45,838,065	—	—
All other	(38)	189	(29)
At end of year	91,689,454	45,331,080	45,045,545

Note R – Subsequent Event (unaudited)

In early 2003, the Company signed a letter of intent to sell its interests in the Ninian and Columba fields in the U.K. for total proceeds of approximately $36,000,000. The transaction should close in the second quarter.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note S – Business Segments

Murphy's reportable segments are organized into two major types of business activities, each subdivided into geographic areas of operations. The Company's exploration and production activity is subdivided into segments for the United States, Canada, the United Kingdom, Ecuador, Malaysia and all other countries; each of these segments derives revenues primarily from the sale of crude oil and natural gas. The refining and marketing segments in North America and the United Kingdom derive revenues mainly from the sale of petroleum products. The company sold its Canadian pipeline and trucking assets in May 2001. During 2002, the Company changed its reportable segments to combine U.S. and Canadian refining and marketing operations into one North American segment. Operations for crude oil trading and transportation activities in Canada prior to sale of this operation in 2001 have been included in the North American segment in past years. Beginning in 2002, the Company began selling gasoline in Canada at retail stations built in Wal-Mart parking lots. This business is considered by the Company to be an integrated operation similar to its U.S. business, and therefore, considers it appropriate to combine the Canadian business with its U.S. operation and report as 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. Excise taxes on petroleum products of $1,147,922,000, $1,005,018,000 and $1,052,760,000 for the years 2002, 2001 and 2000, respectively, were excluded from revenues and costs and expenses. For geographic purposes, revenues are attributed to the country in which the sale occurs. The Company had no single customer from which it derived more than 10% of its revenues. Corporate and other activities, including interest income, miscellaneous gains and losses, interest expense and unallocated overhead, are shown in the tables to reconcile the business segments to consolidated totals. As used in the table on page F-30, Certain Long-Lived Assets at December 31 exclude investments, noncurrent receivables, deferred tax assets and intangible assets.

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Segment Information (Millions of dollars)	Exploration and Production						
	U.S.	Canada	U.K.	Ecuador	Malaysia	Other	Total
Year ended December 31, 2002							
Segment income (loss) from continuing operations	$ (11.8)	157.0	49.6	12.0	(43.0)	(2.8)	161.0
Revenues from external customers	155.0	527.1	170.6	30.7	—	2.3	885.7
Intersegment revenues	3.3	83.4	—	—	—	—	86.7
Interest income	—	—	—	—	—	—	—
Interest expense, net of capitalization	—	—	—	—	—	—	—
Income tax expense (benefit)	(20.9)	79.8	42.3	—	—	(.9)	100.3
Significant noncash charges (credits)							
Depreciation, depletion, amortization	34.1	170.9	35.7	5.3	.9	.3	247.2
Impairment of properties	31.6	—	—	—	—	—	31.6
Provisions for major repairs	—	5.5	—	—	—	—	5.5
Amortization of undeveloped leases	10.5	14.1	—	—	—	—	24.6
Deferred and noncurrent income taxes	(18.7)	7.6	6.1	—	—	.6	(4.4)
Additions to property, plant, equipment	169.2	191.9	36.0	14.9	85.0	—	497.0
Total assets at year-end	661.8	1,269.9	243.7	82.0	122.1	7.9	2,387.4
Year ended December 31, 2001							
Segment income (loss) from continuing operations	$ 55.3	85.5	78.6	11.5	(36.1)	(7.3)	187.5
Revenues from external customers	223.1	366.5	194.2	33.4	—	2.2	819.4
Intersegment revenues	3.8	81.2	—	—	—	—	85.0
Interest income	—	—	—	—	—	—	—
Interest expense, net of capitalization	—	—	—	—	—	—	—
Income tax expense (benefit)	29.4	51.6	44.3	—	—	(1.0)	124.3
Significant noncash charges (credits)							
Depreciation, depletion, amortization	37.7	99.0	37.2	6.4	.5	.3	181.1
Amortization of goodwill	—	3.1	—	—	—	—	3.1
Impairment of properties	8.9	—	—	—	—	—	8.9
Provisions for major repairs	—	3.3	—	—	—	—	3.3
Amortization of undeveloped leases	9.5	13.6	—	—	—	—	23.1
Deferred and noncurrent income taxes	27.0	53.2	(3.3)	—	—	.5	77.4
Additions to property, plant, equipment	222.8	287.0	17.9	9.0	9.6	—	546.3
Total assets at year-end	582.1	1,255.8	213.5	69.9	22.2	7.5	2,151.0
Year ended December 31, 2000							
Segment income (loss) from continuing operations	$ 43.3	108.1	90.2	21.1	(10.7)	(6.3)	245.7
Revenues from external customers	255.0	278.6	211.5	51.5	—	2.2	798.8
Intersegment revenues	4.8	106.3	11.6	—	—	—	122.7
Interest income	—	—	—	—	—	—	—
Interest expense, net of capitalization	—	—	—	—	—	—	—
Income tax expense (benefit)	23.3	66.3	56.2	—	—	—	145.8
Significant noncash charges (credits)							
Depreciation, depletion, amortization	47.6	70.0	41.7	6.8	.4	.1	166.6
Impairment of properties	21.0	6.9	—	—	—	—	27.9
Provisions for major repairs	—	3.3	—	—	—	—	3.3
Amortization of undeveloped leases	7.7	6.4	—	—	—	—	14.1
Deferred and noncurrent income taxes	(5.1)	55.6	(1.5)	—	—	1.0	50.0
Additions to property, plant, equipment	69.9	425.5	24.6	12.3	8.1	.8	541.2
Total assets at year-end	413.6	1,131.1	261.7	79.8	9.3	7.1	1,902.6

Geographic Information (Millions of dollars)	Certain Long-Lived Assets at December 31						
	U.S.	Canada	U.K.	Ecuador	Malaysia	Other	Total
2002	$1,302.2	1,116.8	295.0	70.9	101.8	6.3	2,893.0
2001	1,058.8	1,117.5	272.3	61.6	17.7	5.7	2,533.6
2000	764.8	1,063.2	297.1	59.0	8.7	5.9	2,198.7

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Segment Information (Continued) (Millions of dollars)	Refining and Marketing North America	Refining and Marketing U.K.	Refining and Marketing Total	Corp. & Other	Consolidated
Year ended December 31, 2002					
Segment income (loss) from continuing operations	$ (39.2)	(.7)	(39.9)	(23.6)	97.5
Revenues from external customers	2,688.7	404.5	3,093.2	5.4	3,984.3
Intersegment revenues	—	—	—	—	86.7
Interest income	—	—	—	5.4	5.4
Interest expense, net of capitalization	—	—	—	27.0	27.0
Income tax expense (benefit)	(20.7)	1.5	(19.2)	(26.9)	54.2
Significant noncash charges (credits)					
Depreciation, depletion, amortization	43.4	6.7	50.1	2.7	300.0
Impairment of properties	—	—	—	—	31.6
Provisions for major repairs	16.7	2.7	19.4	.1	25.0
Amortization of undeveloped leases	—	—	—	—	24.6
Deferred and noncurrent income taxes	13.4	(.5)	12.9	(2.6)	5.9
Additions to property, plant, equipment	230.4	4.3	234.7	1.1	732.8
Total assets at year-end	996.6	211.6	1,208.2	290.2	3,885.8
Year ended December 31, 2001					
Segment income (loss) from continuing operations	$ 139.6	14.1	153.7	(12.8)	328.4
Revenues from external customers	2,674.0	360.9	3,034.9	11.7	3,866.0
Intersegment revenues	.2	—	—	—	85.2
Interest income	—	—	—	11.6	11.6
Interest expense, net of capitalization	—	—	—	19.0	19.0
Income tax expense (benefit)	71.2	5.0	76.2	(26.8)	173.7
Significant noncash charges (credits)					
Depreciation, depletion, amortization	36.9	6.1	43.0	2.5	226.6
Amortization of goodwill	—	—	—	—	3.1
Impairment of properties	1.6	—	1.6	—	10.5
Provisions for major repairs	15.7	1.9	17.6	.1	21.0
Amortization of undeveloped leases	—	—	—	—	23.1
Deferred and noncurrent income taxes	2.5	2.5	5.0	(2.3)	80.1
Additions to property, plant, equipment	162.8	12.4	175.2	5.8	727.3
Total assets at year-end	734.4	184.4	918.8	189.3	3,259.1
Year ended December 31, 2000					
Segment income (loss) from continuing operations	$ 31.5	23.0	54.5	(1.7)	298.5
Revenues from external customers	2,425.2	409.3	2,834.5	24.9	3,658.2
Intersegment revenues	1.6	—	1.6	—	124.3
Interest income	—	—	—	21.7	21.7
Interest expense, net of capitalization	—	—	—	16.3	16.3
Income tax expense (benefit)	20.1	11.3	31.4	(21.2)	156.0
Significant noncash charges (credits)					
Depreciation, depletion, amortization	35.3	5.6	40.9	3.4	210.9
Impairment of properties	—	—	—	—	27.9
Provisions for major repairs	17.6	1.8	19.4	.1	22.8
Amortization of undeveloped leases	—	—	—	—	14.1
Deferred and noncurrent income taxes	5.2	1.2	6.4	7.0	63.4
Additions to property, plant, equipment	141.4	12.4	153.8	11.4	706.4
Total assets at year-end	796.0	222.6	1,018.6	213.2	3,134.4

Geographic Information (Millions of dollars)	Revenues from External Customers for the Year U.S.	U.K.	Canada	Ecuador	Other	Total
2002	$2,843.4	578.0	529.9	30.7	2.3	3,984.3
2001	2,788.4	562.7	479.3	33.4	2.2	3,866.0
2000	2,668.7	625.9	309.9	51.5	2.2	3,658.2

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

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

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

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

Production quantities shown are net volumes withdrawn from reservoirs. These may differ from sales quantities due to inventory changes, and especially in the case of natural gas, volumes consumed for fuel and/or shrinkage from extraction of natural gas liquids.

Oil reserves in Ecuador are derived from a participation agreement covering Block 16 in the Amazon region. Oil reserves associated with the participation agreement in Ecuador totaled 32.9 million barrels at December 31, 2002. Oil reserves in Malaysia are associated with a production sharing contract for Block SK 309. Malaysia reserves include oil to be received for both cost recovery and profit provisions under the contract. Oil reserves associated with the production sharing contract in Malaysia totaled 15.3 million barrels at December 31, 2002.

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 reserve table at Schedule 2, are attributable to Murphy’s 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. Results of oil and gas producing activities include certain nonrecurring items that are reviewed in Management’s Discussion and Analysis of Financial Condition and Results of Operations on pages 10 and 11 of this Form 10-K report, and should be considered in conjunction with the Company’s overall performance.

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

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. Average year-end 2002 crude oil prices used for this calculation were $30.07 per barrel for the United States, $25.27 for Canadian light, $18.91 for Canadian heavy, $30.18 for Canadian offshore, $30.03 for the United Kingdom, $20.98 for Ecuador and $30.56 for Malaysia. Average year-end 2002 natural gas prices used were $4.69 per MCF for the United States, $3.71 for Canada and $3.16 for the United Kingdom.

Schedule 5 also presents the principal reasons for change in the standardized measure of discounted future net cash flows for each of the three years ended December 31, 2002.

Schedule 1 – Estimated Net Proved Oil Reserves

	Crude Oil, Condensate and Natural Gas Liquids					
(Millions of barrels)	**United States***	**Canada**	**United Kingdom**	**Ecuador**	**Malaysia**	**Total**
Proved						
December 31, 1999	34.1	53.7	56.9	37.0	—	181.7
Revisions of previous estimates	(1.7)	4.5	1.8	3.6	—	8.2
Purchases	—	11.7	—	—	—	11.7
Extensions and discoveries	15.3	4.0	—	2.6	—	21.9
Production	(2.4)	(8.4)	(7.7)	(2.3)	—	(20.8)
Sales	—	(1.6)	—	—	—	(1.6)
December 31, 2000	45.3	63.9	51.0	40.9	—	201.1
Revisions of previous estimates	(.8)	2.8	.5	(.3)	—	2.2
Improved recovery	—	1.5	—	—	—	1.5
Purchases	—	.2	—	—	—	.2
Extensions and discoveries	46.2	3.3	—	—	15.0	64.5
Production	(2.1)	(9.4)	(7.4)	(1.9)	—	(20.8)
Sales	—	(1.8)	—	—	—	(1.8)
December 31, 2001	88.6	60.5	44.1	38.7	15.0	246.9
Revisions of previous estimates	(6.5)	6.6	3.7	(4.1)	.3	—
Extensions and discoveries	3.8	8.4	2.0	—	—	14.2
Production	(1.9)	(13.5)	(6.7)	(1.7)	—	(23.8)
Sales	(3.4)	(2.3)	—	—	—	(5.7)
December 31, 2002	80.6	59.7	43.1	32.9	15.3	231.6
Proved Developed						
December 31, 1999	11.7	26.6	34.1	21.2	—	93.6
December 31, 2000	10.3	34.3	36.3	20.1	—	101.0
December 31, 2001	8.8	37.9	33.3	21.3	—	101.3
December 31, 2002	5.2	47.1	36.2	19.0	—	107.5

* Includes net proved oil reserves related to discontinued operation of 2.0 million barrels at December 31, 2001 and 3.0 million barrels at December 31, 2000.

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

Schedule 2 – Estimated Net Proved Natural Gas Reserves

(Billions of cubic feet)	United States*	Canada	United Kingdom	Total
Proved				
December 31, 1999	427.3	125.8	38.5	591.6
Revisions of previous estimates	(41.9)	(5.0)	.3	(46.6)
Purchases	5.4	163.3	—	168.7
Extensions and discoveries	31.2	40.1	—	71.3
Production	(53.0)	(27.0)	(4.0)	(84.0)
Sales	—	(3.6)	—	(3.6)
December 31, 2000	369.0	293.6	34.8	697.4
Revisions of previous estimates	(20.2)	(2.1)	4.9	(17.4)
Improved recovery	—	.9	—	.9
Purchases	—	30.7	—	30.7
Extensions and discoveries	89.0	44.7	—	133.7
Production	(42.1)	(56.6)	(4.8)	(103.5)
Sales	—	(1.7)	—	(1.7)
December 31, 2001	395.7	309.5	34.9	740.1
Revisions of previous estimates	(84.2)	(7.5)	(1.5)	(93.2)
Purchases	—	.4	—	.4
Extensions and discoveries	3.8	12.7	—	16.5
Production	(33.6)	(72.1)	(2.6)	(108.3)
Sales	(13.2)	(17.1)	—	(30.3)
December 31, 2002	268.5	225.9	30.8	525.2
Proved Developed				
December 31, 1999	284.8	111.3	32.9	429.0
December 31, 2000	233.8	255.2	32.3	521.3
December 31, 2001	189.6	277.5	34.1	501.2
December 31, 2002	139.7	205.6	30.1	375.4

* Includes net proved natural gas reserves related to discontinued operations of 8.1 billion cubic feet at December 31, 2001 and 11.7 billion at December 31, 2000.

Information on Proved Reserves for Canadian Synthetic Oil Operation Not Included in Above 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, does not permit these associated proved reserves to be included as a part of conventional oil and natural gas reserves. These reserves are also not included in the Company's schedule of Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, which can be found on page F-38.

Synthetic Oil Proved Reserves (Millions of barrels)	
At December 31, 1999	120.5
At December 31, 2000	125.0
At December 31, 2001	131.0
At December 31, 2002	136.2

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

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

(Millions of dollars)	United States[1]	Canada[2]	United Kingdom	Ecuador	Malaysia	Other	Total
Year Ended December 31, 2002							
Property acquisition costs							
Unproved	$ 8.4	10.1	—	—	—	—	18.5
Proved	—	.6	—	—	—	—	.6
Total acquisition costs	8.4	10.7	—	—	—	—	19.1
Exploration costs	56.7	68.8	3.8	—	102.3	.2	231.8
Development costs	156.7	87.0	36.0	14.9	24.8	—	319.4
Total capital expenditures	221.8	166.5	39.8	14.9	127.1	.2	570.3
Charged to expense							
Dry hole expense	39.8	20.3	3.1	—	37.9	.1	101.2
Geophysical and other costs	12.8	15.8	.7	—	4.2	.1	33.6
Total charged to expense	52.6	36.1	3.8	—	42.1	.2	134.8
Expenditures capitalized	$169.2	130.4	36.0	14.9	85.0	—	435.5
Year Ended December 31, 2001							
Property acquisition costs							
Unproved	$ 40.1	25.1	—	—	—	—	65.2
Proved	.3	21.3	—	—	—	—	21.6
Total acquisition costs	40.4	46.4	—	—	—	—	86.8
Exploration costs	86.5	105.9	.9	—	44.3	4.6	242.2
Development costs	128.7	167.4	17.9	9.0	.9	—	323.9
Total capital expenditures	255.6	319.7	18.8	9.0	45.2	4.6	652.9
Charged to expense							
Dry hole expense	23.7	47.0	.1	—	8.4	3.6	82.8
Geophysical and other costs	9.1	12.9	.8	—	27.2	1.0	51.0
Total charged to expense	32.8	59.9	.9	—	35.6	4.6	133.8
Expenditures capitalized	$222.8	259.8	17.9	9.0	9.6	—	519.1
Year Ended December 31, 2000							
Property acquisition costs							
Unproved	$ 19.2	25.1	—	—	—	—	44.3
Proved	1.5	2.9	—	—	—	—	4.4
Total	20.7	28.0	—	—	—	—	48.7
Exploration costs	96.2	32.1	5.2	.1	18.4	4.7	156.7
Development costs	20.3	113.8	22.5	12.2	—	—	168.8
Total capital expenditures	137.2	173.9	27.7	12.3	18.4	4.7	374.2
Beau Canada property acquisition							
Unproved	—	18.2	—	—	—	—	18.2
Proved	—	241.8	—	—	—	—	241.8
Total	—	260.0	—	—	—	—	260.0
Charged to expense							
Dry hole expense	56.7	5.7	1.7	—	1.3	.6	66.0
Geophysical and other costs	10.6	21.2	1.4	—	9.0	3.3	45.5
Total charged to expense	67.3	26.9	3.1	—	10.3	3.9	111.5
Expenditures capitalized	$ 69.9	407.0	24.6	12.3	8.1	.8	522.7

1 Excludes $.5 million in 2002 and $3.4 million in 2001 related to discontinued operations. No costs were incurred in 2000.

2 Excludes costs incurred for the Company's 5% interest in Synthetic Oil operations in Canada. Total costs incurred were $61.5 million in 2002, $27.2 million in 2001 and $18.5 million in 2000.

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

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, 2002									
Revenues									
Crude oil and natural gas liquids									
Transfers to consolidated operations	$ —	51.7	—	—	—	—	51.7	31.7	83.4
Sales to unaffiliated enterprises	30.0	253.1	163.0	30.7	—	—	476.8	74.6	551.4
Natural gas									
Transfers to consolidated operations	3.3	—	—	—	—	—	3.3	—	3.3
Sales to unaffiliated enterprises	108.0	197.6	7.0	—	—	—	312.6	—	312.6
Total oil and gas revenues	141.3	502.4	170.0	30.7	—	—	844.4	106.3	950.7
Other operating revenues	17.0	1.8	.6	—	—	2.3	21.7	—	21.7
Total revenues	158.3	504.2	170.6	30.7	—	2.3	866.1	106.3	972.4
Costs and expenses									
Production expenses	43.7	88.5	35.9	12.8	—	—	180.9	48.7	229.6
Cost to repair storm damages	5.0	—	—	—	—	—	5.0	—	5.0
Exploration costs charged to expense	52.6	36.1	3.8	—	42.1	.2	134.8	—	134.8
Undeveloped lease amortization	10.5	14.1	—	—	—	—	24.6	—	24.6
Depreciation, depletion and amortization	34.1	162.1	35.7	5.3	.9	.3	238.4	8.8	247.2
Impairment of properties	31.6	—	—	—	—	—	31.6	—	31.6
Selling and general expenses	13.5	15.1	3.3	.6	—	5.5	38.0	.3	38.3
Total costs and expenses	191.0	315.9	78.7	18.7	43.0	6.0	653.3	57.8	711.1
	(32.7)	188.3	91.9	12.0	(43.0)	(3.7)	212.8	48.5	261.3
Income tax expense (benefit)	(20.9)	64.2	42.3	—	—	(.9)	84.7	15.6	100.3
Results of operations*	$ (11.8)	124.1	49.6	12.0	(43.0)	(2.8)	128.1	32.9	161.0
Year Ended December 31, 2001									
Revenues									
Crude oil and natural gas liquids									
Transfers to consolidated operations	$ —	50.6	—	—	—	—	50.6	30.6	81.2
Sales to unaffiliated enterprises	38.5	116.6	181.5	33.4	—	—	370.0	65.2	435.2
Natural gas									
Transfers to consolidated companies	3.8	—	—	—	—	—	3.8	—	3.8
Sales to unaffiliated enterprises	189.0	182.6	12.1	—	—	—	383.7	—	383.7
Total oil and gas revenues	231.3	349.8	193.6	33.4	—	—	808.1	95.8	903.9
Other operating revenues	(4.4)	2.1	.6	—	—	2.2	.5	—	.5
Total revenues	226.9	351.9	194.2	33.4	—	2.2	808.6	95.8	904.4
Costs and expenses									
Production expenses	41.4	72.0	30.8	14.9	—	—	159.1	51.9	211.0
Exploration costs charged to expense	32.8	59.9	.9	—	35.6	4.6	133.8	—	133.8
Undeveloped lease amortization	9.5	13.6	—	—	—	—	23.1	—	23.1
Depreciation, depletion and amortization	37.7	90.7	37.2	6.4	.5	.3	172.8	8.3	181.1
Amortization of goodwill	—	3.1	—	—	—	—	3.1	—	3.1
Impairment of properties	8.9	—	—	—	—	—	8.9	—	8.9
Selling and general expenses	11.9	11.0	2.4	.6	—	5.6	31.5	.1	31.6
Total costs and expenses	142.2	250.3	71.3	21.9	36.1	10.5	532.3	60.3	592.6
	84.7	101.6	122.9	11.5	(36.1)	(8.3)	276.3	35.5	311.8
Income tax expense (benefit)	29.4	39.1	44.3	—	—	(1.0)	111.8	12.5	124.3
Results of operations*	$ 55.3	62.5	78.6	11.5	(36.1)	(7.3)	164.5	23.0	187.5

* Excludes discontinued operations, corporate overhead and interest in 2002 and 2001. Income from discontinued operations was $14.0 million in 2002 and $2.5 million in 2001.

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

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

(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Malaysia	Other	Subtotal	Synthetic Oil – Canada	Total
Year Ended December 31, 2002									
Revenues									
Crude oil and natural gas liquids									
Transfers to consolidated operations	$ —	68.4	11.6	—	—	—	80.0	37.9	117.9
Sales to unaffiliated enterprises	53.2	125.5	203.0	52.2	—	—	433.9	53.6	487.5
Natural gas									
Transfers to consolidated operations	4.8	—	—	—	—	—	4.8	—	4.8
Sales to unaffiliated enterprises	206.6	99.0	7.8	—	—	—	313.4	—	313.4
Total oil and gas revenues	264.6	292.9	222.4	52.2	—	—	832.1	91.5	923.6
Other operating revenues	(4.8)	.5	.7	(.7)	—	2.2	(2.1)	—	(2.1)
Total revenues	259.8	293.4	223.1	51.5	—	2.2	830.0	91.5	921.5
Costs and expenses									
Production expenses	36.1	55.0	29.1	15.5	—	—	135.7	40.4	176.1
Exploration costs charged to expense	67.3	26.9	3.1	—	10.3	3.9	111.5	—	111.5
Undeveloped lease amortization	7.7	6.4	—	—	—	—	14.1	—	14.1
Depreciation, depletion and amortization	47.6	62.5	41.7	6.8	.4	.1	159.1	7.5	166.6
Impairment of properties	21.0	6.9	—	—	—	—	27.9	—	27.9
Selling and general expenses	13.5	4.8	2.8	.3	—	4.5	25.9	.1	26.0
Loss on transportation and other disputed contractual items	—	—	—	7.8	—	—	7.8	—	7.8
Total costs and expenses	193.2	162.5	76.7	30.4	10.7	8.5	482.0	48.0	530.0
	66.6	130.9	146.4	21.1	(10.7)	(6.3)	348.0	43.5	391.5
Income tax expense	23.3	49.2	56.2	—	—	—	128.7	17.1	145.8
Results of operations*	$ 43.3	81.7	90.2	21.1	(10.7)	(6.3)	219.3	26.4	245.7

* Excludes discontinued operations, corporate overhead and interest and the cumulative effect of an accounting change. Income from discontinued operations was $7.0 million in 2000.

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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[1]	Canada[2]	United Kingdom	Ecuador	Malaysia	Total
December 31, 2002						
Future cash inflows	$3,657.1	2,344.2	1,374.9	690.3	468.5	8,535.0
Future development costs	(332.0)	(57.0)	(55.2)	(64.5)	(83.6)	(592.3)
Future production and abandonment costs	(579.0)	(487.2)	(421.1)	(250.4)	(149.5)	(1,887.2)
Future income taxes	(905.7)	(579.7)	(376.8)	(116.7)	(84.6)	(2,063.5)
Future net cash flows	1,840.4	1,220.3	521.8	258.7	150.8	3,992.0
10% annual discount for estimated timing of cash flows	(633.6)	(291.3)	(160.0)	(88.2)	(38.5)	(1,211.6)
Standardized measure of discounted future net cash flows	$1,206.8	929.0	361.8	170.5	112.3	2,780.4
December 31, 2001						
Future cash inflows	$2,468.1	1,699.2	910.2	463.1	299.8	5,840.4
Future development costs	(490.1)	(98.5)	(61.1)	(63.2)	(70.9)	(783.8)
Future production and abandonment costs	(740.8)	(515.3)	(401.0)	(247.2)	(79.3)	(1,983.6)
Future income taxes	(365.3)	(287.7)	(139.7)	(37.8)	(61.0)	(891.5)
Future net cash flows	871.9	797.7	308.4	114.9	88.6	2,181.5
10% annual discount for estimated timing of cash flows	(372.8)	(211.5)	(94.0)	(45.3)	(31.5)	(755.1)
Standardized measure of discounted future net cash flows	$ 499.1	586.2	214.4	69.6	57.1	1,426.4
December 31, 2000						
Future cash inflows	$3,479.9	2,860.4	1,209.4	725.5	—	8,275.2
Future development costs	(321.8)	(97.3)	(55.0)	(72.2)	—	(546.3)
Future production and abandonment costs	(479.2)	(615.5)	(378.8)	(320.4)	—	(1,793.9)
Future income taxes	(935.6)	(673.4)	(294.8)	(95.6)	—	(1,999.4)
Future net cash flows	1,743.3	1,474.2	480.8	237.3	—	3,935.6
10% annual discount for estimated timing of cash flows	(620.4)	(456.1)	(153.3)	(102.0)	—	(1,331.8)
Standardized measure of discounted future net cash flows	$1,122.9	1,018.1	327.5	135.3	—	2,603.8

1 Includes discounted future net cash flows from discontinued operations of $1.9 million and $47.8 million at December 31, 2001 and 2000, respectively.

2 Excludes discounted future net cash flows from synthetic oil of $411 million at December 31, 2002, $188 million at December 31, 2001 and $441.5 million at December 31, 2000.

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

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

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

(Millions of dollars)	2002	2001	2000
Net changes in prices, production costs and development costs	$ 2,480.2	(2,636.9)	946.8
Sales and transfers of oil and gas produced, net of production costs	(672.9)	(655.4)	(709.9)
Net change due to extensions and discoveries	238.8	691.6	544.4
Net change due to purchases and sales of proved reserves	(150.9)	19.3	519.2
Development costs incurred	304.3	308.7	156.6
Accretion of discount	202.5	390.6	229.3
Revisions of previous quantity estimates	(223.2)	1.4	(73.7)
Net change in income taxes	(824.8)	703.3	(659.9)
Net increase (decrease)	1,354.0	(1,177.4)	952.8
Standardized measure at January 1	1,426.4	2,603.8	1,651.0
Standardized measure at December 31	$ 2,780.4	1,426.4	2,603.8

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, 2002									
Unproved oil and gas properties	$ 129.1	98.1	.2	—	57.1	3.5	288.0	—	288.0
Proved oil and gas properties	1,487.5	1,443.0	915.9	242.8	42.7	—	4,131.9	267.9	4,399.8
Gross capitalized costs	1,616.6	1,541.1	916.1	242.8	99.8	3.5	4,419.9	267.9	4,687.8
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	(31.2)	(45.8)	(.1)	—	—	(3.5)	(80.6)	—	(80.6)
Proved oil and gas properties[1]	(1,033.1)	(601.9)	(714.7)	(171.9)	—	—	(2,521.6)	(51.1)	(2,572.7)
Net capitalized costs	$ 552.3	893.4	201.3	70.9	99.8	—	1,817.7	216.8	2,034.5
December 31, 2001									
Unproved oil and gas properties	$ 128.6	130.6	.3	—	.4	3.5	263.4	—	263.4
Proved oil and gas properties	1,673.8	1,326.7	794.8	227.9	15.1	—	4,038.3	204.0	4,242.3
Gross capitalized costs	1,802.4	1,457.3	795.1	227.9	15.5	3.5	4,301.7	204.0	4,505.7
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	(23.0)	(33.8)	(.2)	—	—	(3.5)	(60.5)	—	(60.5)
Proved oil and gas properties[1]	(1,289.7)	(469.3)	(612.6)	(166.3)	—	—	(2,537.9)	(42.3)	(2,580.2)
Net capitalized costs[2]	$ 489.7	954.2	182.3	61.6	15.5	—	1,703.3	161.7	1,865.0

[1] Does not include reserve for dismantlement costs of $160.5 million in 2002 and $160.8 million in 2001.

[2] 2001 net capitalized costs include $8.6 million related to discontinued operations.

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, 2002[1]					
Sales and other operating revenues	$748.4	1,034.9	1,044.3	1,138.9	3,966.5
Income from continuing operations before income taxes	3.7	40.5	43.4	64.1	151.7
Income from continuing operations	2.4	12.9	36.5	45.7	97.5
Discontinued operations	.2	1.0	.9	11.9	14.0
Net income	2.6	13.9	37.4	57.6	111.5
Income per Common share – basic					
Income from continuing operations	.03	.14	.40	.50	1.07
Discontinued operations	—	.01	.01	.13	.15
Net income	.03	.15	.41	.63	1.22
Income per Common share – diluted					
Income from continuing operations	.03	.14	.40	.49	1.06
Discontinued operations	—	.01	.01	.13	.15
Net income	.03	.15	.41	.62	1.21
Cash dividend per Common share	.1875	.1875	.20	.20	.775
Market price of Common Stock[2, 3]					
High	48.18	49.70	43.72	46.10	49.70
Low	38.25	40.95	32.47	38.15	32.47
Year Ended December 31, 2001[1]					
Sales and other operating revenues	$961.8	1,045.5	992.2	744.5	3,744.0
Income from continuing operations before income taxes	153.9	246.2	68.6	33.4	502.1
Income from continuing operations	96.4	162.1	41.0	28.9	328.4
Discontinued operations	1.4	.5	.7	(.1)	2.5
Net income	97.8	162.6	41.7	28.8	330.9
Income per Common share – basic[3]					
Income from continuing operations	1.06	1.80	.45	.32	3.63
Discontinued operations	.02	—	.01	—	.03
Net income	1.08	1.80	.46	.32	3.66
Income per Common share – diluted[3]					
Income from continuing operations	1.06	1.78	.45	.31	3.60
Discontinued operations	.02	—	.01	—	.03
Net income	1.08	1.78	.46	.31	3.63
Cash dividends per Common share[3]	.1875	.1875	.1875	.1875	.75
Market Price of Common Stock[2, 3]					
High	34.50	43.92	42.85	42.49	43.92
Low	27.62	33.57	33.27	34.00	27.62

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

[1] The effect of nonrecurring gains (losses) on quarterly net income are reviewed in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 10 and 11 of this Form 10-K report. Quarterly totals, in millions of dollars, and the effect per Common share of these special items are shown in the following table.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2002					
Quarterly totals from continuing operations	$ —	—	7.9	(14.6)	(6.7)
Quarterly totals from discontinued operations	—	—	—	10.6	10.6
Per Common share from continuing operations – basic	—	—	.09	(.16)	(.07)
Per Common share from discontinued operations – basic	—	—	.09	(.16)	(.07)
Per Common share from continuing operations – diluted	—	—	—	.12	.12
Per Common share from discontinued operations – diluted	—	—	—	.12	.12
2001					
Quarterly totals	$ —	67.6	—	—	67.6
Per Common share – basic[3]	—	.75	—	—	.75
Per Common share – diluted[3]	—	.74	—	—	.74

[2] Prices are as quoted on the New York Stock Exchange.
[3] Amounts have been adjusted to reflect the Company's two-for-one stock split effective December 30, 2002.

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

(Millions of dollars)	Balance at January 1	Charged to Expense	Deductions	Other*	Balance at December 31
2002					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 11.3	.8	(2.7)	(.1)	9.3
Deferred tax asset valuation allowance	67.7	21.9	—	—	89.6
Included in liabilities:					
Accrued major repair costs	44.6	25.0	(17.0)	.4	53.0
2001					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 10.2	2.3	(1.2)	—	11.3
Deferred tax asset valuation allowance	61.0	6.7	—	—	67.7
Included in liabilities:					
Accrued major repair costs	34.3	21.1	(10.5)	(.3)	44.6
2000					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 8.3	2.1	(.2)	—	10.2
Deferred tax asset valuation allowance	57.4	3.6	—	—	61.0
Included in liabilities:					
Accrued major repair costs	22.1	22.8	(10.1)	(.5)	34.3

* Amounts represent changes in foreign currency exchange rates.

GLOSSARY OF TERMS

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 600 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
green fuels or clean fuels
low-sulfur content gasoline and diesel products
hydrocarbons
organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products
on stream
commencement of oil and gas production from a new field
3D seismic
three-dimensional images created by bouncing sound waves off underground rock formations that are used to determine the best places to drill for hydrocarbons
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

Exhibit 10.1

MURPHY OIL CORPORATION

1992 STOCK INCENTIVE PLAN

(As Amended May 14, 1997)

SECTION 1. PURPOSE

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

SECTION 2. DEFINITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

“Plan” shall mean this 1992 Stock Incentive Plan.

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

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

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

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

SECTION 3. ADMINISTRATION

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

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

SECTION 4. STOCK SUBJECT TO THE PLAN

The maximum number of shares available for Awards under the Plan in each calendar year during any part of which the Plan shall be in effect shall be one-half of one percent (0.5%) of the total issued and outstanding shares as of December 31 of the immediately preceding year, subject to Section 11 of the Plan. Any and all such shares may be issued in respect of any of the types of Awards; provided, however, no more than fifty percent (50%) of the shares available shall be subject to Incentive Stock

Options granted under the Plan and that no more than fifty percent (50%) of the shares available for Awards under the Plan shall be issued in respect of Restricted Stock. Unless otherwise determined by the Committee, all shares available in any year that are not granted under the Plan will not be available for grant for subsequent years. “Maximum Grants.” Notwithstanding any provision contained in this Plan to the contrary, the maximum number of shares of Common Stock for which Incentive Stock Options, Nonqualified Stock Options, and Stock Appreciation Rights may be granted under the Plan to any one Employee for any calendar year is 100,000.

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

SECTION 5. ELIGIBILITY

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

SECTION 6. STOCK OPTIONS

A. Grant of Options and Price

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

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

B. Exercise

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

C. Payment of Shares

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

SECTION 7. STOCK APPRECIATION RIGHTS

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

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

SECTION 8. RESTRICTED STOCK AWARDS

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

The Committee shall establish performance measures for each Restricted Period on the basis of such criteria and to accomplish such objectives as the Committee may from time to time, in its sole discretion, determine. Such measures may include, but shall not be limited to, total shareholder return, growth in cash flow per share, growth in earnings per share, return on assets, or return on stockholder equity. The Committee may from time to time establish different performance objectives for certain operating subsidiaries or sectors of the business. The maximum number of shares of restricted stock which can be granted pursuant to the Plan will be 50,000 shares per year to any one Employee. Currently, the performance criteria for the determination of the performance-based restricted shares is the 5-year total shareholder return for Murphy Oil Corporation as compared to a peer group of six companies. The Committee may from time to time establish a different performance criteria.

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

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

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

SECTION 9. TERMINATION OF EMPLOYMENT

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

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

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

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

SECTION 10. CHANGE IN CONTROL

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

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

SECTION 11. ADJUSTMENTS UPON CHANGES IN CAPITALIZATION

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

SECTION 12. MISCELLANEOUS PROVISIONS

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

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

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

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

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

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

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

SECTION 13. AMENDMENT, MODIFICATION, AND TERMINATION OF PLAN

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

The Board may terminate the Plan in whole or in part at any time provided that no such termination shall impair the terms of Awards then outstanding under which the obligations of the Company have not been fully discharged.

SECTION 14. GOVERNING LAW

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

EXHIBIT 10.3

MOTOR VEHICLE FUELING STATION
MASTER GROUND LEASE AGREEMENT

Between

WAL-MART STORES, INC., LESSOR

And

MURPHY OIL USA, INC., LESSEE

MOTOR VEHICLE FUELING STATION MASTER GROUND LEASE AGREEMENT

This Agreement (the "Agreement"), dated as of the 12th day of November 1998 is by and between WAL-MART STORES, INC., a Delaware corporation, with offices at 702 S.W. 8th Street, Bentonville, Arkansas 72716 ("Lessor") and Murphy Oil USA, Inc. ("Lessee")

RECITALS

A. Lessor, directly or through one or more of its wholly-owned subsidiaries, owns and operates retail stores under the name of "Wal-Mart" and "Wal-Mart Supercenter" throughout the United States. These stores are located on parcels of land either owned, leased, or subleased by Lessor or one or more of its wholly-owned subsidiaries. References to "Lessor" in this Agreement shall include such of Lessor's wholly-owned subsidiaries, as may be relevant to the context in which the reference to "Lessor" appears.

B. Lessee is a petroleum products refiner and marketer who is in the retail gasoline, convenience store and car wash business and desires to construct a Station on one or more of the Premises or Outlets owned, leased or subleased by Lessor.

C. Recognizing the mutual benefits to be gained from a cooperative effort concerning the development of the Premises, Lessor does hereby lease or sublease to Lessee, and Lessee does hereby lease or sublease from Lessor, the Premises as provided for in this Agreement, setting forth their respective rights and obligations with regard to the Premises and the development of the Stations.

Therefore, in consideration of the mutual covenants and agreements contained herein, Lessor and Lessee hereby agree as follows:

DEFINITIONS

For purposes of this Agreement, the following terms shall be defined as follows:

"Lessee's Work" shall mean all physical improvements and related development of a Premises as herein provided for, including but not limited to canopies, buildings, equipment, piping, installation, construction, grading and paving.

"Cost of Lessee's Work" shall mean all reasonable costs incurred in constructing a Station, including but not limited to payments to third parties for labor and materials incorporated in Lessee's Work, plus all payments to third parties for direct development costs in connection with Lessee's Work including but not limited to permit fees, legal fees, access fees and water and sewer hook-up fees.

"Premises" shall mean that portion of the land that is part of Lessor's property (which is owned or leased) and which is leased or subleased to Lessee by Lessor pursuant to this Agreement. Each Premises shall be identified on a site plan submitted as part of Exhibit A and more particularly described in Exhibit C

"Station" shall mean the motor vehicle fueling facility constructed on the Premises by Lessee, including any car wash and/or convenience store and all improvements, fixtures and equipment located thereon or used in connection therewith.

"Store" shall mean the Wal-Mart store and real property or Wal-Mart Supercenter store and real property on which the Premises is or could be located.

"Outlot" shall mean a parcel of land which is part of the original parcel acquired in conjunction with the construction of a Store by Lessor, usually bordering the major or secondary access artery and which may be available for sale or lease for retail development.

"Delivery Date" shall be the date that all permits necessary to begin construction of the Station are obtained.

"Rent Accural Date" shall mean the earlier of (i) the date a Station opens to the public for business, or (ii) 120 days after the Delivery Date.

LIST OF EXHIBITS

Exhibit A - (furnished to Lessee by Lessor) shall contain a list of Stores with a site plan for each Store reflecting thereon the proposed location, size and configuration of a portion thereof which is thereby offered by Lessor to Lessee to lease as a proposed Premises to become subject to this Agreement. Each Exhibit A shall identify any requirements of Lessor (including without limitation any permissive or mandatory business formats, operations, activities, merchandise or services) and any known restrictions with respect to the proposed Premises (including without limitation zoning matters, easements and restrictions. Exhibit A may be supplemented by additional Exhibits A from time to time, and at any time, by Lessor.

Exhibit B - (furnished to Lessor by Lessee) shall contain a list, by Store, of those proposed Premises offered by Lessor on an Exhibit A, which Lessee accepts as a Premises subject to this Agreement, and a list by Store of those proposed Premises which Lessee rejects. Any Premises not listed as accepted on an Exhibit B in accordance with this Agreement shall be deemed to have been rejected by Lessee. Lessee shall be deemed to have taken possession of the Premises and this Agreement shall be in effect as to each accepted Premises as of the date of Exhibit B.

Exhibit C - (furnished to Lessor by Lessee within ninety (90) days after Lessee opens to the public for business at the Premises) shall be the Addendum for each Premises that is subject to the provisions of this Agreement. The Addendum shall include (i) Lessor's Store number and Store address, and the Premises address, (ii) a site plan reflecting the location and legal description of the Store and the Premises and indicating Lessee's equipment used and the location of such equipment on the Premises and utility easements (if any), (iii) an itemization of the actual Cost of Lessee's Work, (iv) the Delivery Date, (v) the Rent Accrual Date, (vi) a certification by Lessee that the Station has been constructed and equipped and all improvements have been made in accordance with the plans and specifications as approved by Lessor and (vii) proof of separate assessment of the Premises for real property tax purposes or verification that the Premises cannot be separately assessed (as required by Article 10.1). C

Exhibit D - (furnished to Lessor by Lessee) shall be a description of the standard site plans furnished to Lessor by Lessee at the time of execution of this Agreement.

Exhibit E - shall be the schedule of rents.

Exhibit F - shall be those Stations that were open to the public as of September 30, 1998 under the 1996 Agreement (as defined in Article 28.1).

ARTICLE 1.
SITE SELECTION

1.1 [Deleted]

1.2 Final Plans and Specifications

Prior to commencing construction of any improvement on a Premises, Lessee (at Lessee's cost) shall provide Lessor with Lessee's final, specific, detailed plans and specifications for the construction of the Station on each Premises and shall obtain the approval of Lessor. Lessor shall approve or disapprove each submission of plans and specifications within forty-five (45) days, failing which they shall be deemed to have been approved by Lessor.

ARTICLE 2.
STATION CONSTRUCTION AND MODIFICATIONS

2.1 Station Construction.

a. Lessee shall, in a timely fashion, pursue permits with the intent to construct or cause to be constructed at each Premises a Station conforming to the specifications mutually agreed upon by both Lessor and Lessee, to be opened to the public for business timely and otherwise in accordance with the provisions of this Agreement. Lessee will, at Lessee's expense, cause a survey of the Premises to be conducted, which will become the basis for the site plan in Exhibit C. Lessee shall bear all costs in association with Lessee's Work. Lessee shall give Lessor notice (i) of the projected date of commencement of construction at the Premises at least ten (10) days prior thereto, and (ii) of the projected date of opening to the public for business at the Premises at least ten (10) days prior thereto. Within ninety (90) days after the date Lessee opens to the public for business at the Premises, Lessee shall furnish to Lessor Exhibit C.

b. Lessee shall, at Lessee's cost, secure all necessary zoning, permits, licenses and other required regulatory approvals necessary to begin and complete construction and to open to the public for business at the Premises in accordance with this Agreement. Lessor shall cooperate with Lessee in securing such approvals. To the extent available, Lessor shall supply Lessee with site plans including elevations and grading, drainage diagrams, storm sewer and utility line layouts and environmental site evaluations, including soil studies related to the area of the Premises, with Lessee bearing any expense of copying or reproduction. Lessee shall furnish a copy of the building permit to Lessor within one (1) week of its issuance.

c. All construction shall be done in a manner so as not to materially interfere with Lessor's business and in compliance with this Agreement. Prior to entering upon the Premises, Lessee shall provide Lessor with a certificate of insurance as outlined in Article 13. All construction shall be prohibited at a Premises during the period of November 1st - December 31st of any calendar year unless otherwise approved in writing by Lessor. At all times construction equipment and materials shall be contained in an area enclosed by a 6 foot high chain-link fence or OSHA approved safety fencing no less than 4 feet high and be designated as a construction area on site and in construction plans. All work done by Lessee shall be performed in a good and workmanlike manner, in compliance with all applicable governmental laws, codes, rules and regulations, and free of any liens for labor and materials and subject to such requirements as Lessor may impose. Lessee shall indemnify and hold harmless Lessor against any loss, liability, damage, cost or expense resulting from Lessee's Work, except for any loss, liability or damage resulting from gross negligence by Lessor.

2.2 Modifications.

During the term of this Agreement with respect to any Station, Lessee shall make no other structural alterations or improvements to, and shall place no other equipment or other facilities on the Premises except in accordance with the approved plans and specifications. If Lessee wishes to make additional material changes to the Station or Premises, Lessee must request approval from Lessor in writing. Routine equipment replacement and facility maintenance shall not be considered a material change. In performing any such alterations or improvements, Lessee will ensure that such activities do not prevent such Station from performing its intended functions for any length of time in excess of the time reasonably necessary to so repair, remodel, modify or reconfigure any such Station.

ARTICLE 3.
EXCLUSIVE USE AND RESTRICTIVE COVENANTS

3.1 Use.

a. Each Premises is leased to and shall be used by Lessee solely for the purpose of installing, operating and maintaining thereon a Station and other uses, if any, identified on Exhibit A for the purpose of selling and dispensing to the general public motor fuels, convenience store products and car washes of the type identified and if and to the extent identified on Exhibit A hereto, in accordance with the provisions of this Agreement, and for no other purpose or purposes whatsoever without the specific prior approval of Lessor in each instance as provided for herein.

b. During the term of this Agreement, Lessor agrees that Lessee shall have the exclusive right to operate each Station at the Stores at which a Premises is located and that Lessor shall not construct or operate a motor vehicle fueling facility, convenience store or car wash at any Store upon which a Premises is located nor grant to any other person or entity any right to construct or operate a motor vehicle fueling facility, convenience store or car wash at any Store upon which a Premises is located, provided, however, if Lessee constructs and operates a Station without a car wash, Lessor shall not be restricted in any way from entering into an agreement with another party to construct and operate a car wash at a Store upon which a Premises is located. Lessor agrees, however, that it will not enter into an agreement with another party to construct and operate a car wash at a Store upon which a Premises is located without first offering the right to construct and operate the car wash to Lessee. Upon receipt of written notification by Lessor of the offer, including the terms and conditions of the offer, Lessee shall have ten (10) days within which to notify Lessor of Lessee's acceptance of such offer under the same terms and conditions. If Lessee fails to so notify Lessor, Lessor may proceed with the proposed agreement with another party to construct and operate a car wash upon the same terms and conditions as presented in the offer to Lessee. If the terms and conditions of the offer substantially change, Lessor is obligated to provide Lessee with an opportunity to exercise its right as outlined above.

c. Lessor agrees that it will not knowingly sell or lease an Outlot at a Store for the express purpose of use as a Station (with or without a convenience store or car wash in conjunction therewith) without first offering to sell or lease such Outlot to Lessee upon the same terms and conditions as the offer Lessor wishes to accept. Upon receipt of written notification by Lessor of the offer, including the terms and conditions of the offer, Lessee shall have ten (10) days within which to notify Lessor of Lessee's acceptance of such offer under the same terms and conditions. If Lessee fails to so notify Lessor, Lessor may proceed with the proposed sale or lease of such Outlot upon the same terms and conditions as presented in the offer to Lessee. If the terms and conditions of the offer substantially change, Lessor is obligated to provide Lessee with an opportunity to exercise its right of first refusal as outlined above.

d. Proposed Premises which are offered to but not accepted by Lessee as a Premises in accordance with this Agreement shall not be subject thereafter to this Agreement in any respect, including without limitation this Article 3.

3.2 Restrictive Covenants.

a. Lessor and Lessee agree that the Stations may sell any non-fuel products, so long as such products are not offered for sale in bulk quantities, subject to the following:

i) Lessee may not sell beer in a quantity package greater than a "12 pack", soft drinks in a quantity package greater than a "12 pack" and cigarettes in cartons, but cigarettes may be sold on an individual package or multi-pack (in quantities no greater than three) basis.

ii) Lessee agrees not to sell, lease or rent pornographic materials or drug related paraphernalia at its Stations.

iii) Lessee agrees not to sell tires or automotive batteries at its Stations.

iv) Lessee may install ATM banking facilities at the Station provided such ATMs are approved by Lessor in writing and are not restricted by other agreements Lessor may have requiring exclusivity. Such approval will not be unreasonably withheld by Lessor.

v) Lessee may install or operate fast food franchise offerings which do not have on-site seating, provided such offerings are approved by Lessor in writing and are not restricted by other agreements Lessor may have relating to the Premises requiring exclusivity. Such approval will not be unreasonably withheld by Lessor.

b. Lessee agrees that it will not, during the term of this Agreement, enter into any agreements to supply or operate motor vehicle fueling facilities on parking lot sites (excluding Outlots) with Lessor's competitors that are in substantially the same business as the formats currently known as "Wal-Mart" or "Wal-Mart Supercenter nor on parking lot sites (excluding Outlots) of grocery stores or supermarkets having 15,000 square feet or more of total building area. This covenant shall apply only to those states listed under Article 1.1.d. Lessee also agrees if it directly or indirectly supplies or operates motor vehicle fueling facilities as described above, said stations will not bear the name of "Murphy USA" or any other name which is the same as or confusingly similar to any name Lessee may use at Premises covered by this Agreement

ARTICLE 4.
GRANT AND TERM

4.1 Lease of Premises

a. In consideration of the rents, covenants and agreements herein reserved and contained on the part of Lessee to be performed, Lessor does hereby lease and demise unto Lessee, and Lessee does hereby lease or sublease from Lessor, each of the Premises.

b. It is understood that the Premises may, in some instances, be owned by a third party and leased by Lessor from such third party, and in such event consent from the third party lessor may be required for Lessor to sublease the Premises to Lessee. Lessor shall be responsible for obtaining such third party consent when necessary, to the extent such consent can be obtained without the payment of money or the giving of other consideration by Lessor. If Lessor cannot obtain such third party consent, then the Premises shall be removed from this Agreement.

c. It is further understood that if Lessor is the lessee of a Store on which a Premises is located, or if a Store and Premises are located in a shopping center owned in part by a third party, there may be certain areas of the shopping center or of such Premises which are designated for the joint use of some or all the tenants in the shopping center, and the lease by Lessor to Lessee of such Premises is made subject to the provisions of any such lease or other agreement, (including an obligation to pay common area maintenance charges) and to any such existing third party rights.

d. Lessee shall be responsible for accomplishing, at its expense, any platting, re-platting or other steps which may be required by applicable laws, ordinances and regulations in connection with this Agreement, including but not limited to the cost of any relocating of landscaping, drainage, curbing, parking spaces or other improvements which may be necessitated.

e. The lease to Lessee is subject to any existing easements, rights of way, conditions, covenants and restrictions that may affect the Premises.

4.2 Term and Options to Renew.

a. The term of this lease shall commence as to each Premises on the Rent Accrual Date and shall continue for ten (1O) years, unless sooner terminated pursuant to the provisions of this Agreement. Lessor and Lessee acknowledge the Stations that were subject to the 1996 Agreement (as defined in Article 28.1) and were open to the public as of September 30, 1998, are identified on Exhibit F of this Agreement and the original lease term will be for the time period prescribed on Exhibit F.

b. Subject to Article 4.2.c. below Lessee shall have two (2) successive five (5) year options to renew this Agreement as to each Premises, which options shall automatically be exercised unless Lessee provides 6 months prior written notice to Lessor of its intent not to exercise. Options one (1) and two (2) shall be subject to the same terms and provisions of this Agreement and subject to the rental payments outlined in Exhibit E (the "Rent Schedule"). At the end of the options the parties may enter into good faith negotiations for additional option periods.

c. If the term of Lessor's lease on a Store, to which a Premises relates, expires prior to the expiration of an original term or an exercised renewal option, then in that event the original and option terms with respect to such Premises shall expire upon the expiration of Lessor's lease, it being understood that Lessor shall not be obligated to exercise any option or otherwise enter into any agreement to extend or renew a Store lease in order to provide sufficient lease term to cover Lessee's original lease term or the term of any options to renew this Agreement as to the related Premises.

4.3 Condition of the Premises.

Except as expressly provided in Article 5 below or otherwise agreed in writing signed by the parties, Lessee accepts each of the Premises in "as is" condition at the date of the Exhibit B acceptance by Lessee of the offer to lease such Premises.

4.4 Opening of Stations: Removal of Premises from Agreement.

a. Not later than one (1) year after the Premises has been offered, Lessee shall open a Station for business on such Premises in accordance with the provisions of this Agreement.

b. In the event the Station does not open for business within 120 days (excluding any days in November and December during which Lessor precludes Lessee from pursuing construction) from the Delivery Date then a monthly flat fee will be paid to Lessor by Lessee for the individual Station and Premises until it opens for business. This restriction is exclusive of the November and December construction moratorium as may be applicable. The foregoing payment is an amount which is agreed upon by the parties as liquidated damages to compensate Lessor for the damages suffered by it due to Lessee's failure to open and operate the Station(s) within 120 days after the Delivery Date(s). The parties agree that Lessor's damages due to such failure would be impossible to determine with reasonable certainty, by reason of which the parties have agreed upon the foregoing liquidated damages as Lessor's sole and exclusive remedy for such failure by Lessee.

c. Lessee shall have the right to elect to remove from this Agreement up to an aggregate of thirty percent (30%) of the total number of Stores that have been or will be offered. Lessee may remove a Store from this Agreement by giving Lessor written notice of such election. Thereupon arid thereafter, this Agreement shall terminate as to such Premises, and Lessor shall have no obligation to replace such Premises with another Premises.

d. With respect to any Premises (i.) on which a Station has not been opened by Lessee in accordance with the provisions of this Agreement within one (1) year after it is offered to Lessee, (ii) which has not been removed from this Agreement by Lessee in accordance with Article 4.4.c. above, and (iii) on which Lessee has not commenced or is not diligently pursuing completion of the construction, equipping and opening of a Station in accordance with the provisions of this Agreement, Lessor shall have the right to elect to remove such Premises from this Agreement by giving Lessee notice of such election. Thereupon and thereafter, this Agreement shall terminate as to such Premises, and Lessor shall have no obligation to replace such Premises with another Premises.

e. Rent, liquidated damages and other obligations of Lessee under this Agreement shall continue to accrue with respect to a Premises, unless and until such Premises is removed from this. Agreement by Lessee in accordance with the provisions of Article 4,4.c. above or by Lessor in accordance with the provisions of Article 4.4.d. above. Removal of a Premises from this Agreement by Lessee or Lessor shall not terminate any obligations of Lessee which shall have accrued under this Agreement prior to such removal, including without limitation Lessee's obligations under Article 14 and Article 18 of this Agreement. The exclusive use provisions of Article 3.1 shall not apply to any site, which has been removed as a Premises from this Agreement by Lessee or Lessor.

f. Lessor and Lessee agree that any Store offered under this Agreement may be removed by Lessor from the Agreement at any time at Lessor's sole discretion. Such Stores shall not be included in Lessee's right to remove an aggregate of 30% of Stores offered as defined in Article 4.4.C.

g. If Lessee is unable to obtain necessary permitting or zoning required for construction of a Station, Lessee may remove a Store from this Agreement, provided, prior to Store being removed from the Agreement. Lessee shall provide proof to Lessor that all reasonable legal remedies at the local governmental level (short of initiating litigation) have been exhausted. Such Stores shall not be considered part of Lessee's right to remove an aggregate of 30% of Stores offered as defined in Article 4.4.c.

ARTICLE 5.
ENVIRONMENTAL

5.1 Inspection

a. Upon acceptance via Exhibit B of a Premises, Lessee may, at its option, enter upon the Premises and make or cause to be made by a competent and qualified independent contractor(s) reasonably acceptable to Lessor, at Lessee's sole expense, such inquiries, inspections, soil tests, borings and studies (collectively, "Studies") as may be necessary in order to determine the nature, levels and extent of any existing contamination of the Premises and the ground water beneath the Premises; provided, however, that the description and scope of work for the Studies shall be subject to the prior consent of Lessor, in its reasonable discretion. Lessee agrees to conduct each and all such Studies in compliance with all applicable Jaws, rules and regulations and in a professional, competent and workmanlike manner and in a manner which will minimize any interference with the operation of Lessor's business at the Store at which a Premises is located. Promptly upon (but in any event no later than ten (10) business days after) receipt thereof by Lessee, Lessee shall furnish to Lessor a copy of each report or other results of a Study, (each, a "Report"). Each Report shall reflect that it has been prepared by the contractor expressly for the benefit of Lessor as well as Lessee.

b. If a Study or Report indicates the presence of soil or groundwater contamination at the Premises which equals or exceeds current applicable Federal, state or local minimum standards, Lessee shall have the option to not proceed further with work at such Premises, unless Lessor, at Lessor's sole option and expense, performs remediation to reduce such contamination to no more than the said standards. If Lessor does not desire to perform such remediation and Lessee is unwilling to proceed without such remediation, this Agreement shall terminate as to such Premises and Lessor shall reimburse Lessee for the cost of die Studies. Such termination with respect to such Premises shall not affect the rights and obligations of the parties with respect to any other Premises or Stations.

c. The levels of contamination established at the conclusion of the procedures outlined in Article 5.l(a) and 5.1(b) above shall be the "Environmental Base Lines" for the Premises. To the extent Lessee fails to exercise its option to conduct such Studies prior to the earlier of the commencement of construction activities by Lessee on a Premises or the placement of any equipment on such Premises, it shall be conclusively presumed that such Premises contains no contamination.

d. At the conclusion of the Studies, Lessee shall promptly seal or otherwise permanently close any test borings and or wells, remove its equipment and otherwise restore the Premises to its former condition. In the event Lessor and Lessee agree in writing that some or all of the wells should be maintained for future sampling, Lessee may allow the agreed upon wells to remain providing measures are taken to cap and lock said wells so as to minimize potential contamination but allow for future testing.

5.2 Responsibilities After Termination or Non-renewal.

Immediately after termination or non-renewal of this Agreement as to a Premises, Lessee shall (at Lessee's sole expense) cause a Study(ies) to be performed by a competent and qualified independent contractor(s) reasonably acceptable to Lessor, who shall issue a Report, a copy of which shall be furnished to Lessor without charge promptly upon (but in any event no later than ten (10) business days after) receipt thereof by Lessee, sufficient to establish the nature, levels and extent of petroleum based hydrocarbon contamination at the Premises, if present. Each Report shall reflect that it has been prepared by the contractor expressly for the benefit of Lessor as well as Lessee. Lessee shall (at Lessee's sole expense) perform all remediation and take all steps necessary to reduce any contamination to the Environmental Base Lines resulting from Lessee's operation of the Station, including without limitation the acts of third party invitees of Lessee, and shall otherwise be responsible for, indemnify and hold harmless Lessor against any existing petroleum based hydrocarbon contamination in excess of such Environmental Base Lines to the extent required by any applicable present or future Federal, State or Local laws or regulations. Lessee shall not be responsible to the extent that any such contamination has no connection with Lessee's operation of the Station and is caused by a third party which is not an invitee of Lessee. Lessor shall provide Lessee reasonable access to the Premises for the purpose of performing Lessee's obligations hereuuder.

ARTICLE 6.
OPERATING CONDITIONS

[Deleted]

ARTICLE 7.
RENT

7.1 Rent.

For each Station, there shall be no rent or other charge due or payable by Lessee with respect to any period prior to the Rent Accrual Date. From and after the Rent Accrual Date, Lessee agrees to pay rent and/or liquidated damages ("Rent") to Lessor for each Station under this Agreement in accordance with Article 4.4 and Exhibit E hereto (the "Rent Schedule").

7.2 [Deleted]

7.3 Documentation.

Upon request, Lessee agrees to furnish to Lessor from time to time, such information and backup documentation as may be requested by Lessor relating to the determination of Rent.

7.4 Payments.

Payments of Rent shall be made via wire transfer, or other method, as directed by Lessor and shall be made for each calendar month not later than the fifth (5th) day of the calendar month following the month for which the rent is calculated. Lessee shall consolidate payments of Rent for all Premises, in a single wire transfer, but Lessee shall simultaneously with each wire transfer send to Lessor supporting documentation electronically for the Rent attributed to each Premises, which shall be identified by the Lessor's number assigned to the Store or other designation agreed upon by Lessor and Lessee, at which the Premises is located. In the event that an electronic submission cannot take place, Lessee agrees to send the supporting documentation to the address indicated in Article 7.2 above or such other address of which Lessee may subsequently be notified in writing by Lessor. If for any reason Lessor does not receive the rent by the due date, Lessor shall promptly notify Lessee, If Lessee does not cure within five (5) business days from the date of receipt of the notice to cure from Lessor, payments not made by the sixth (6th) day shall bear interest at a rate equal to Prime Rate (as published by the Wall Street Journal) plus four percent (4%) from the sixth (6th) day of the month.

7.5 Alternate Fuels.

Lessor and Lessee agree that prior to the introduction or installation of automotive fuels other than gasoline or diesel at any Station, both parties will agree to a form of measurement upon which the rent is calculated in this Agreement. The rent will then also apply to the new fuel type.

ARTICLE 8.
COMPLIANCE WITH LAW; INGRESS AND EGRESS

8.1 Compliance with Laws and Regulations.

Lessee shall, at all times, maintain and conduct its business, insofar as the same relates to Lessee's use and occupancy of the Premises, in a lawful manner, and in compliance with all governmental laws, rules, regulations and orders applicable to the business of Lessee conducted at the Station, including those with respect to storage, handling, discharge and transport of any material or product deemed hazardous to the extent of Lessee's responsibility.

8.2 Ingress and Egress.

a. Lessor shall at all times allow Lessee, Lessee's agents, suppliers and employees and its customers the right of ingress and egress to the Premises sufficient to conduct and encourage Lessee's business. Lessee and Lessor shall agree on a reasonable route and delivery access for Lessee's commercial delivery vehicles so as to minimize interference with Lessor's Store business.

b. Lessee agrees to not block or disrupt the flow of traffic on Lessor's parking lots and agrees to use its best efforts to make fuel deliveries to the Stations between the hours of 10:00 p.m. and 8:00 a.m.

ARTICLE 9.
MAINTENANCE, REPAIRS AND CLEANLINESS

9.1 By Lessee.

Lessee shall be responsible, at its cost and expense, for all repairs, maintenance and replacements for the Stations and Premises, including but not limited to, the mechanical and electrical equipment and systems which comprise the Stations, and all other fixtures, appliances and facilities furnished or installed on the Premises by Lessee. The maintenance and repair work at the Premises shall be performed by Lessee or its contractors timely, in a good and workmanlike manner and in compliance with all applicable governmental laws, codes, rules and regulations, free of any liens for labor and materials, and subject to such reasonable requirements as Lessor and Lessee may agree from time to time. The Premises shall be kept in clean condition and appearance, and shall be properly operating during the hours that they are open.

ARTICLE 1O.
TAXES

10.1 Lessee's Responsibilities.

a. Lessee shall make every effort to cause the Premises, including all of Lessee's improvements, to be separately assessed for real property tax purposes within 120 days from Delivery Date. If the Premises cannot be separately assessed, Lessee shall provide verification from the appropriate taxing jurisdiction. Such separate assessment of a Premises or verification that it cannot be separately assessed shall be included as part of Exhibit C. Lessee shall be responsible for the timely payment of all general and special real property taxes and assessments and all other government charges levied, assessed or imposed with respect to the Premises and all improvements constructed thereon and all assessments for local improvements, if any, attributable to the Premises. Lessee shall also pay all personal property taxes assessed on its products, trade fixtures and equipment at the Stations or in, under or upon the Premises and also pay general license or franchise taxes and other charges, if any, which may be imposed in connection with the conduct of Lessee's business. If, after Lessee's efforts to do so, the Premises cannot be separately assessed for real property tax purposes, Lessee shall pay that amount by which such real property taxes have increased by reason of Lessee's improvements to the Premises. Lessee shall have the right to contest, in its and/or Lessor's name, an assessment for and/or levy for any taxes which Lessee is obligated to pay under this article. In the event any such taxes, or charges which are the obligation of Lessee herein are assessed and paid by Lessor, Lessee shall reimburse Lessor therefor upon Lessor's demand and presentation to Lessee of receipted bills but Lessor shall not be entitled to reimbursement by reason of Lessor's delinquent payment for any penalties or interest; or if the bills for any such taxes or charges are received by Lessor prior to the date penalty and/or interest begins to accrue and Lessor fails to forward such bills in a timely manner to Lessee, Lessee shall proceed to pay such bills but any penalties or interest shall be charged to Lessor as a result of Lessor's failure to forward such bills in a timely manner. In addition to the above, Lessee shall furnish to Lessor proof of payment of real property taxes for each Premises.

ARTICLE 11.
UTILITIES AND MAINTENANCE FEES

11.1 Utility Charges.

a. Lessee shall pay for all utility services, including natural gas, electricity, domestic water, sewer and all other utility services furnished to Lessee for use in the Premises. All such utility services shall be separately metered and charged to Lessee directly by the utility companies.

b. Lessee, within 120 days from the Delivery Date, shall certify to Lessor that all utility servicing the Premises are separately metered. Certification that the Stations utilities are separately metered shall become a part of Exhibit C.

11.2 Easement.

To the extent it has the right or ability to do so, Lessor agrees to grant to Lessee a non-exclusive utility easement to serve each of the Premises. To the extent Lessor lacks the power to grant such an easement, Lessor will use reasonable efforts (but not requiring the expenditure of funds) to obtain such an easement from those having the power to grant the same. Lessee agrees to bear the cost of bringing utilities to the Premises, including any cost of obtaining an easement from others than Lessor to the extent required under this Agreement.

ARTICLE 12.
FIXTURES, SIGNS AND ALTERATIONS

12.1 Signs.

a. Lessee shall obtain all permits and erect all signs at the Stations in compliance with all applicable governmental laws, codes, rules and regulations, as well as all applicable leases, covenants, restrictions, agreements or other instruments affecting the property. All signs shall be subject to approval by Lessor as to location, content, appearance and all other aspects and shall be maintained by Lessee in a neat and clean condition. No other signs will be placed on or above the Premises or elsewhere on the Store property without the prior written consent of Lessor. In no event shall hand-written signs be permitted at or on the Premises.

b. Lessee shall make diligent efforts where appropriate to establish and maintain signage identifying Lessee's business on what is commonly known as "services at next exit" Interstate signage.

12.2 Alterations.

Lessee may, from time to time during the Lease Term, make any structural alterations or changes to the Stations, which are in accordance with Lessee's Work, or as may otherwise be approved by Lessor and may make any nonstructural alterations that Lessee may desire. All such alterations or changes shall be made by Lessee or its contractor in a good and workmanlike manner, in compliance with all applicable governmental laws, codes, rules and regulations, free of any liens for labor and materials and subject to such reasonable requirements as Lessor and Lessee may agree to or as may be required by any agreement to Lessor affecting the Premises. All alterations or changes Lessee may make in the Premises shall be Lessee's responsibility to maintain and repair in the manner set forth in this Agreement.

ARTICLE 13.
LIABILITY INSURANCE

13.1 Liability Insurance.

Lessee agrees to obtain and keep in force and effect at all times, with insurers reasonably acceptable to Lessor, commercial general liability insurance with respect to the Stations and Premises, with minimum limits of liability of five million dollars ($5,000,000) combined coverage per occurrence; environmental liability insurance with minimum limits of liability of five million dollars ($5,000,000) per Station; employer's liability insurance with minimum limits of five million dollars ($5,000,000); and statutory worker's compensation insurance as required by applicable law with a waiver of subrogation where permitted by law. Each such insurance will name Lessor, its subsidiaries and affiliates as additional insureds and will contain a provision that it is cancelable only upon not less than (30) days' notice in writing to Lessor. Upon request, Lessee agrees to provide Lessor copies of the declaration page(s) of the policy(ies) reflecting all of the foregoing. Lessee may self-insure any or all of the above coverages except environmental liability, so long as Lessee maintains a net worth of or more. Prior to entering any Premises, Lessee will provide Lessor evidence of insurance coverage. Lessee may self-insure as to environmental liability so long as Lessee maintains a net worth of or more.

ARTICLE 14.
INDEMNIFICATION

14.1 Indemnification of Lessor.

Lessee shall indemnify Lessor, its directors, officers, agents, employees and owners to the extent of their interest in the Premises, and save them harmless from and against any and all claims, actions, damages, liability, and expense, including, without limitation, reasonable attorneys' fees in connection with loss of life, personal injury, or damage to property arising from or out of any occurrence in, upon, or at the Premises, or the occupancy or use by Lessee of die Premises or any part thereof, or occasioned wholly or in part by any act or omission of Lessee, its agents, employees or contractors, except to the extent caused by the act or omission of Lessor, its agents, employees or contractors.

14.2 Indemnification of Lessee.

Lessor shall indemnify Lessee, its directors, officers, agents and employees and save them harmless from and against any and all claims, actions, damages, liability and expense, including, without limitation, reasonable attorney's fees in connection with loss of life, personal injury or damage to property arising from or out of any occurrence in, upon or at the Stations or the Stores to the extent caused by any act or omission of Lessor, its agents, employees or contractors.

ARTICLE 15.
ADVERTISING

15.1 Restriction on References to Other Party.

Neither Lessor nor Lessee shall refer to the other party in advertising nor use the other party's logos, trademarks, trade dress, or service marks without the prior written consent of the other party; provided, however, each party may, without obtaining the consent of the other party, include the addresses of or otherwise identify the Stores and/or the Stations in a directory, map or other listing or depiction of the Stations and/or the Stores. Each of Lessor and Lessee acknowledges that the other party's logos, trademarks, trade dress, and service marks are the sole property of the other party, and this Agreement gives neither party any rights with respect to the logos, trademarks, trade dress or service marks of the other party. Lessee shall conspicuously identify itself as owner/operator with respect to each Station at each Premises and in connection with any advertising.

15.2 Right to Advertise on Premises,

a. Lessor shall have the exclusive right to utilize all spanners for advertising on the Premises and on Lessee's Equipment (including electronic display at point of sale). The spanners shall not carry the trademark, mention or promote any item which is in competition with Lessee's business or product lines of refining and marketing petroleum products such as motor fuels and gasoline. All electronic messages shall be approved by Lessee and shall conform to Lessee's standards.

b. Lessee shall have the exclusive right to utilize all pump toppers for advertising on the Premises. The pump toppers shall not carry the trademark, mention or promote any retail competitor which is in competition with Lessor or items which are in competition with Lessor's business or product lines.

c. In order to assist Lessor in promoting its Tire & Lube Express and Store automotive sales businesses, Lessee shall make available point of sale and promotional space as, when and where requested by Lessor for items such as tire and automotive displays, so long as these activities do not interfere with sales at the Stations. Lessee shall also allow Lessor to conduct tire and lube promotions by Lessor's sales associates at the Station so long as these activities do not interfere with Station sales.

ARTICLE 16.
EMERGENCY NOTIFICATION

16.1 Emergency Notification.

Lessee and Lessor shall each keep the other party informed at all times of the name(s) and/or telephone number(s) with respect to each of the Premises, for the other party to contact, at any time of day or night, to report activities or circumstances existing at any of the Stores or Premises for Lessor's or Lessee's prompt attention. Notwithstanding the foregoing and that a party may from time to time make such reports to the other party, neither party shall have any obligation whatever to observe, monitor, report on, control, respond to or otherwise deal in any manner with any activities or circumstances whatever at a Store (in the case of Lessee) or at a Premises (in the case of Lessor). Except as provided in Article 9.1 above, Lessee shall be solely responsible for the Premises, for Lessee's property and for all activities of Lessee at the Premises. Lessor shall be solely responsible for its Store, for its property and for all activities of Lessor at its Store.

ARTICLE 17.
DAMAGE BY FIRE OR OTHER CASUALTY

17.1 Notice.

Lessee shall give immediate written notice to Lessor of any damage caused to a Premises or Station by fire or other casualty.

17.2 Damage.

Subject to provisions of 17.3 below, if during the Lease Term a Premises or Station shall be damaged by fire or other casualty, Lessee shall promptly proceed to commence repair of such damage and restore the Premises and Station to substantially its condition at the time of such damage. Subject to zoning laws and building codes then in existence, Lessee shall complete such repairs subject to any-delay, which may result from any cause beyond Lessee's reasonable control. This Agreement shall continue in full force and effect during any such period of repair and restoration.

17.3 Substantial Damage In Last 3 Years of Term.

In the case during the last three (3) years of the Lease Term the Premises or Station shall be substantially damaged or destroyed by fire or other casualty. Lessee shall have the right, to be exercised by written notice to such effect given by Lessee to Lessor within forty-five (45) days after the occurrence of such event, to terminate this Agreement as to such Premises. If Lessee fails to timely give such notice of its election to terminate, this Agreement shall, except as hereinafter provided, remain in full force and effect, and Lessee shall proceed to commence repair or rebuilding of the Premises and Station to substantially its condition at the time of such damage or destruction subject to zoning laws and building codes then in existence, but Lessee shall not be responsible for any delay which may result from any cause beyond Lessee's reasonable control. For purposes of this article, substantial damage shall be defined as damage for which the repair cost is greater than 50% of the cost to rebuild the Station and Premises.

17.4 Operation During Reconstruction.

During any period of reconstruction or repair of the Premises. Lessee shall continue the operation of the Station to the extent practicable.

ARTICLE 18.
LESSOR'S OPTION TO ACQUIRE LESSEE'S WORK;
OBLIGATIONS OF LESSEE UPON TERMINATION

18.1 Lessor's Option to Acquire Station Equipment Upon Termination.

Except in the case of termination due to expiration of the term (original or renewal) which is dealt with in Article 18.2 below, upon termination of this Agreement as to a Premises in accordance with the provisions of this Agreement, Lessor shall have the right, at its option, to acquire all (but not less than all) of Lessee's Work with respect to such Premises, exclusive of any signs, docals or other materials which contain Lessee's Brand identification. Within ten (10) days of the giving to Lessee of a notice of earlier termination by Lessor, or simultaneously with the giving by Lessee of a notice of earlier termination by it, Lessee shall give a notice to Lessor, which shall disclose the unamortlized portion of the Cost of Lessee's Work at each Premises, using a ten (10) year straight line basis beginning on the Rent Accrual Date (the "Unamortized Station Costs"). Lessor shall have the right to audit Lessee's determination of Unamortized Station Costs. Lessor shall have the right to acquire Lessee's Work free and clear of any liens or encumbrances whatever, by giving Lessee notice of its election to do so not later than ten (10) business days prior to the termination of this Agreement with respect thereto. Any addition to or replacement of above or below ground equipment or facilities, as provided for herein, will be added to the Cost of Lessee's Work. Upon termination. Lessee shall deliver to Lessor a bill of sale containing warranties of title and against liens and encumbrances covering all items of Lessee's Work with respect to which Lessor shall have exercised its option to acquire, in exchange for payment by Lessor of the Unamortized Station Costs.

18.2 Expiration of Term.

In the case of termination as to a Premises due to expiration of the term (original or renewal), Lessor shall have the right, at its option, to acquire all (but not less than all) of Lessee's Work with respect to such Premises. Not less than sixty (60) days prior to expiration of the term, Lessee shall give a notice to Lessor which shall disclose the pre-tax net income of Lessee for the Premises for the thirty-six (36) months ending ninety (90) days prior to such termination. In determining such net income, Lessee shall charge or credit to the Premises all related revenues and expenses in accordance with generally accepted accounting principles on a consistent basis throughout the term. Lessor shall have the right to audit Lessee's financial statements relating to the Premises for any or all of the years during which the Premises have been subject to the Agreement. Lessor shall have the right to acquire the Lessee Equipment, free and clear of any liens or encumbrances whatever, by giving Lessee notice of its election to do so not later than ten (10) business days prior to the termination of this Agreement with respect thereto. Upon termination, Lessee shall deliver to Lessor a bill of sale containing warranties of title and against liens and encumbrances covering all items of Lessee's Work with respect to which Lessor shall have exercised its option to acquire, in exchange for payment by Lessor of an amount equal to the higher of such 36-months' net income, as adjusted pursuant to any audit by Lessor, or the Unamortized Station Costs.

18.3 Equipment Removal.

Except where Lessor has exercised its option to acquire the Lessee's Equipment as provided in Article 18.1 and 18.2 above or as herein after provided, not later than sixty (60) days after the date of termination of this Agreement as to a Premises. Lessee shall remove therefrom all of Lessee's Work and shall repair any damage and restore all of such Premises to its former condition. If Lessee fails to remove any of Lessee's Work, Lessor may, at its option, treat the same or any part thereof as abandoned by Lessee, whereupon the same or such part thereof shall be and become the property of Lessor and may be used or disposed of by Lessor as it may see fit, without any obligation to account therefor to Lessee. The acquisition by Lessor of any of Lessee's Work shall not be deemed to be a waiver of any rights of Lessor against Lessee under the Agreement, or otherwise, and shall not be a basis for a claim of assumption of risk or contributory negligence by Lessor, which defenses Lessee expressly waives. If the Premises are leased by Lessor. Lessee shall remove Lessee's Work, repair any damage and restore the Premises in accordance with the foregoing not later than the date of termination of Lessor's lease. If the termination of this Agreement is pursuant to Article 22.1 below, Lessee shall remove the Equipment, repair any damage to Lessee's Work and restore the Premises in accordance with the foregoing no later than the later of (i) sixty (60) days after notice of termination or (ii) the date of termination. No rent shall be payable while Lessee is removing its equipment, repairing damage and restoring the Premises, except in the event of termination pursuant to Article 22.1 below.

ARTICLE 19.
EMINENT DOMAIN

19.1 Partial or Total Condemnation.

If the whole or any part of the Premises shall be taken by any public authority under the power of eminent domain, then and in such event this Agreement shall terminate as to such Premises, unless Lessor and Lessee shall mutually agree in writing, that the property taken is not significant enough to substantially affect the business, in which case this Agreement shall not terminate. In any event, Lessee shall have the right to claim from the condemning authority such compensation as may be separately awarded or recoverable by Lessee in Lessee's own right for the Station, trade fixtures, moving expenses and lost profits of Lessee. All other condemnation rights shall belong to Lessor.

ARTICLE 20.
ASSIGNMENT AND SUBLETTING; SUBCONTRACTING

20.1 By Lessee.

Except (i) in the event of the reorganization or consolidation of Lessee, or (ii) in connection with a deed of trust, mortgage or other pledge to a secured lender of Lessee, Lessee shall not assign this Agreement or any part thereof, or franchise to, subcontract with or otherwise permit any third party to occupy or operate the Premises, the Station or any portion thereof or conduct any activity thereon, without obtaining the prior written consent of Lessor, which consent shall not be unreasonably withheld. Assignment shall not release the assignor from its obligations, past or future, under this Agreement, unless such release is in writing and signed by the releasing party. Provided, however, that the exception in (i) above shall not be construed so as to diminish or impede Lessor's right to purchase as provided in Article 25 below.

20.2 By Lessor.

Lessor, its successors or assignees shall have the right at any time to assign this Lease. Assignment shall not release the assignor from its obligations, past or future, under this Agreement, unless such release is in writing and signed by the releasing party.

ARTICLE 21.
RELOCATED STORES

21.1 Relocated Stores.

a. Lessee acknowledges Lessor's right to close or relocate any Store at any time, however, Lessor agrees that, to the best of its knowledge at that time, no Store will be included on any Exhibit A that is then scheduled to close within five (5) years of the date of such Exhibit A.

b. If Lessor elects to relocate a Store at which a Station is then located during the original term of this Agreement, and if in connection with such relocation Lessor determines (in Lessor's sole discretion) that the relocated store is appropriate for a Station, then Lessor will issue to Lessee an Exhibit A for a proposed Premises at the relocated store.

c. If Lessor relocates or closes (without relocating) a Store at which a Station is then operating, Lessor may at any time thereafter notify Lessee of Lessor's request that Lessee close the Station, in which event Lessee shall, within sixty (60) days after such notice, cease business at such Station, remove therefrom Lessee's Work in accordance with Article 18.3 and surrender the Premises to Lessor, whereupon this Agreement shall terminate as to such Premises. If Lessor makes such a request within the first five (5) years of the term of this Agreement as to a Premises and Lessor has not offered to Lessee a proposed Premises at a relocated store, then in such event Lessor shall pay to Lessee the Unamoritized Station Costs in connection with such Premises.

d. If Lessee is offered the right to relocate a Station along with the relocation of a Store but elects not to relocate the station, Lessee may remain at the closed Store location unless requested by Lessor to close the Station, in which event Lessee shall, within sixty (60) days after such notice, cease business at such Station, remove therefrom Lessee's Work in accordance with Article 18.3 and surrender the Premises to Lessor, whereupon this Agreement shall terminate as to such Premises.

ARTICLE 22.
RIGHT OF TERMINATION

22.1 Lessee's Default.

a. Any one or more of the following events shall be an "Event of Default" under this Agreement:

i. Lessee shall vacate or abandon a Premises;

ii.. This agreement shall be transferred to any other person or party except in the manner herein provided;

iii. This Agreement or a Premises or any part thereof shall be taken upon execution or by other process of law directed against Lessee, or shall be taken upon or subject to any attachment at the instance of any judgment creditor against Lessee, and said taking or attachment shall not be discharged or disposed of within fifteen (15) days after the levy thereof;

iv. Lessee shall file a petition in bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency act of any state, or shall voluntarily take advantage of any such law or act by answer or otherwise, or shall be dissolved or shall make an assignment for the benefit of creditors;

v. Involuntary proceedings under any such bankruptcy law or insolvency act or for the dissolution of Lessee shall be instituted against lessee, or a receiver or trustee shall be appointed of all or substantially all of the property of Lessee, and such proceeding shall not be dismissed or such receivership or trusteeship vacated within sixty (60) days after such institution or appointment;

vi. Lessee shall generally fail to pay its debts as they become due;

vii. Lessee shall fail in any material way to perform any of the other agreements, terms, covenants, or conditions hereof on Lessee's part to be performed, including maintenance of insurance as required by Article 13, and such non-performance shall continue for a period of thirty (30) days after written notice thereof is given by Lessor to Lessee, or if such performance cannot be reasonably had within such thirty (30) day period. Lessee shall not in good faith have commenced such performance within such thirty (30) day period and shall not diligently proceed therewith to completion

b. Upon the occurrence of an Event of Default, Lessor shall have the right to either(i.) give Lessee written notice of intention to terminate this Agreement, either in its entirety as to all Premises or only as to such Premises to which the Event of Default pertains, on the date of such notice or on any later date specified therein, and on the date specified in such notice Lessee's right to possession of the Premises shall cease and this Agreement shall be terminated, or (ii) exercise "self-help" and correct all or part of such failure, in which event Lessee shall, immediately upon demand, reimburse Lessor one hundred ten percent (110%) of the out-of-pocket cost to Lessor of performing such self-help. The remedies of Lessor described in this Article 22 shall be in addition to any other remedies of Lessor available under applicable law or equity in the event of the occurrence of an Event of Default by Lessee.

22.2 Performance Failure.

a. If Lessee shall fail to pay the rent or any other monetary sums required to be paid hereunder on or before the date such sums are due and shall fail to cure the same within five (5) business days after receipt of written notice from Lessor of such failure to pay interest shall accrue pursuant to Article 7.4; provided, however, if such failure to pay exceeds ten (10) days twice within any twelve (12) consecutive months period, thereafter, Lessee shall be required to pay a 15% penalty on any delinquent amounts in addition to any interest accrued pursuant to Article 7.4.

b. If Lessee shall fail to pay the rent or any other monetary sums required to be paid hereunder within ninety (90) days after receipt of written notice from Lessor of such failure to pay, Lessor may terminate this agreement.

c. Except in the event of Force Majeure (as defined in Article 23.2), commencing on the Rent Accrual Date Lessee shall keep the Station open for business for at least ninety percent (90%) of the hours of operation required by Article 6.1 in each calendar month, and if it fails to do so, Lessor may, at its sole option, require Lessee to pay an amount equal to (1) the highest rent paid for any month since the opening of the Station, or (2) the average monthly rent for all stations that have been open for at least six months, whichever is greater.

ARTICLE 23.
MISCELLANEOUS PROVISIONS

23.1 Covenant of Quiet Enjoyment.

Lessee, subject to the terms and provisions of this Agreement concerning payment of the rent and observing, keeping and performing all of the terms and provisions of this Agreement on its part to be observed, kept and performed, shall lawfully, peaceably and quietly have, occupy and enjoy the demised Premises during the Lease Term without hindrance or ejection by Lessor or any persons claiming under Lessor.

23.2 Force Majeure.

Any delay in or failure of performance by either party under this Agreement, except in respect to the obligation to make payment, shall not constitute default if and to the extent such delay or failure is occasioned by any cause reasonably beyond the control of the party affected ("Force Majeure"). Force Majeure occurrences include but are not limited to: acts of God or the public enemy, sabotage, war, mobilization, revolution, civil commotion, riots, strikes, lockouts, fires, accidents or breakdowns of equipment, floods, hurricanes or other actions of the elements, restrictions or restraints imposed by law, rule or regulation or other action or failure to act of governmental authorities, including failure to issue necessary permits or licenses. In any such event, the party claiming Force Majeure shall notify the other party in writing and, if possible, of the extent and duration thereof and shall exercise due diligence to prevent, eliminate or overcome such cause where it is possible to do so and shall resume performance at the earliest possible date. Notwithstanding the foregoing, the party which has received a notice of Force Majeure hereunder shall have the right to delay or suspend its performance hereunder during the period of Force Majeure.

23.3 Provisions Binding.

Except as herein otherwise expressly provided, the terms hereof shall be binding upon and shall inure to the benefit of the successors and assigns, respectively, of Lessor and Lessee. Each term and each provision of this Agreement to be performed by Lessee shall be construed to be both a covenant and a condition and shall run with the land to the fullest extent permitted by law.

23.4 Notice of Default.

In the event of any alleged default on the part of Lessor hereunder, Lessee shallgive written notice to Lessor in the manner herein set forth and Lessor shall have a period of thirty (30) days in which to cure any such default or, if such default cannot be reasonably cured within such thirty (30) day period, in which to in good faith commence such cure and thereafter diligently proceed therewith to completion. In no event shall Lessor be responsible for any indirect or consequential damages incurred by Lessee including but not limited to lost profits or interruption of business as a result of any alleged default by Lessor hereunder.

23.5 Short Form Lease.

At the request of either party, the parties will execute an appropriate short form of this Agreement for purposes of recording with respect to the Premises.

23.6 Rules and Regulations.

Lessee shall comply with all reasonable rules and regulations which may be adopted from time to time by Lessor, and Lessee, Lessee's employees and agents, or any others permitted by Lessee to occupy or enter the Premises, shall at all times abide by said rules and regulations. Lessor may amend, modify, delete, or add new and additional rules and regulations upon notice to Lessee from Lessor thereof. In the event of any material breach of any rules and regulations so established, or any amendments, modifications, or additions thereto, Lessor shall have all remedies in this Agreement provided for in the event of default by Lessee.

23.7 Independent Tenant Status.

a. It is expressly understood and agreed that the relationship created hereunder is that of a tenant and no other. Neither party shall have any control or right to exercise any control whatsoever over the employees of the other party in their performance of this Agreement, and neither party shall have the right nor shall it attempt to exercise the right to establish the rate of pay, benefits, hours of work or other terms or conditions of employment of the employees of the other party. Neither party shall select, supervise, direct or in any other way control or seek to control the employees of the other party. Each party agrees to and warrants that it will comply with all applicable federal, state, local and other laws and regulations relating to wages, the payment of wages, the withholding of sums from wages for taxes and otherwise, and that it will promptly remit to the appropriate recipients all moneys withheld from the pay of employees and all moneys due from it as an employer related in any way to the employment of its employees. Each party further agrees to and warrants that it will comply with all applicable federal, state, local and other laws and regulations relating in any way to employment, including but not limited to those relating to discrimination, veteran's rights, the hiring of the disabled and worker's compensation.

b. Each party agrees to defend, indemnify and hold harmless the other party, its directors, officers, employees and agents, from and against any and ail damages which may be suffered, incurred or asserted in connection with, arising out of or in any way related to any claims asserted against the other party, its directors, officers, employees or agents, by or on behalf of any employee of the party or of any supplier of goods or services to the party, under the workers' compensation act or similar law applicable to the work performed pursuant to this Agreement.

c. Notwithstanding the foregoing, each party recognizes that its agents and employees at the Store and Premises frequently will deal with persons who arc or may be customers of the other party.

23.8 Governing Law; Jurisdiction; Venue.

This Agreement shall be governed by and construed in accordance with the laws of the State of Arkansas (without regard to Arkansas' law respecting conflicts of laws), except to the limited extent, if any, that the laws of the state in which a Premises is located must govern the creation and effect of interests such as the interest of Lessee in such Premises. The parties mutually consent and submit to the jurisdiction of the federal or state courts for Benton County, Arkansas, and agree that any action, suit or proceeding concerning this Agreement shall be brought only in such courts. The parties mutually acknowledge and agree that they will not raise, in connection with any such suit, action or proceeding brought in any federal or state court for Benton County, Arkansas, any defense or objection based upon lack of personal jurisdiction, improper venue, inconvenient form or the like. Notwithstanding the foregoing, if subject matter jurisdiction for any action exists only in the court(s) where a Premises is located, then the parties agree that such action may be maintained in such court(s).

23.9 Notices, Consents, Approvals.

Any notice, consent or approval required, permitted or given in connection with this Agreement shall be in writing and shall be deemed given on the day delivered in person or by courier, or on the third business day after mailed, postage prepaid, by certified mail, return receipt requested, if delivered to or addressed as follow:

If to Lessor:	Wal-Mart Stores, Inc. Attn: Vice-President, Wal-Mart Realty 2001 Southeast 10th Street Bentonville, Arkansas 72712-6489
With a copy to:	Wal-Mart Stores, Inc. Attn: Wal-Mart Realty - Special Projects 2001 Southeast l0th Street Bentonville, Arkansas 72712-6489
If to Lessee:	Murphy Oil USA: INC. Attn: Vice President, Marketing 200 Peach St. El Dorado, AR 71730
With a copy to:	Murphy Oil USA, INC. Attn: Retail Marketing Manager 200 Peach St. El Dorado, AR 71730

Or to such other person or address of which notice hereafter may be given.

23.10 No Waiver.

No delay or omission to exercise any right or power accuring upon any default, omission or failure of performance under this Agreement shall impair any such right or power or shall be construed to be a waiver thereof, but any such right or power may be exercised from time to time and as often as may be deemed expedient. In the event any provision contained in this Agreement should be breached by one party and thereafter duly waived by the other party, such waiver must be in writing signed by the waiving party, shall be limited to the particular breach so waived and shall not be deemed to waive any other breach under this Agreement nor the same breach on any other occasion.

23.11 Severability.

The invalidity or unenforceability of any one or more provisions of this Agreement shall not affect the validity or enforceability of the remaining portions of this Agreement or any part hereof.

23.12 Headings.

The headings appearing in this Agreement are not intended in any manner to define, limit or describe the scope of any such Article or article and are inserted solely as a matter of convenience.

23.13 Entire Agreement.

This Agreement and all Exhibits hereto constitute the entire agreement between the parties and no subsequent change shall be binding unless reduced to writing and signed by the parties hereto.

ARTICLE 24.
CONFIDENTIALITY

24.1 Confidentiality.

Each party recognizes that it may come into possession of information relating to the business of the other party which is not generally known in the industry, which reasonably or logically may be considered to be confidential or proprietary and which might reasonably be expected to do harm to the other party if divulged ("Confidential Information"). Each party agrees, during the term of this Agreement and for a period of two (2) years after termination of this Agreement in its entirety, not to disclose any Confidential Information in whole or in part, to any third persons whatever, nor even to any of its own employees except those having a "need to know" and otherwise to protect the confidentiality of such Confidential Information reasonably and with the same degree of care as it protects its own Confidential Information. Confidential Information of a party shall no longer be subject to the foregoing restrictions if it is or becomes available to the public through no fault of the other party, its directors, officers, employees, agents, attorneys, accountants or representatives, or if it is otherwise known to the other party as shown by written records of the other party at the time of disclosure of the Confidential Information.

ARTICLE 25
RIGHT TO PURCHASE STATION(S)

25.1 Lessor's Right of First Refusal to Purchase Station.

Lessee may not sell or offer for sale all or any portion of a Station without first offering in writing to sell all or such portion of such Station to Lessor upon the same terms and conditions. Lessor may accept such offer by giving notice of such acceptance to Lessee within thirty (30) days after the giving by Lessee to Lessor of notice of such offer. If Lessor does not so accept such offer, Lessee may offer or sell such Station or portion thereof upon such terms and conditions. If Lessee does not close such a sale to a third party within six (6) months after expiration of Lessee's 30-day period of acceptance, Lessee may not thereafter sell or offer to sell all or any portion of such Station without first offering the same to Lessor in accordance with the provisions of this Article.

25.2 Lessor's Right to Purchase in the Event of Acquisition.

In the event that Lessee or Lessee's parent company, Murphy Oil Corporation, shall be acquired or be a party to any merger or consolidation which results in a material change with respect to the management direction of the Stations. Lessor shall have the option to purchase Lessee's Stations at fair market value.

ARTICLE 26
CROSS PROMOTION GIFT CARD

[Deleted]

Use of the Gift Card for the purchase of gasoline at Lessee's Stations is subject to immediate termination at any time at the sole discretion of Lessor without notice to Lessee and without consent of Lessee.

ARTICLE 27.
PRESS RELEASES

27.1 Press Release.

No press releases or other public announcements shall be made by either party at any time regarding the subject of this Agreement, except as are mutually agreed upon by the parties.

ARTICLE 28
TERMINATION AGREEMENT

28.1. Termination of July 31, 1996 Agreement.

a. Lessor and Lessee entered into a "Convenience Store, Car Wash and Motor Vehicle Fueling Station Master Ground Lease Agreement" dated as of July 31, 1996 and amended July 2, 1998 (the "1996 Agreement"). Lessor and Lessee agree that the Stations subject to the 1996 Agreement will from this date forward be included as part of this Agreement. Stations open to the public as of September 30, 1998, that were subject to the 1996 Agreement are identified in Exhibit F of this Agreement and shall have a lease term as stated in Article 4.2. of this Agreement.

b. Lessor and Lessee hereby mutually rescind and terminate the 1996 Agreement and agree that the 1996 Agreement shall hereafter be of no further force or effect. Notwithstanding the foregoing, Lessor and Lessee agree and acknowledge that any and all rights, obligations and liabilities of whatever kind or nature, which vested, arose or accrued under the 1996 Agreement prior to the date of this Agreement, shall and do survive this rescission and termination of the 1996 Agreement.

Executed as of the day and year first above written.

MURPHY OIL USA, INC.

By: /s/

Title: Vice President, Marketing

Date. November 5, 1998

WAL-MART STORES, INC.

By: /s/

Title: Executive Vice President WSI

Date: November 12, 1998

EX. 10.3-28

EXHIBIT A

LISTING OF STORES
SITE PLANS and DESCRIPTION OF LOCATIONS

EXHIBIT B

STORES ACCEPTED / REMOVED BY LESSEE

EXHIBIT C

ADDENDUM

EXHIBIT D

STANDARD SITE PLANS

EXHIBIT E

RENT SCHEDULE "A"

EXHIBIT E
(Page a of two pages)

RENT SCHEDULE "B"

EXHIBIT E
(Page b of two pages)

RENT SCHEDULE "B"

EXHIBIT F

STATIONS FROM JULY 31,1996 AGREEMENT

[Deleted]

FIRST AMENDMENT
To
MOTOR VEHICLE FUELING STATION MASTER GROUND LEASE AGREEMENT

THIS FIRST AMENDMENT is made this 16th day of Sept. 1999 by and between WAL-MART STORES, INC., a. Delaware corporation, with offices at 702 S.W. 8th Street, Bentonville, Arkansas 72716 ("Lessor") and MURPHY OIL USA, INC., a Delaware corporation, with offices at 200 Peach Street, El Dorado, Arkansas 71731 ("Lessee").

WTTNESSETH:

WHEREAS, Lessor said Lessee have entered into a Motor Vehicle Fueling Station Master Ground Lease Agreement dated the 12th day of November 1998, ("Lease Agreement").

WHEREAS, Lessor and Lessee are now desirous of making certain amendments, changes and alterations to said Lease Agreement to reflect accurately their intents and wishes.

NOW, THEREFORE, that for One Dollar ($1.00) and other good and valuable considerations, the sufficiency of which is hereby acknowledged, Lessor and Lessee agree the Lease Agreement shall be amended as follows:

1. Article 9 - Maintenance, Repairs and Cleanliness of the Lease Agreement is amended by adding the following:

   "9.2 Remodel - Lessee agrees to remodel their facility at the same time Wal-Mart remodels their store, unless it is agreed by both Lessor and Lessee that a. remodel is not necessary at the time and/or Lessee's facility is less than three (3) years old.

   Remodel is defined, but is not confined, as:

   1. Repainting of all exterior and interior walls and canopies.
   2. Remodeling restrooms to ensure compliance with Federal ADA guide lines.
   3. Replacement of all exterior doors and/or repairs to existing doors and frames.
   4. Replace floor tile as needed.
   5. Replace ceiling tile as needed.
   6. Replace and/or repair canopy and interior lighting as needed.
   7. Restriping of parking lot.
   8. Replacement of Disabled Parking signs.
   9. Renewal or rejuvenation of landscape area."

2. Exhibit E - Rent Schedule "A" and Rent Schedule "B" of the Lease is amended by adding the following:

   "Minimum Monthly Rent

   III Outlot
   Monthly rent on an Outlot is set by the Lessor's Realty Committee on a site by site basis prior to offering to Lessee. Lessee's acceptance of sites (Exhibit B) signifies their acceptance of the minimum monthly rent due on the outlot."

3. Article 7 --Rent of the Lease Agreement is amended by deleting the first sentence of Section 7.4 and replacing with the following:

   "7.4 Payments - Payments of Rent shall be made via wire transfer, or other method, as directed by Lessor and shall be made for each calendar month not later than the fifteenth (15) day of the calendar month following the month for which the rent is calculated."

Except as hereby modified and amended, all other terms, convenants, and conditions of said Lease dated November 12, 1998 shall continue and remain without change.

IN WITNESS WHEREOF, the respective parties hereto have caused this instrument to be executed as of the date herein written above.

WAL-MART STORES, INC	MURPHY OIL USA, INC.
By: /s/	By: /s/
Its: Director/Wal-Mart Realty/ Special Projects	Its: Senior Vice President Marketing
Attest: /s/	Attest: /s/
Date: September 16, 1999	Date: September 3, 1999

SECOND AMENDMENT
to
MOTOR VEHICLE FUELING STATION MASTER GROUND LEASE AGREEMENT

This Amendment (the "Amendment"), dated as of the 15th day of August 2001, and effective on June 1, 2001, is by and between Murphy Oil USA, Inc., a Delaware corporation, with offices at 200 Peach Street, El Dorado, Arkansas 71730 ("Murphy") and Wal-Mart Stores, Inc., a Delaware corporation, with offices at 702 S. W. 8th Street, Bentonville, Arkansas, 72716 ("Wal-Mart").

RECITALS

A. Murphy is a petroleum products refiner and marketer who owns retail gasoline stations located on leased parcels of land either owned or leased by Wal-Mart or one of its wholly- owned subsidiaries, pursuant to a Motor Vehicle Fueling Station Master Ground Lease Agreement dated November 12, 1998 ("Master Ground Lease").

B. Wal-Mart, directly or through one of its wholly-owned subsidiaries, owns and operates retail stores under the name "Wal-Mart" and "Wal-Mart Supercenter" throughout the United States. These stores are located on parcels of land either owned, leased or subleased by Wal-Mart or one of its wholly-owned subsidiaries. References to "Wal-Mart" in this Amendment shall include such of Wal-Mart's wholly-owned subsidiaries, as may be relevant to the context in which the reference appears.

C. Recognizing the mutual benefits of a cooperative effort to continue developing the Premises and adjacent areas, Murphy and Wal-Mart agree that for the consideration herein described, as well as other good and valuable consideration, the receipt of which is hereby acknowledged, the parties agree to the following terms concerning the installation and operation of ATM's on or adjacent to the Premises.

Therefore, in consideration of the mutual covenants and agreements contained herein, Murphy and Wal-Mart hereby agree to amend the Master Ground Lease by adding the following;

DEFINITIONS

For purposes of this Amendment, the following terms shall be defined as follows:

"ATM Property" shall mean such areas leased or subleased by Murphy which are designated for the location of an ATM. Such area will include the ATM as well as the entire concrete pad area surrounding the ATM.

All other capitalized terms shall have the same meaning as set forth in the Master Ground Lease.

ARTICLE 1.
SITE SELECTION

1.1 Site Selection.

Wal-Mart will notify Murphy in writing of each proposed ATM location that is either on or within a fifty foot radius of the Premises. Only when the proposed ATM. location is on the Premises shall such notification be in the form of final, specific and detailed plans and specifications for the construction and/ or installation of the ATM. Within thirty (30) days of being notified of a proposed location on the Premises, Murphy will accept the location provided that in Murphy's reasonable judgment such location does not interfere with the Station's traffic flow or other Station operations. If Murphy does not accept the location on the Premises, the parties may enter into reasonable discussions in order to reach agreement on the location of the ATM on the Premises. If after reasonable discussions, Wal-Mart and Murphy can not agree on the location of the ATM on the Premises, then neither party will have the right to place an ATM on the Premises. Alternatively, Wal-Mart may choose a new location on its property, that is not part of the Premises, for the placement of the ATM.

ARTICLE 2.
ATM CONSTRUCTION, INSTALLATION AND MODIFICATION

2.1 ATM Construction and/ or Installation

a. Wal-Mart, agrees that each ATM shall be properly permitted by the ATM provider and that construction and/or installation shall be pursued in a diligent manner so as not to unreasonably disrupt Murphy's business,

b. If Wal-Mart is unable to negotiate the payment of all ATM construction and installation costs by the ATM Provider, Murphy agrees to share equally with Wal-Mart in the construction and/ or installation cost of each ATM to be placed at an existing Station, up to a maximum amount of $2,500.00 per site ($1,250.00 net to Murphy), the balance of which is expected to be paid for by the ATM Provider.

c. Murphy will not pay any costs associated with the construction and/ or installation of an ATM at a new Station, as it is expected that-the ATM Provider will pay such costs. However, Murphy shall, during the construction of any new Station, perform all necessary site work for the ATM Property, including but not limited to, installing a line of conduit capable of supporting electrical service and other necessary cables, to the ATM. Property at the location shown on the final construction plans for the ATM, which is formally agreed to by both parties upon receipt of the construction start letter by Murphy. Wal-Mart shall use commercially reasonable efforts to cause the ATM provider to pay for these costs. If Wal-Mart-is unable to negotiate the payment of all ATM construction and installation costs by the ATM Provider, Murphy agrees to share equally with Wal-Mart in the construction and/or installation cost of each ATM to be placed at an existing Station, up to a maximum amount of $2,500.00 per site ($1,250.00 net to Murphy), the balance of which is expected to be paid for by the ATM Provider.

d. The ATM provider shall ensure payment of any and all utilities used upon the ATM Property from and after the date construction and/or installation of the ATM is completed. Murphy agrees that to the extent it is necessary for any utility connections to be located at the Station building, that such connections may be placed, at Murphy's reasonable discretion, in locations which do not interfere with Murphy's operations therein. The ATM provider shall be solely responsible for the cost of installing such connections, but Murphy agrees not to charge the ATM provider or Wal-Mart any fees for the location of such connections.

e. Wal-Mart shall indemnify and hold Murphy harmless against any loss, liability claim, damage, cost or expense arising out of or resulting from the construction, installation, or operation of the ATM's, or any activity that occurs on any ATM Property, except for any loss resulting from the negligence or intentional act of Murphy its employees, agents, or contractors.

f. At no time during the term or any extension of the Master Ground Lease for each Premises shall Murphy allow any lien to be attached to the ATM Property. In the event Murphy allows a lien to be imposed on the ATM Property it shall be considered an Event of Default for the purposes of this Amendment.

2.2 Modifications

If Wal-Mart, its agent, licensee, tenant or subtenant, wishes to make any material modifications to any ATM located on the Premises, Wal-Mart shall notify Murphy in writing of such material modifications, and obtain Murphy's approval of such material modifications, such approval shall not be unreasonably withheld or delayed. Routine equipment replacement, repair and maintenance shall not be considered a material modification. Murphy shall not be responsible for any costs or expense of such material modifications or any other modifications.

ARTICLE 3.
WAIVER OF RIGHTS

3.1 Waiver of Rights

Murphy hereby waives its rights pursuant to Article 3.2(a)(iv) of the Master Ground Lease to request Wal-Mart's approval to install ATM's on the Premises and such provision is hereby deleted. Wal-Mart shall have all such rights pursuant to the terms of this Amendment to construct and install ATM's on the Premises or assign such rights to an ATM provider.

ARTICLE 4.
RENT REDUCTION, PROFIT SHARING AND MONTHLY REPORTS

4.1 Rent Reduction

[Deleted]

4.2 Profit Sharing

[Deleted]

4.3 Monthly Reports

Not later than the fifteenth (15) day after Wal-Mart receives a. monthly income report from the ATM provider, Wal-Mart agrees to furnish Murphy a monthly report reflecting all income derived from the ATMs as referenced in Article 3. Murphy shall have the right to audit or cause to be audited such report at Murphy's expense within one (1) year after the end of the month which is the subject of the audit. If possible, all reports are to be sent to Murphy electronically. In the event that an electronic report cannot be generated, Wal-Mart agrees to send the reports to;

Murphy Oil USA, Inc.
Attn: Senior Vice President, Marketing
200 Peach Street, P.O. Box 7000
El Dorado, Arkansas 71730

4.4 Documentation

Upon request, Wal-Mart agrees to furnish to Murphy, from time to time, such information and backup documentation as may be reasonably requested by Murphy relating to the determination of Profit Sharing payments. Murphy shall reimburse Wal-Mart any cost associated with the production of such information and backup documentation.

ARTICLE 5.
INGRESS AND EGRESS

5.1 Ingress and Egress

Murphy and Wal-Mart shall at all times allow the other party, it's agents, suppliers and employees and its customers the right of ingress and egress to the ATM sufficient to conduct and encourage business. When the ATM is located on or within a fifty-foot radius of the Premises, Wal-Mart and Murphy shall use best efforts to route all traffic in a manner so as to minimize interference with Murphy and Wal-Mart's business.

ARTICLE 6.
MAINTENANCE, REPAIRS, AND CLEANLINESS

6.1 By Wal-Mart

a. Wal-Mart, its agent, licensee, tenant or subtenant, shall be responsible, at its cost and expense, for all repairs, maintenance and replacements for the ATM and the ATM Property, including but not limited to, the mechanical and electrical equipment and systems which comprise the ATM, and all other fixtures, appliances and facilities furnished or installed on the ATM Property by Wal-Mart, its agent, licensee, tenant or subtenant.

b. The ATM Property shall be kept in clean condition and appearance by Wal-Mart, its agent, licensee, tenant or subtenant, and shall be properly operating twenty-four (24) hours per day. (Subject to reasonable time for maintenance and repairs.)

ARTICLE 7.
LIABILITY INSURANCE

7.1 Liability Insurance

Wal-Mart agrees to obtain or cause the ATM provider to obtain and keep in force and effect at all times commercial general liability insurance with respect to the ATM and ATM

Property, with minimum limits of liability of two million dollars ($2,000,000) combined coverage per occurrence. Such insurance will name Murphy, its subsidiaries and affiliates, as additional insureds and will contain a provision that it is cancelable only upon not less than (30) days' notice in writing to Murphy. Upon request, Wal-Mart or the ATM provider agrees to provide Murphy copies of the declaration page(s) of the policy(ies) reflecting all of the foregoing. Wal-Mart or the ATM provider may self-insure the above coverage so long as Wal-Mart or the ATM provider maintains a net worth of or more. If requested, Wal-Mart will provide or cause the ATM provider to provide evidence of such insurance to Murphy within thirty (30) days after said request.

ARTICLE 8.
MISCELLANEOUS

8.1 Non-Fuel Rent

Murphy and Wal-Mart agree that any and all payments made by Wal-Mart to Murphy pursuant to this agreement shall not be considered "non-fuel sales and revenues" as referenced in Exhibit E of the Master Ground Lease. Therefore, Murphy does not owe Non-Fuel Rent of 3% on such ATM revenues.

ARTICLE 9.
INDEMNIFICATION

9.1 Indemnification of Murphy.

Wal-Mart shall indemnify Murphy, its directors, officers, agents, employees and owners to the extent of their interest in the Premises, and save them harmless from and against any and all losses, claims, actions, damages, liability, and expense, including, without limitation, reasonable attorneys' fees in connection with loss of life, personal injury, or damage to property arising from or out of any occurrence in, upon, or at the ATM Property, or the occupancy or use by Wal-Mart of the ATM Property or any part thereof, or occasioned wholly or in part by any act or omission of Wal-Mart, its agents, employees or contractors, except to the extent caused by the negligence of Murphy, its agents, employees or contractors.

ARTICLE 10.
ASSIGNMENT

10.1 By Wal-Mart

Wal-Mart may assign its rights or obligations under this Agreement to an affiliate or subsidiary without notice to Murphy. Any other assignment by Wal-Mart requires that thirty (30) days written notice be provided to Murphy. Wal-Mart agrees to remain liable for the obligations in Sections 4.1 and 4.2 regardless of any subsequent assignment.

ARTICLE 11.
DEFAULT

11.1 Default

If either party under this Amendment defaults or fails to perform its obligations herein, the non-defaulting party may give written notice to the defaulting party, and if such default is not cured within thirty (30) days of such written notice, either party may pursue all remedies available to it under applicable law or equity.

ARTICLE 12.
TAXES

12.1 Taxes

Both parties agree that Wal-Mart, its agent, licensee, tenant or subtenant shall make every effort to cause the ATM Property to be separately assessed for real property tax purposes. Wal-Mart, its agent, licensee, tenant or subtenant shall be responsible for the timely payment of all general and special real property taxes and assessments and all other government charges levied, assessed or imposed with respect to the ATM Property and all improvements constructed thereon and all assessments for local improvements, if any, attributable to the ATM Property. If the ATM Property cannot be separately assessed for real property tax purposes, Wal-Mart, its agent, licensee, tenant or subtenant shall pay that amount by which such real property taxes have increased by reason of improvements to the ATM Property. Wal-Mart, its agent, licensee, tenant or subtenant shall have the right to contest an assessment for and/or levy for any taxes which Wal-Mart, its agent, licensee, tenant or subtenant is obligated to pay under this article.

ARTICLE 13.
MUTUAL WAIVER OF SUBROGATION

13.1 Mutual Waiver Of Subrogation

Wal-Mart and Murphy each hereby releases the other and its respective employees, agents and every person claiming by, through or under either of them, from any and all liability or responsibility (to them or anyone claiming by, through or under them by way of subrogation or otherwise) for any loss or damage to any property (real or personal) caused by fire or any other insured peril covered by any insurance policies for the benefit of either party, even if such loss or damage shall have been caused by the fault or negligence of the other party, its employees or agents, or such other tenant or any employee or agent thereof.

Executed as of the date and year first above written.

MURPHY OIL USA, INC.	WAL-MART STORES, INC.
By: /s/	By: /s/
Title: SENIOR VICE-PRESIDENT, MARKETING	Title: Director, Wal-Mart Realty

THIRD AMENDMENT TO MOTOR VEHICLE FUELING STATING
MASTER GROUND LEASE AGREEMENT

THIS THIRD AMENDMENT TO MOTOR VEHICLE FUELING STATION MASTER GROUND LEASE AGREEMENT is made this the 1st day of August, 2002, by and between WAL-MART STORES, INC., a Delaware corporation of 702 S.W. 8th Street, Bentonville, Arkansas 72716 with offices at 2001 S.E, 10th Street, Bentonville, Arkansas 72716-0550 (Attn: Realty Management, No. 44-9384) (hereinafter referred to as "Lessor"), and MURPHY OIL USA, INC., a Delaware corporation, with offices at 200 Peach Street, El Dorado, Arkansas 71730 (hereinafter referred to as "Lessee").

WITNESSETH:

WHEREAS, the Lessor and Lessee have entered into a Motor Vehicle Fueling Station Master Ground Lease Agreement dated the 12th day of November, 1998, (hereinafter referred to as the "Master Ground Lease"), affecting certain Stations on one or more of the Premises or Outlets owned, leased or subleased by Lessor, as amended by that First Amendment to Motor Vehicle Fueling Station Master Ground Lease Agreement dated September 16, 1999, and that Second Amendment to Motor Vehicle Fueling Station Master Ground Lease Agreement dated August 15, 2001.

WHEREAS, Lessor and Lessee are now desirous of making certain amendments, changes and alterations to said Master Ground Lease to accurately reflect their intents and wishes.

NOW, THEREFORE, in consideration for One Dollar ($1.00) and other good and valuable considerations, including but not limited to the mutual covenants and agreements contained herein, the sufficiency of which is hereby acknowledged, with all capitalized terms having the same meaning as set forth in the Master Ground Lease and any amendments thereto, Lessor and Lessee hereby agree to amend Exhibit E of the Master Ground Lease as follows:

EXHIBIT E
(Page a of two pages)
RENT SCHEDULE "B"

[Deleted]

EXHIBIT E
(Page b of two pages)
RENT SCHEDULE "B"

IN WITNESS WHEREOF, the respective parties hereto have caused this amendment to be executed as of the date and year herein written above.

WAL-MART STORES, INC,
a Delaware corporation.

By: /s/

Title: Vice President Wal-Mart Realty

MURPHY OIL USA, INC,
a Delaware corporation.

By: /s/

Title: Sr. Vice President, Marketing

STATE OF ARKANSAS

COUNTY OF BENTON

I, as Notary Public in and for the County of Benton, State of Arkansas, certify that Anthony Fuller personally known to me to be the Vice President of W M Realty of WAL-MART STORES, INC., a Delaware corporation, came before me this day and acknowledged that he, by authority duly given and as the act of the corporation, signed the foregoing instrument in my presence.

Witness my hand and official stamp or seal, on this the 11 day of February, 2003.

/s/

Notary Public

My Commission Expires: [SEAL]

STATE OF ARKANSAS

COUNTY OF UNION

I, as Notary Public in and for the County of Union, State of Arkansas, certify that Charles Ganus personally known to me to be the Sr. V. Pres. Mkt. of MURPHY OIL USA, INC., a Delaware corporation, personally appeared before me this day and acknowledged that he, by authority duly given and as the act of the corporation, signed the foregoing instrument in my presence.

Witness my hand and official stamp or seal, on this the 27th day of January, 2003.

/s/

Notary Public

My Commission Expires: [SEAL]
7-6-09

Exhibit 12.1

Murphy Oil Corporation and Consolidated Subsidiaries
Computation of Ratio of Earnings to Fixed Charges (Unaudited)

(Thousands of Dollars)

	Year Ended December 31,				
	2002	2001	2000	1999	1998
Income (Loss) from Continuing Operations Before Income Taxes	$151,675	502,103	454,511	169,691	(12,774)
Distributions (Less Than) Greater Than Equity in Earnings of Affiliates	(3)	(365)	(34)	64	(15)
Previously Capitalized Interest Charged to Earnings During Period	7,748	3,450	3,507	3,146	2,172
Interest and Expense on Indebtedness	26,968	19,006	16,337	20,274	10,484
Interest Portion of Rentals (1)	9,445	7,953	5,808	3,267	3,293
Earnings Before Provision for Taxes and Fixed Charges	**$195,833**	**532,147**	**480,129**	**196,442**	**3,160**
Interest and Expense on Indebtedness, excluding capitalized interest	26,968	19,006	16,337	20,274	10,484
Capitalized Interest	24,536	20,283	13,599	7,865	7,606
Interest Portion of Rentals (1)	9,445	7,953	5,808	3,267	3,293
Total Fixed Charges	**$ 60,949**	**47,242**	**35,744**	**31,406**	**21,383**
Ratio of Earnings to Fixed Charges	**3.2**	**11.3**	**13.4**	**6.3**	— (2)

(1) Calculated as one-third of rentals. Considered a reasonable approximation of interest factor.
(2) The computation of earnings was less than fixed charges by $18,223 in 1998.

EXHIBIT 13

HIGHLIGHTS

FINANCIAL

(Thousands of dollars except per share data)		2002	2001	2000
FOR THE YEAR*				
Revenues	$	3,984,327	3,865,968	3,658,186
Net income		111,508	330,903	296,828
Cash dividends paid		70,898	67,826	65,294
Capital expenditures		868,100	864,440	557,897
Net cash provided by operating activities		532,844	635,704	747,751
Average Common shares outstanding - diluted		92,134,967	91,181,998	90,479,412
AT END OF YEAR				
Working capital	$	136,268	38,604	71,710
Net property, plant and equipment		2,886,599	2,525,807	2,184,719
Total assets		3,885,775	3,259,099	3,134,353
Long-term debt		862,808	520,785	524,759
Stockholders' equity		1,593,553	1,498,163	1,259,560
PER SHARE OF COMMON STOCK*				
Net income - diluted	$	1.21	3.63	3.28
Cash dividends paid		.775	.75	.725
Stockholders' equity		17.38	16.53	13.98

*Includes nonrecurring items that are detailed in Management's Discussion and Analysis, page 10 of the attached Form 10-K report.

OPERATING

FOR THE YEAR	2002	2001	2000
Net crude oil and gas liquids produced - barrels a day	76,370	67,355	65,259
United States	5,285	5,763	6,663
Canada	48,239	36,059	31,296
Other International	22,846	25,533	27,300
Net natural gas sold - thousands of cubic feet a day	296,931	281,235	229,412
United States	92,106	115,527	144,789
Canada	197,852	152,583	73,773
United Kingdom	6,973	13,125	10,850
Crude oil refined - barrels a day	143,829	167,199	165,820
North America	114,189	140,214	137,313
United Kingdom	29,640	26,985	28,507
Petroleum products sold - barrels a day	210,631	205,318	179,515
North America	176,427	174,256	149,612
United Kingdom	34,204	31,062	29,903

LETTER TO THE SHAREHOLDERS

[PICTURE APPEARS HERE]

DEAR FELLOW SHAREHOLDER:
Net income in 2002 was $111.5 million, $1.21 per share, compared to $330.9 million in 2001, $3.63 per share. The decline was principally due to lower crude oil and natural gas prices at the beginning of the year, depressed downstream results throughout the year and lower gains on asset dispositions. As a partial offset, the Company averaged 125,800 barrels equivalent a day of production in 2002, establishing a record which should be surpassed in 2003 and again in 2004.

Despite lower earnings, much was accomplished in 2002 that strengthens and enhances the future growth of your Company. The Terra Nova field (12%) came on stream in the first quarter with minimal start-up problems and produced above expectation all year. This field along with the nearby Hibernia field (6.5%) will be sources of net income and cash flow for many years to come. In addition, development work continued at Medusa (60%), Habanero (33.75%) and Front Runner (37.5%) in the deepwater Gulf of Mexico; West Patricia (85%) in shallow-water Malaysia; Syncrude (5%) in northern Alberta, Canada; and Block 16 (20%) in Ecuador. All of these fields, or field expansions, come on stream within the next few years (Medusa, Habanero, West Patricia and Block 16 in 2003) and will materially add to the profitability and size of Murphy.

Also during the year we continued the construction of the green fuels project at the Meraux refinery. This project will be completed in the third quarter of 2003 at which time the newly expanded refinery will exclusively manufacture both low-sulfur diesel and gasoline well in advance of government mandated deadlines. In the retail marketing arena, the Company's presence at Wal-Mart sites expanded as we built our 500th Murphy USA station in the fourth quarter of 2002. The build-out is ongoing with the 600th site expected to open early in the fourth quarter of this year. Murphy is the clear market leader in this segment, owning approximately one out of every four hypermarket fuel retailing outlets in America.

Perhaps the most significant event in 2002 was the Kikeh discovery in deepwater Block K (80%), offshore Malaysia. We followed up the discovery well, which was drilled at mid-year, with two appraisal wells that confirmed a substantial new field. The Company

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now holds a substantial acreage position in the Sabah Trough - a virtually undrilled geological province with only 13 wells that have yielded seven discoveries. We will drill a minimum of five wildcats in deepwater Malaysia in 2003 as we systematically set about exploring this massive and extremely prospective acreage position.

We are taking advantage of the current frothy price environment to dispose of high-cost fields that no longer contribute to our portfolio. It is not without a touch of sadness that we sold the venerable Ship Shoal Block 113 unit (50-70%) in the Gulf of Mexico in 2002 and in early 2003 signed a letter of intent to sell the once super-giant Ninian field (13.82%) in the U.K. North Sea. Each field marked a milestone in the growth of your Company and were important sources of cash flow through some of the lean times in the 1980s. Cash lifting costs for these fields were in excess of $8.00 a barrel in 2002; it was clearly time to let them go. Importantly, new fields will more than replace this production and cash flow.

We suffered some setbacks in 2002. Except for Kikeh, our explorers did not perform at their same outstanding level of the past several years, and for the first time in 12 years we did not replace our production. Given the frontier nature of your Company's exploratory program, this type of annual result is perhaps, at some point, unavoidable. Also, given the size and extent of our interest in the Sabah Trough, the events that occurred in 2002 should provide extraordinary impetus for future reserve growth. In addition, the Company's downstream business was bedeviled by weak refining and marketing margins much of the year exacerbated by poor ontime performance for the Meraux refinery. Returning to a more efficient operation at Meraux is a priority for 2003.

I am extremely sanguine regarding Murphy Oil Corporation's future. Your Company has a powerful combination of high-quality, low-cost producing fields that form the current core, soon to be augmented by the lineup of new production that comes on stream in

[GRAPHIC APPEARS HERE]

2003 and 2004. Furthermore, our exploration potential is as good as I have ever seen at Murphy. The Company's deepwater Gulf of Mexico 2003 prospect listing is outstanding, with up to six wildcats on tap. The portfolio in deepwater Malaysia is extensive in both quality and number. We have excellent opportunities for meaningful reserve additions this year in these programs. The Company's downstream business, anchored by our stations at Wal-Mart stores, is rapidly expanding its market share at the expense of less efficient competitors.

The Board of Directors signaled strong support for the future growth of the Company by increasing the dividend to $.80 a share (on a post-split basis) at mid-year. In addition, the Board split the stock two-for-one at the end of the year. The Board also added two extremely capable new members in February of 2003. Frank Blue, a lawyer who is Of Counsel with the firm of Fulbright & Jaworski, specializes in corporate governance. Frank was most recently Vice-President, General Counsel and Corporate Secretary with Caltex Corporation, one of the largest oil and gas firms operating in the Far East. Ivar Ramberg was most recently President and CEO of Norsk Hydro Canada. Before joining the industry, he had a distinguished university academic career in Norway and the U.S. teaching geology and geophysics.

Enoch Dawkins, President of Murphy Exploration & Production Company, will retire on March 1, 2003, and Herb Fox, Executive Vice President of Worldwide Downstream, will retire on April 1, 2003. Upon retirement, Enoch and Herb will have 39 and 33 years of service, respectively, with your Company. Each provided invaluable contributions to their respective disciplines and important assistance to the Company's broader goals. They are men of integrity and dedication and always put in the time required to get the job done. They will be missed.

Charles H. Murphy, Jr. died March 20, 2002. He was a unique man with extraordinary insights not only into our industry but also the larger world. He inspired at least two generations of Murphy managers who were fortunate enough to work with him. Also, George Ishiyama died February 4, 2003. George was a director from 1976 to 1986 and a director emeritus from 1986 to 2003. He was a pioneer in promoting post-war, U.S.-Japanese trade development and a valued contributor to the Board.

As always, I appreciate your support and look forward with confidence to our shared future.

/s/ Claiborne P. Deming

Claiborne P. Deming
President and Chief Executive Officer

February 19, 2003
El Dorado, Arkansas

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EXPLORATION & PRODUCTION

Murphy continues to generate significant production growth through its focused exploration programs in deepwater Gulf of Mexico, offshore eastern Canada, western Canada and Malaysia.

For the full year 2002, worldwide production averaged more than 125,800 barrels of oil equivalent a day, which reflected an increase of 10% over 2001 average levels, and continued Murphy's trend of achieving higher production levels each year for the last three years. Driving the increase was the start-up of production at the Terra Nova field offshore eastern Canada and peaking natural gas production rates at the Murphy-operated Ladyfern field in western Canada. The trend of increased production is set to continue in 2003, as two new fields in the deepwater Gulf of Mexico, Medusa and Habanero, come on stream and production in shallow-water Malaysia commences. Production rates during 2003 should reach an average of 130,000 to 135,000 barrels of oil equivalent a day. Operations during 2004 will benefit from a full year of Medusa, Habanero and shallow-water Malaysia production. Also in 2004, the Murphy-operated Front Runner field will be placed on stream, which should drive Murphy's average oil equivalent production on a worldwide basis above 160,000 barrels a day.

The deepwater Gulf of Mexico remains an integral component of

EXPLORATION AND PRODUCTION

(thousands of dollars)	2002	2001	2000
Income from continuing operations	$ 161,003	187,543	245,755
Total assets	2,387,381	2,151,049	1,902,618
Capital expenditures	632,250	683,448	392,732
Crude oil and liquids produced - barrels a day	76,370	67,355	65,259
Natural gas sold - MCF a day	296,931	281,235	229,412
Net hydrocarbons produced - oil equivalent barrels a day	125,859	114,228	103,494
Net proved hydrocarbon reserves - thousands of oil equivalent barrels	455,300	501,200	442,300

Murphy's upstream strategy. Murphy moved to the deepwater in 1996 and to date has accumulated an acreage position of 154 blocks and has three major discoveries in development. Two of these developments, Medusa and Habanero, will be placed on stream during 2003. The first deepwater development is in the final stages at the Murphy-operated Medusa field in Mississippi Canyon Blocks 538 and 582 (60%) as the hull is on site and is expected to be mated with the topsides in early spring. The Medusa facility is sized to handle daily production rates of up to 40,000 barrels of oil and 110 million cubic feet of natural gas. First production is anticipated for mid-year 2003 and will ramp up throughout the remainder of the year.

The Habanero field, located in Garden Banks Block 341 (33.75%), is the other deepwater Gulf of Mexico development nearing completion and first production is expected during the third quarter of 2003 when two wells in this field will be tied into an existing host facility.

The Front Runner project, located in Green Canyon Blocks 338/339, was sanctioned in early 2002 with first production expected in 2004. The development plan includes a Truss Spar-type Floating Production System capable of handling daily production of 60,000 barrels of crude oil and 110 million cubic feet of natural gas and will serve as a production hub for Murphy-operated discoveries at Front Runner, Front Runner South and Quatrain (all 37.5%). Front Runner and Front Runner South were discovered during 2001. A smaller discovery was drilled at Quatrain during the third quarter of 2002. The well at Quatrain was cased as a producing well to tie into the spar facility being constructed for the Front Runner project. Located only one mile from the planned location of the Front Runner spar, Quatrain will be a cost effective tie back to that facility and reflects the maturity of Murphy's deepwater drilling program, whereby smaller discoveries can be economically produced through Company-owned and operated facilities.

Exploratory drilling will continue in the immediate Front Runner area, as Murphy plans to test at least two prospects during 2003 on the 13 contiguous blocks currently under lease by the Company. The first of which, Cool Papa, located in Green Canyon Block 380 (37.5%), is set to spud early in the second quarter of 2003. A wildcat well at the Lecomte

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prospect, located in Green Canyon Block 428 (37.5%), is also planned for 2003. Murphy has identified several other prospects on this group of blocks and is planning further drilling in this region in 2004. In addition, a well will be drilled in the second quarter of 2003 to test a prospect named RunfortheRoses, located approximately 27 miles south of the Front Runner area in Green Canyon Blocks 735 and 736 (50%).

Off the east coast of Canada, the Terra Nova field (12%) was placed on stream in January 2002. Terra Nova produces through a state-of-the-art floating storage and production facility and serves as a strong complement to the nearby Hibernia field (6.5%). The production ramp-up from the Terra Nova field was outstanding and, based on high volume testing of the facility, the operator has applied for increases in allowable throughputs. Similarly, Hibernia produced at record volumes in 2002 and is seeking increased allowable production rates. These East Coast assets were a primary driver of Murphy's strong production increases during 2002 and are on track for record volumes again in 2003.

The results of Murphy's first three exploration wells on the Scotian Shelf, near Sable Island, were disappointing. In August 2002, Murphy and partners announced results from Annapolis (19%), the first industry deepwater well drilled off the Scotian Shelf. This well proved the existence of reservoir and hydrocarbon presence in a wildcat setting, but further drilling is required to establish threshold reserves for a commercial development. To this end, Murphy and partners are discussing additional exploratory drilling on the Annapolis block during 2003. Seismic surveys will also be acquired over the two adjacent blocks. This area has the potential to add North American natural gas reserves to Murphy's oil-weighted portfolio.

In western Canada, natural gas production reached record rates propelled by Murphy's operated interest in the prolific Ladyfern field (63%). The field reached peak gross production rates of over 700 million cubic feet a day as expected during the early summer of 2002 and is currently in decline. The Company continues to explore its large acreage position west of Ladyfern, and is also active with several winter wells in the foothills.

Murphy continues to be a player in the heavy oil and oil sands industry in Canada. An aggressive heavy oil drilling program began before year-end 2002, and will continue into 2003, focusing on primary and secondary recovery of conventional heavy oils in Murphy's traditional operating areas. Strong production growth from these properties is anticipated during 2003. Murphy is also an owner in Syncrude (5%), which has undertaken an aggressive expansion and will contribute growing volumes.

The Company believes it is important to continue to participate in the development of this vast Canadian resource, which offers a secure supply of hydrocarbons in North America for future decades.

The most significant story of 2002 on the exploration front lies in deepwater Malaysia. After a rocky beginning, with announced dry holes at the Bagang and Bliais prospects, Murphy achieved success at Kikeh (80%), the first deepwater oil discovery made in Malaysia. The initial Kikeh well in the southern part of Block K in 4,400 feet of water found in excess of 500 net feet of oil pay and Murphy quickly moved to drill more wells to appraise the size of the structure. A total of three wells and two associated sidetracks have been drilled with an average net oil pay of 400 to 600 feet. Furthermore, all pay sands appeared to be in communication and were full to base with oil. To date, no water or natural gas has been found in any of the wells. During 2003, a different well location on the Kikeh structure will be drilled, then production tested, to help further define both reserves

[GRAPH APPEARS HERE]

[PICTURE APPEARS HERE]

and oil flow characteristics. Following those results, an engineering and design study will commence to determine the type of development needed with the aim of sanctioning a development project by year-end 2003 or early 2004. First production from deepwater Malaysia is expected by 2007.

Murphy will also test at least two new prospects on Block K this year and one on undrilled contiguous Block H to further explore Murphy's large deepwater Malaysia acreage position. Each of these prospects, if successful, have the potential to materially affect the reserves of the Company. Although exact drilling locations have not been named, drilling on Block K will likely be concentrated in the Kikeh vicinity searching for Kikeh "look-alikes," and on the southwest corner of Block H near exploratory success by another company in an adjacent block. Murphy, as operator, has an 80% working interest in Block K and adjoining Block H, which combined, cover over six million acres.

Success continues in Murphy's 85%-owned, shallow-water blocks in Malaysia. During 2002, Murphy confirmed the commercial viability of this acreage, by sanctioning a development at West Patricia, located approximately 25 miles from the coastal port of Bintulu, Sarawak, Malaysia. The establishment of a production center will allow Murphy to fully develop its surrounding acreage. Development at West Patricia is proceeding and the field is scheduled to be placed on stream during the second quarter of 2003. West Patricia will produce from a well jacket to a floating storage facility and will net to the Company approximately 10,000 barrels a day of oil at peak rates. West Patricia has been designed as a production hub

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and Murphy has identified many nearby untested structures that, if successful, could tie into the West Patricia infrastructure. In fact, Murphy has already had success at the nearby Congkak discovery. With the Congkak #1 exploration well, Murphy discovered a new oil field in Block SK 309, offshore Sarawak. The Congkak discovery is located in 136 feet of water and lies three kilometers from the West Patricia field production platform. The discovery supports Murphy's belief that there are many small field development opportunities on the acreage and the Company views Congkak as a natural add-on to its established infrastructure.

Murphy continues to extend its presence in Malaysia with the addition of an acreage position in Peninsular Malaysia and a new award of acreage in deepwater. A production sharing contract was signed in July 2002 giving Murphy a 75% working interest in PM Blocks 311/312. These blocks represent exploitation acreage, similar to shallow-water Blocks SK 309/311, as hydrocarbons have already been found on the blocks. Murphy plans to shoot 3D seismic surveys during 2003 in preparation for a drilling program that will commence in 2004.

[PICTURE APPEARS HERE]

REFINING & MARKETING

In Murphy's downstream operations, refining and marketing margins in the U.S. and U.K. were squeezed during 2002 primarily due to generally rising crude oil prices throughout the year. Results were also hampered during the year by operational problems at the Meraux refinery that reduced the average daily crude oil throughput of this plant. The downstream business incurred a loss of almost $40 million in 2002 following a year of record operating earnings in 2001.

The Murphy USA program continues to be the focus for the Company's downstream operation. In cooperation with Wal-Mart, Murphy builds high volume fueling sites in the parking lots of Wal-Mart Supercenters throughout the southern and midwestern United States. Through these outlets, Murphy provides gasoline and diesel to customers with convenient service and significant cost savings. Sales volumes at Murphy USA stations remain strong, averaging over 200,000 gallons a month per site. The Company opened its 500th location late in 2002 in Houston, Texas and by year-end had 506 sites in operation. These sites combine the benefits of low operating costs, low capital costs and high sales volume to create a formidable retail presence.

Of note in 2002, Murphy signed a new agreement with Wal-Mart to extend this program in Canada. Marketed under the Murphy Canada brand, six sites are currently open.

Due to the growth of the Murphy USA retail marketing business, the Company must buy a larger portion of gasoline needed to supply these stations. The size of this business has allowed the Company to achieve a stronger negotiating position for gasoline purchases in its marketing areas.

The expansion project at the Meraux refinery continued to proceed during

REFINING AND MARKETING

(thousands of dollars)	2002	2001	2000
Income (loss)	$ (39,908)	153,680	54,456
Total assets	1,208,244	918,764	1,018,555
Capital expenditures	234,714	175,186	153,750
Crude oil processed - barrels a day	143,829	167,199	165,820
Products sold - barrels a day	210,631	205,318	179,515

[GRAPH APPEARS HERE]

2002. Murphy is constructing a hydrocracker and related hardware that, when installed, will allow Murphy to produce low-sulfur gasoline and diesel products ahead of mandated requirements. The Company is also expanding the refinery's crude processing capacity from 100,000 to 125,000 barrels a day. The start-up of the hydrocracker and expanded crude unit is expected to take place during the third quarter of 2003. Once this green fuels project is completed, capital expenditures in the Company's downstream business will sharply drop.

Murphy also owns a refinery at Superior, Wisconsin, on the western tip of Lake Superior. This refinery can process 35,000 barrels per day of Canadian and domestic crude oil, with its primary attribute being the ability to produce asphalt products from generally lower-priced Canadian heavy oil that is available to the refinery via pipeline. Superior's lighter refined products also serve to supply the Company's stations at Wal-Mart stores in the upper Midwest.

Murphy has an effective 30% interest in a refinery at Milford Haven, Wales, where up to 32,400 barrels of crude oil per day can be processed for the Company's account. The Company markets light refined products to U.K. retail customers primarily under the Murco brand. Murphy's U.K. downstream business continues to benefit from a successful alliance with the Costcutter grocery chain, which upgrades neighborhood motor fueling stations into popular and convenient shopping destinations for local consumers.

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As a mid-size player in the energy industry, Murphy realizes it must deploy resources in a focused, deliberate manner. To this end, Murphy concentrates its exploration capital in four main areas: deepwater Gulf of Mexico, western Canada, the Scotian Shelf offshore eastern Canada, and Malaysia. To date, Murphy has announced significant discoveries in three of its core areas through success at Medusa and Front Runner in the deepwater Gulf, the Ladyfern natural gas field in western Canada and Kikeh in deepwater Malaysia.

Murphy has substantially increased its production profile and added value to the Company by meticulously concentrating on what it does best -adding reserves through the drill bit. In downstream operations, Murphy has a retail presence through its relationship with Wal-Mart that is unparalleled in the industry. The combination of its acreage portfolio, aggressive exploration program, and downstream retail strategy position Murphy as an outperformer not only capable of continuing its successful track record, but ready to climb to a new level of growth and profitability.

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STATISTICAL SUMMARY

	2002	2001	2000	1999	1998
EXPLORATION AND PRODUCTION					
Net crude oil and condensate production - barrels a day					
United States	3,837	4,339	4,770	5,826	5,192
Canada - light	2,150	2,937	2,606	2,992	3,219
heavy	9,484	11,707	10,574	9,099	9,676
offshore	24,037	9,535	9,199	6,404	4,192
synthetic	11,362	10,479	8,443	10,997	10,500
United Kingdom	18,180	20,049	20,679	20,217	14,975
Ecuador	4,544	5,319	6,405	7,104	7,720
Net natural gas liquids production - barrels a day					
United States	291	413	551	777	643
Canada	1,206	1,401	474	488	612
United Kingdom	122	165	216	321	436
Continuing operations	75,213	66,344	63,917	64,225	57,165
Discontinued operations	1,157	1,011	1,342	1,858	1,963
Total liquids produced	76,370	67,355	65,259	66,083	59,128
Net crude oil and condensate sold - barrels a day					
United States	3,837	4,339	4,769	5,832	5,185
Canada - light	2,150	2,937	2,606	2,992	3,219
heavy	9,484	11,707	10,574	9,099	9,676
offshore	23,935	9,862	9,456	4,727	4,396
synthetic	11,362	10,479	8,443	10,997	10,500
United Kingdom	18,209	20,206	20,921	20,217	15,336
Ecuador	4,293	5,381	6,393	7,104	7,907
Net natural gas liquids sold - barrels a day					
United States	291	413	551	777	643
Canada	1,206	1,401	474	488	612
United Kingdom	149	148	216	321	436
Continuing operations	74,916	66,873	64,403	62,554	57,910
Discontinued operations	1,157	1,011	1,342	1,858	1,963
Total liquids sold	76,073	67,884	65,745	64,412	59,873
Net natural gas sold - thousands of cubic feet a day					
United States	88,067	112,616	141,373	163,587	160,932
Canada	197,852	152,583	73,773	56,238	48,998
United Kingdom	6,973	13,125	10,850	12,443	12,384
Continuing operations	292,892	278,324	225,996	232,268	222,314
Discontinued operations	4,039	2,911	3,416	8,175	8,587
Total natural gas sold	296,931	281,235	229,412	240,443	230,901
Net hydrocarbons produced - equivalent barrels/1/,/2/ a day	125,859	114,228	103,494	106,157	97,612
Estimated net hydrocarbon reserves - million equivalent barrels/1/, /2/,/3/	455.3	501.2	442.3	400.8	379.9
Weighted average sales prices/4/					
Crude oil and condensate - dollars a barrel					
United States	$ 24.25	24.92	30.38	18.09	12.89
Canada/5/ - light	22.60	22.40	27.68	17.00	12.03
heavy	16.82	11.06	17.83	12.77	6.56
offshore	25.36	23.77	27.16	19.08	11.80
synthetic	25.64	25.04	29.62	18.64	13.73
United Kingdom	24.39	24.44	27.78	18.09	12.52
Ecuador	19.64	17.00	22.01	14.42	8.56
Natural gas liquids - dollars a barrel					
United States	17.13	20.40	23.04	13.70	11.50
Canada/5/	16.35	20.35	19.98	12.09	9.16
United Kingdom	18.28	19.12	23.64	13.45	11.04
Natural gas - dollars a thousand cubic feet					
United States	3.37	4.64	4.01	2.34	2.25
Canada/5/	2.74	3.28	3.67	1.96	1.40
United Kingdom/5/	2.76	2.52	1.81	1.68	2.23

/1/ Natural gas converted at a 6:1 ratio.
/2/ Includes synthetic oil.
/3/ At December 31.
/4/ Includes intracompany transfers at market prices.
/5/ U.S.dollar equivalent.

STATISTICAL SUMMARY

	2002	2001	2000	1999	1998
REFINING					
Crude capacity/1/ of refineries - barrels per stream day	167,400	167,400	167,400	167,400	167,400
Refinery inputs - barrels a day					
Crude - Meraux, Louisiana	83,721	104,345	103,154	82,410	101,834
Superior, Wisconsin	30,468	35,869	34,159	33,402	32,966
Milford Haven, Wales	29,640	26,985	28,507	27,392	30,780
Other feedstocks	11,013	9,901	8,298	10,484	11,404
Total inputs	154,842	177,100	174,118	153,688	176,984
Refinery yields - barrels a day					
Gasoline	63,409	73,217	75,106	65,216	73,482
Kerosine	9,446	12,874	11,955	11,316	15,394
Diesel and home heating oils	48,344	52,660	49,606	44,054	50,506
Residuals	16,589	20,530	18,524	17,370	21,310
Asphalt, LPG and other	12,651	13,467	14,624	12,225	12,565
Fuel and loss	4,403	4,352	4,303	3,507	3,727
Total yields	154,842	177,100	174,118	153,688	176,984
Average cost of crude inputs to refineries - dollars a barrel					
North America	$ 24.76	23.44	28.82	18.80	12.55
United Kingdom	25.83	24.86	29.29	17.22	13.62
MARKETING					
Products sold - barrels a day					
North America - Gasoline	112,281	96,597	76,314	61,786	61,429
Kerosine	5,818	9,621	8,517	7,545	10,170
Diesel and home heating oils	35,995	41,064	39,347	34,514	40,403
Residuals	13,759	17,308	15,163	13,812	16,170
Asphalt, LPG and other	8,574	9,666	10,271	9,134	9,887
	176,427	174,256	149,612	126,791	138,059
United Kingdom - Gasoline	12,058	11,058	11,622	12,511	14,058
Kerosine	2,685	2,547	2,478	3,053	4,369
Diesel and home heating oils	14,574	11,798	9,760	10,995	10,884
Residuals	3,127	3,538	3,852	3,608	5,203
LPG and other	1,760	2,121	2,191	2,084	1,579
	34,204	31,062	29,903	32,251	36,093
Total products sold	210,631	205,318	179,515	159,042	174,152
Branded retail outlets/1/					
North America	914	815	712	625	552
United Kingdom	416	411	386	384	389
STOCKHOLDER AND EMPLOYEE DATA					
Common shares outstanding/1/,/2/ (thousands)	91,689	90,662	90,092	89,996	89,900
Number of stockholders of record/1/	2,826	2,991	3,185	3,431	3,684
Number of employees/1/	4,010	3,779	3,109	2,153	1,566
Average number of employees	3,875	3,438	2,528	1,797	1,498

/1/ At December 31.
/2/ 1998 through 2001 have been adjusted to reflect a two-for-one stock split effective December 30, 2002.

.. DIRECTORS

WILLIAM C. NOLAN JR. /1/
Chairman of the Board
Murphy Oil Corporation
Partner
Nolan and Alderson
El Dorado, Arkansas
Director since 1977

CLAIBORNE P. DEMING /1/
President and Chief Executive Officer
Murphy Oil Corporation
El Dorado, Arkansas
Director since 1993

FRANK W. BLUE /2/,/4/
Attorney
Fulbright & Jaworski
Houston, Texas
Director since 2003

GEORGE S. DEMBROSKI /1/,/2/,/3/
Vice Chairman, Retired
RBC Dominion Securities Limited
Toronto, Ontario, Canada
Director since 1995

H. RODES HART /2/,/3/
Chairman and Chief Executive Officer
Franklin Industries, Inc.
Nashville, Tennessee
Director since 1975

ROBERT A. HERMES /4/,/5/
Chairman of the Board
Purvin & Gertz, Inc.
Houston, Texas
Director since 1999

MICHAEL W. MURPHY
President
Marmik Oil Company
El Dorado, Arkansas
Director since 1977

R. MADISON MURPHY /1/,/2/
Private Investor
El Dorado, Arkansas
Director since 1993

IVAR B. RAMBERG /4/,/5/
Executive Officer
Ramberg Consulting AS (Ram-Co)
Lysaker, Norway
Director since 2003

DAVID J. H. SMITH /3/,/5/
Chief Executive Officer, Retired
Whatman plc
Maidstone, Kent, England
Director since 2001

CAROLINE G. THEUS /1/,/5/
President
Keller Enterprises, LLC
Alexandria, Louisiana
Director since 1985

.. EXECUTIVE OFFICERS

CLAIBORNE P. DEMING
President and Chief Executive Officer

W. MICHAEL HULSE
Executive Vice President - Worldwide
Downstream Operations

STEVEN A. COSSE
Senior Vice President and
General Counsel

BILL H. STOBAUGH
Vice President

KEVIN G. FITZGERALD
Treasurer

JOHN W. ECKART
Controller

WALTER K. COMPTON
Secretary

.. DIRECTOR EMERITUS

William C. Nolan

- ----------
COMMITTEES OF THE BOARD

/1/ Member of the Executive Committee chaired by Mr. Nolan. The Chairman serves as ex-officio member of all Committees.

/2/ Member of the Audit Committee chaired by Mr. R. Madison Murphy.

/3/ Member of the Executive Compensation Committee chaired by Mr. Dembroski.

/4/ Member of the Nominating and Governance Committee chaired by Mr. Hermes.

/5/ Member of the Public Policy and Environmental Committee chaired by Mrs. Theus.

.. PRINCIPAL SUBSIDIARIES

Murphy Exploration &
Production Company - USA

131 South Robertson Street
New Orleans, Louisiana 70112
(504) 561-2811

Mailing Address:
P. O. Box 61780
New Orleans, Louisiana 70161-1780

Engaged in crude oil and
natural gas exploration and production
in the continental U.S. and in the
Gulf of Mexico.

JOHN C. HIGGINS
President

S. J. CARBONI JR.
Vice President, Deepwater
Development and Production

JAMES R. MURPHY
Vice President, Exploration

STEVEN A. COSSE
Vice President and General Counsel

KEVIN G. FITZGERALD
Treasurer

GASPER F. BIVALACQUA
Controller

WALTER K. COMPTON
Secretary

Murphy Oil Company Ltd.

2100-555-4th Avenue S.W.
Calgary, Alberta T2P 3E7
(403) 294-8000

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

Engaged in crude oil and natural
gas exploration and production,
extraction and sale of synthetic crude
oil, and marketing of petroleum
products in Canada.

HARVEY DOERR
President

TIMOTHY A. LARSON
Vice President, Crude Oil and
Natural Gas

J. TERRY MCCOY
Vice President, Exploration
and Land

W. PATRICK OLSON
Vice President, Production

ROBERT L. LINDSEY
Vice President, Finance
and Secretary

KEVIN G. FITZGERALD
Treasurer

Murphy Exploration & Production
Company - International

550 WestLake Park Blvd.
Suite 1000
Houston, Texas 77079
(281) 249-1040

Engaged in crude oil and
natural gas exploration and
production outside North
America and in Alaska.

DAVID M. WOOD
President

GEORGE M. SHIRLEY
Vice President and General

Manager - Malaysia

STEVEN A. COSSE
Vice President and General Counsel

KEVIN G. FITZGERALD
Treasurer

JOHN W. ECKART
Controller

WALTER K. COMPTON
Secretary

Murphy Oil USA, Inc.

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

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

Engaged in refining and marketing of petroleum products in the United States.

W. MICHAEL HULSE
President

CHARLES A. GANUS
Senior Vice President, Marketing

FREDEREC C. GREEN
Senior Vice President,
Engineering and Government Affairs

GARY R. BATES
Vice President, Supply and
Transportation

HENRY J. HEITHAUS
Vice President, Retail Marketing

ERNEST C. CAGLE
Vice President, Manufacturing

STEVEN A. COSSE
Vice President and General Counsel

GORDON W. WILLIAMSON
Treasurer

JOHN W. ECKART
Controller

WALTER K. COMPTON
Secretary

MURPHY EASTERN OIL COMPANY

4 Beaconsfield Road
St. Albans, Hertfordshire
AL1 3RH, England
172-789-2400

Provides technical and professional services to certain of Murphy Oil Corporation's subsidiaries engaged in crude oil and natural gas exploration and production in the Eastern Hemisphere and refining and marketing of petroleum products in the United Kingdom.

STEPHEN R. WYLIE
President

KEVIN W. MELNYK
Vice President, Supply and Refining

IJAZ IQBAL
Vice President

KEVIN G. FITZGERALD
Treasurer

WALTER K. COMPTON
Secretary

PRINCIPAL OFFICES

- El Dorado, Arkansas
- New Orleans, Louisiana
- Houston, Texas
- Calgary, Alberta, Canada
- St. Albans, Hertfordshire, England
- Kuala Lumpur, Malaysia

.. Corporate Information

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El Dorado, Arkansas 71731-7000
(870) 862-6411

STOCK EXCHANGE LISTINGS
Trading Symbol: MUR
New York Stock Exchange
Toronto Stock Exchange

TRANSFER AGENTS
Computershare Investor Services, L.L.C.
P. O. Box A3504
Chicago, Illinois 60690-3504
Toll-free (888) 239-5303
Local Chicago (312)360-5303

COMPUTERSHARE TRUST COMPANY OF CANADA
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Toronto, Ontario M5J 2Y1

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P. O. Box A3504
Chicago, Illinois 60690-3504

E-MAIL ADDRESS
murphyoil@murphyoilcorp.com

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

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

ANNUAL MEETING
The annual meeting of the Company's shareholders will be held at 10 a.m. on May 14, 2003, at the South Arkansas Arts Center, 110 East 5th Street, El Dorado, Arkansas. A formal notice of the meeting, together with a proxy statement and proxy form, will be mailed to all shareholders.

INQUIRIES
Inquiries regarding shareholder account matters should be addressed to:

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

Members of the financial community should direct their inquiries to:

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

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

Computershare Investor Services, L.L.C.
P. O. Box 0289
Chicago, Illinois 60690-0289
Toll-free (888) 239-5303
Local Chicago (312) 360-5303

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MURPHY OIL CORPORATION – CIK 0000717423

Appendix to Electronically Filed Exhibit 13
(2002 Annual Report to Security Holders, Which is Incorporated in This Form 10-K Report)
Providing a Narrative of Graphic and Image Material Appearing on
Pages 1 Through 12 of Paper Format

Exhibit 13 Page No.	Picture Narrative
1	Claiborne P. Deming, President and Chief Executive Officer of Murphy Oil Corporation, is pictured. Perhaps the most significant event in 2002 was the Kikeh discovery in deepwater Block K (80%), offshore Malaysia. Murphy now holds a substantial acreage position in the Sabah Trough – a virtually undrilled geological province with only 13 wells that have yielded seven discoveries.
3	In November 2002, Murphy opened its 500th Murphy USA retail fueling outlet in Houston, Texas; a Murphy USA station is shown.
5	The oil tanker Kometik shuttles production from Murphy's Hibernia and Terra Nova fields, with the latter field being the primary driver of the Company's production increase in 2002; a photo of the vessel is displayed.
7	A semisubmersible rig is shown drilling the Kikeh discovery, the first in deepwater Malaysia believed to be one of the most significant discoveries in Company history.
9	Six development wells were drilled from this well jacket at West Patricia in preparation for first oil production in 2003; a photo of a portion of the well jacket is presented.
11	The Meraux refinery's clean fuels project includes the addition of a hydrocracker unit, which will help Murphy provide "greener" fuels to consumers; a photo of the construction site is displayed.
Map	Map Narrative

Murphy has secured strategic worldwide positions for oil and gas exploration and production and downstream operations. A world map is displayed with a key indicating the Company's Properties, Headquarters, Refineries, and Other Principal offices. A brief narrative of certain properties is displayed within the map as follows:

> Syncrude – Murphy has a five-percent ownership interest in Syncrude Canada, Ltd., the largest single oil producing operation in Canada. Stage III expansion will raise the gross production from this operation to 335,000 barrels per day by 2005.
>
> Hibernia & Terra Nova – These two large fields are the first to come on-line offshore Newfoundland. On a combined basis, these fields produced 24,000 barrels of oil per day net to Murphy's interest in 2002.

Exhibit 13 Page No.	Picture Narrative(Contd.)
Map (Contd.)	

Gulf of Mexico Deepwater – The Company has accumulated 154 blocks in the deep waters of the Gulf of Mexico. To date Murphy has four discoveries, three of which will be on stream in 2003 and 2004.

Meraux Refinery – Major expansion projects will be completed in 2003 and will enable the refinery to meet new low sulfur product specifications which will be mandatory in 2006.

Murphy USA Sites – Murphy had 506 operating retail stations at Wal-Mart sites in the U.S. at December 31, 2002. The Company will build another 100 stations in 2003.

Ecuador – A new heavy oil pipeline will be operational in the second half of 2003 that will allow the Company's production from Block 16 to double to about 11,000 barrels per day.

Malaysia – New production will commence in mid-2003 from shallow-water Block SK 309. The Company made a sizeable discovery at Kikeh in deepwater Block K in 2002. Significant exploration work will continue on deepwater blocks in 2003.

Exhibit 13 Page No.	Graph Narrative(Contd.)	1998	1999	2000	2001	2002
1	NET HYDROCARBONS PRODUCED					
	Scale 0 to 150 (thousands of oil equivalent barrels a day)					
	Ecuador and Other (top)	8	7	6	5	4
	United Kingdom	18	23	23	22	20
	Canada	36	39	43	62	81
	United States (bottom)	36	37	31	25	21
	Total	98	106	103	114	126
	This stacked vertical bar graph has the total for each bar printed above it.					
2	CAPITAL EXPENDITURES BY FUNCTION					
	Scale 0 to 900 (millions of dollars)					
	Corporate (top)	2	3	11	6	1
	Refining and Marketing	55	88	154	175	235
	Exploration and Production (bottom)	332	296	393	683	632
	Total	389	387	558	864	868
	This stacked vertical bar graph has the total for each bar printed above it.					
7	ESTIMATED NET PROVED HYDROCARBON RESERVES					
	Scale 0 to 600 (millions of oil equivalent barrels)					
	Ecuador and Other (top)	32	37	41	54	48
	United Kingdom	63	63	56	50	48
	Canada	188	195	238	243	234
	United States (bottom)	97	106	107	154	125
	Total	380	401	442	501	455
	This stacked vertical bar graph has the total for each bar printed above it.					
8	CAPITAL EXPENDITURES – EXPLORATION AND PRODUCTION					
	Scale 0 to 720 (millions of dollars)					
	United Kingdom and Other (top)	103	41	46	32	55
	Malaysia	—	3	18	45	127
	Canada	108	156	192	347	228
	United States (bottom)	121	96	137	259	222
	Total	332	296	393	683	632
	This stacked vertical bar graph has the total for each bar printed above it.					
11	REFINED PRODUCTS SOLD					
	Scale 0 to 250 (thousands of barrels a day)					
	United Kingdom (top)	36	32	30	31	34
	North America (bottom)	138	127	150	174	177
	Total	174	159	180	205	211
	This stacked vertical bar graph has the total for each bar printed above it.					

Exhibit 13 Page No.	Graph Narrative(Contd.)

11 CAPITAL EXPENDITURES – REFINING AND MARKETING

Scale 0 to 250 (millions of dollars)

	1998	1999	2000	2001	2002
United Kingdom (top)	7	12	13	12	4
North America (bottom)	48	76	141	163	231
Total	55	88	154	175	235

This stacked vertical bar graph has the total for each bar printed above it.

12 INCOME CONTRIBUTION FROM CONTINUING OPERATIONS BY FUNCTION

Excludes nonrecurring items and Corporate activities

Scale (60) to 360 (millions of dollars)

	1998	1999	2000	2001	2002
Exploration and Production (left)	3	115	271	186	168
Refining and Marketing (right)	49	15	55	89	(40)
Total	52	130	326	275	128

This vertical bar graph has the total for each bar printed above it and a combined annual total at the top of the graph.

12 CASH FLOW FROM CONTINUING OPERATIONS BY FUNCTION

Excludes nonrecurring items, Corporate activities and changes in noncash working capital.

Scale 0 to 750 (millions of dollars)

	1998	1999	2000	2001	2002
Exploration and Production (left)	237	340	561	573	597
Refining and Marketing (right)	89	36	120	158	44
Total	326	376	681	731	641

This stacked vertical bar graph has the total for each bar printed above it and a combined annual total at the top of the graph.

EXHIBIT 21

MURPHY OIL CORPORATION

SUBSIDIARIES OF THE REGISTRANT AS OF DECEMBER 31, 2002

Name of Company				State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
Murphy Oil Corporation (REGISTRANT)					
A.	Caledonia Land Company			Delaware	100.0
B.	El Dorado Engineering Inc.			Delaware	100.0
	1.	El Dorado Contractors Inc.		Delaware	100.0
C.	Marine Land Company			Delaware	100.0
D.	Murphy Eastern Oil Company			Delaware	100.0
E.	Murphy Exploration & Production Company			Delaware	100.0
	1.	Canam Offshore A. G. (Switzerland)		Switzerland	100.0
	2.	Canam Offshore Limited		Bahamas	100.0
		a.	Murphy Ireland Offshore Limited	Bahamas	100.0
	3.	El Dorado Exploration, S.A.		Delaware	100.0
	4.	Mentor Holding Corporation		Delaware	100.0
		a.	Mentor Excess and Surplus Lines Insurance Company	Delaware	100.0
		b.	Mentor Insurance and Reinsurance Company	Louisiana	100.0
		c.	Mentor Insurance Limited	Bermuda	99.993
		(1)	Mentor Insurance Company (U.K.) Limited	England	100.0
		(2)	Mentor Underwriting Agents (U.K.) Limited	England	100.0
	5.	Murphy Brazil Exploracao e Producao de Petroleo e Gas Ltda. (see company E12a below)		Brazil	90.0
	6.	Murphy Building Corporation		Delaware	100.0
	7.	Murphy Central Asia Oil Co., Ltd.		Bahamas	100.0
	8.	Murphy Ecuador Oil Company Ltd.		Bermuda	100.0
	9.	Murphy Exploration (Alaska), Inc.		Delaware	100.0
	10.	Murphy Faroes Oil Co., Ltd.		Bahamas	100.0
	11.	Murphy Italy Oil Company		Delaware	100.0
	12.	Murphy Overseas Ventures Inc.		Delaware	100.0
		a.	Murphy Brazil Exploracao e Producao de Petroleo e Gas Ltda. (see company E5 above)	Brazil	10.0
	13.	Murphy Pakistan Oil Company		Delaware	100.0
	14.	Murphy Sabah Oil Co., Ltd.		Bahamas	100.0
	15.	Murphy Sarawak Oil Co., Ltd.		Bahamas	100.0
	16.	Murphy Peninsular Malaysia Oil Co., Ltd.		Bahamas	100.0
	17.	Murphy Somali Oil Company		Delaware	100.0
	18.	Murphy South Asia Oil Co., Ltd.		Bahamas	100.0
	19.	Murphy-Spain Oil Company		Delaware	100.0
	20.	Ocean Exploration Company		Delaware	100.0
	21.	Odeco Drilling (UK) Limited		England	100.0
	22.	Odeco Italy Oil Company		Delaware	100.0
	23.	Sub Sea Offshore (M) Sdn. Bhd.		Malaysia	60.0

EXHIBIT 21 (Contd.)

MURPHY OIL CORPORATION

SUBSIDIARIES OF THE REGISTRANT AS OF DECEMBER 31, 2002 (Contd.)

Name of Company				State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
Murphy Oil Corporation (REGISTRANT) – Contd.					
F.	Murphy Oil Company Ltd.			Canada	100.0
	1.	Murphy Atlantic Offshore Finance Company Ltd.		Canada	100.0
	2.	Murphy Atlantic Offshore Oil Company Ltd.		Canada	100.0
	3.	Murphy Canada Exploration Company		NSULCo.*	100.0
		a.	Belmoral Marketing Corporation	Canada	100.0
		b.	Environmental Technologies Inc.	Canada	52.0
			(1) Eastern Canadian Coal Gas Venture Ltd.	Canada	100.0
	4.	Murphy Finance Company		NSULCo.*	100.0
	5.	Murphy Canada, Ltd.		Canada	100.0
G.	Murphy Oil USA, Inc.			Delaware	100.0
	1.	864 Beverage, Inc.		Texas	100.0
	2.	Arkansas Oil Company		Delaware	100.0
	3.	Murphy Gas Gathering Inc.		Delaware	100.0
	4.	Murphy Latin America Refining & Marketing, Inc.		Delaware	100.0
	5.	Murphy LOOP, Inc.		Delaware	100.0
	6.	Murphy Oil Trading Company (Eastern)		Delaware	100.0
	7.	Spur Oil Corporation		Delaware	100.0
	8.	Superior Crude Trading Company		Delaware	100.0
H.	Murphy Realty Inc.			Delaware	100.0
I.	Murphy Ventures Corporation			Delaware	100.0
J.	New Murphy Oil (UK) Corporation			Delaware	100.0
	1.	Murphy Petroleum Limited		England	100.0
		a.	Alnery No. 166 Ltd.	England	100.0
		b.	H. Hartley (Doncaster) Ltd.	England	100.0
		c.	Murco Petroleum Limited	England	100.0
			(1) European Petroleum Distributors Ltd.	England	100.0
			(2) Murco Petroleum (Ireland) Ltd.	Ireland	100.0

* Denotes Nova Scotia Unlimited Liability Company.

EXHIBIT 23

Independent Auditors' Consent

The Board of Directors
Murphy Oil Corporation:

We consent to the incorporation by reference in the Registration Statements (Nos. 2-82818, 2-86749, 2-86760, 333-27407, 333-43030, and 333-57806) on Form S-8 and (Nos. 33-55161 and 333-84547) on Form S-3 of Murphy Oil Corporation of our report dated February 14, 2003, with respect to the consolidated balance sheets of Murphy Oil Corporation and Consolidated Subsidiaries as of December 31, 2002 and 2001, 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, 2002, which report appears in the December 31, 2002 annual report on Form 10-K of Murphy Oil Corporation.

Our report refers to a change in the method of accounting for goodwill and other intangible assets and a change in the method of accounting for derivative instruments and hedging activities.

KPMG LLP

March 20, 2003

EXHIBIT 99.1

UNDERTAKINGS

To be incorporated by reference into Form S-8 Registration Statement Nos. 2-82818, 2-86749, 2-86760, 333-27407, 333-43030 and 333-57806, and Form S-3 Registration Statement Nos. 33-55161 and 333-84547.

The undersigned registrant hereby undertakes:

(1) To file, during any period in which offers or sales are being made, a post-effective amendment to this registration statement:

(i) To include any prospectus required by section 10(a)(3) of the Securities Act of 1933;

(ii) To reflect in the prospectus any facts or events arising after the effective date of the registration statement (or the most recent post-effective amendment thereof) which, individually or in the aggregate, represents a fundamental change in the information set forth in the registration statement;

(iii) To include any material information with respect to the plan of distribution not previously disclosed in the registration statement or any material change to such information in the registration statement.

(2) That, for the purpose of determining any liability under the Securities Act of 1933, each such post-effective amendment shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

(3) To remove from registration by means of a post-effective amendment any of the securities being registered which remain unsold at the termination of the offering.

The undersigned registrant hereby undertakes that, for purposes of determining any liability under the Securities Act of 1933, each filing of the registrant's annual report pursuant to section 13(a) or section 15(d) of the Securities Exchange Act of 1934 (and, where applicable, each filing of an employee benefit plan's annual report pursuant to section 15(d) of the Securities Exchange Act of 1934) that is incorporated by reference in the registration statement shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

The undersigned registrant hereby undertakes:

(1) To deliver or cause to be delivered with the prospectus to each employee to whom the prospectus is sent or given a copy of the registrant's annual report to stockholders for its last fiscal year, unless such employee otherwise has received a copy of such report, in which case the registrant shall state in the prospectus that it will promptly furnish, without charge, a copy of

such report on written request of the employee. If the last fiscal year of the registrant has ended within 120 days prior to the use of the prospectus, the annual report of the registrant for the preceding fiscal year may be so delivered, but within such 120 day period the annual report for the last fiscal year will be furnished to each such employee.

(2) To transmit or cause to be transmitted to all employees participating in the plan who do not otherwise receive such material as stockholders of the registrant, at the time and in the manner such material is sent to its stockholders, copies of all reports, proxy statements and other communications distributed to its stockholders generally.

Where interests in a plan are registered herewith, the undersigned registrant and plan hereby undertake to transmit or cause to be transmitted promptly, without charge, to any participant in the plan who makes a written request, a copy of the then latest annual report of the plan filed pursuant to section 15(d) of the Securities Exchange Act of 1934 (Form 11-K). If such report is filed separately on Form 11-K, such form shall be delivered upon written request. If such report is filed as a part of the registrant's annual report on Form 10-K, that entire report (excluding exhibits) shall be delivered upon written request. If such report is filed as a part of the registrant's annual report to stockholders delivered pursuant to paragraph (1) or (2) of this undertaking, additional delivery shall not be required.

Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, or otherwise, the registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

Exhibit 99.2

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

In connection with the Annual Report of Murphy Oil Corporation (the “Company”) on Form 10-K for the period ending December 31, 2002 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Claiborne P. Deming, Principal Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ Claiborne P. Deming

Claiborne P. Deming
Principal Executive Officer
March 21, 2003

Exhibit 99.3

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

In connection with the Annual Report of Murphy Oil Corporation (the “Company”) on Form 10-K for the period ending December 31, 2002 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Steven A. Cossé, Principal Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ Steven A. Cossé

Steven A. Cossé
Principal Financial Officer
March 21, 2003