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

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended DECEMBER 31, 1998

OR

[_] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ________________ to __________

Commission file number 1-8590

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

DELAWARE	71-0361522
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
200 PEACH STREET, P. O. BOX 7000, EL DORADO, ARKANSAS	71731-7000
(Address of principal executive offices)	(Zip Code)

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

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

Title of each class	Name of each exchange on which registered
COMMON STOCK, $1.00 PAR VALUE	NEW YORK STOCK EXCHANGE THE TORONTO STOCK EXCHANGE
SERIES A PARTICIPATING CUMULATIVE PREFERRED STOCK PURCHASE RIGHTS	NEW YORK STOCK EXCHANGE THE 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 X No ___.

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

Aggregate market value of the voting stock held by non-affiliates of the registrant, based on average price at January 29, 1999, as quoted by the New York Stock Exchange, was approximately $1,220,526,000.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 29, 1999, was 44,952,042.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 12, 1999, have been incorporated by reference in Part III herein.

MURPHY OIL CORPORATION

TABLE OF CONTENTS - 1998 FORM 10-K REPORT

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 the United States and the United Kingdom and pipeline and crude oil trading operations in Canada. 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, Marketing and Transportation." For reporting purposes, Murphy's exploration and production activities are subdivided into five geographic segments -- the United States, Canada, the United Kingdom, Ecuador, and all other countries; Murphy's refining, marketing and transportation activities are subdivided into three geographic segments -- the United States, the United Kingdom and Canada. Additionally, "Corporate and Other Activities" include interest income, interest expense and overhead not allocated to the segments. On December 31, 1996, Murphy completed a spin-off to its stockholders of its wholly owned farm, timber and real estate subsidiary, Deltic Farm & Timber Co., Inc. (reincorporated as "Deltic Timber Corporation").

The information appearing in the 1998 Annual Report to Security Holders (1998 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 relative to Murphy's operations, properties and business segments, including revenues by class of products and financial information by geographic area, are described on pages 7, F-8, F-19 through F-21, F-24 through F-26, and F-28 of this Form 10-K report and on pages 6 through 19 of the 1998 Annual Report.

EXPLORATION AND PRODUCTION

During 1998, Murphy's principal exploration and production activities were conducted in the United States and Ecuador 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 1998 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 extracts synthetic crude oil from oil sand deposits in northern Alberta. Subsidiaries of Murphy Expro conducted exploration activities in various other areas including the Falkland Islands, China, Ireland, the Faroe Islands, Spain, Philippines, Peru and Pakistan.

Murphy's estimated net quantities of proved oil and gas reserves and proved developed oil and gas reserves at December 31, 1995, 1996, 1997 and 1998 by geographic area are reported on page F-23 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 net natural gas sales by geographic area with weighted average sales prices for each of the five years ended December 31, 1998, are shown on page 21 of the 1998 Annual Report.

Production costs for the last three years in U.S. dollars per equivalent barrel produced are discussed on page 11 of this Form 10-K report. For purposes of these computations, natural gas 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-22 through F-27 of this Form 10-K report.

At December 31, 1998, Murphy held leases, concessions, contracts or permits on nonproducing and producing 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.

	NONPRODUCING		PRODUCING		TOTAL	
AREA (THOUSANDS OF ACRES)	GROSS	NET	GROSS	NET	GROSS	NET
United States - Onshore	5	3	39	20	44	23
- Gulf of Mexico	832	482	369	136	1,201	618
- Frontier	117	40	--	--	117	40
Total United States	954	525	408	156	1,362	681
Canada - Onshore	813	582	1,084	155	1,897	737
- Offshore	941	178	5	--	946	178
- Oil sands	225	54	13	4	238	58
Total Canada	1,979	814	1,102	159	3,081	973
United Kingdom	1,439	461	78	11	1,517	472
Ecuador	--	--	494	99	494	99
China	563	253	--	--	563	253
Falkland Islands	401	100	--	--	401	100
Ireland	896	224	--	--	896	224
Malaysia	6,498	5,319	--	--	6,498	5,319
Pakistan	3,795	3,795	--	--	3,795	3,795
Philippines	3,695	2,956	--	--	3,695	2,956
Spain	434	136	--	--	434	136
Tunisia	109	36	--	--	109	36
Total	20,763	14,619	2,082	425	22,845	15,044

Oil and gas wells producing or capable of producing at December 31, 1998, are summarized in the following table. Gross wells are those in which all or part of the working interest is owned by Murphy. Net wells are the portions of the gross wells applicable to Murphy's working interest.

	OIL WELLS		GAS WELLS	
COUNTRY	GROSS	NET	GROSS	NET
United States	323	143.5	272	106.7
Canada	4,173	827.0	815	286.0
United Kingdom	98	12.3	21	1.5
Ecuador	53	10.6	--	--
Total	4,647	993.4	1,108	394.2
Wells included above with multiple completions and counted as one well each	87	41.1	90	64.7

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

	UNITED STATES		CANADA		UNITED KINGDOM		ECUADOR		OTHER		TOTAL	
	PRO-DUCTIVE	DRY	PRO-DUCTIVE	DRY	PRO-DUCTIVE	DRY	PRO-DUCTIVE	DRY	PRO-DUCTIVE	DRY	PRO-DUCTIVE	DRY
1998												
Exploratory	9.0	.8	4.8	7.5	--	--	--	--	--	1.0	13.8	9.3
Development	.6	--	5.4	--	1.9	--	1.2	--	--	--	9.1	--
1997												
Exploratory	7.6	6.8	15.8	8.3	.5	.6	--	--	.4	1.0	24.3	16.7
Development	2.9	--	83.0	--	.9	.3	1.6	--	--	--	88.4	.3
1996												
Exploratory	13.8	3.9	5.3	4.0	--	1.1	--	--	.4	--	19.5	9.0
Development	4.6	--	70.2	2.5	1.0	.1	2.2	--	--	--	78.0	2.6

Murphy's drilling wells in progress at December 31, 1998, are summarized below.

	EXPLORATORY		DEVELOPMENT		TOTAL	
COUNTRY	GROSS	NET	GROSS	NET	GROSS	NET
United States	2	.8	1	--	3	.8
Canada	1	.5	2	.2	3	.7
United Kingdom	-	-	3	.3	3	.3
Ecuador	-	-	1	.2	1	.2
Total	3	1.3	7	.7	10	2.0

Additional information about current exploration and production activities is reported on pages 1 through 15 of the 1998 Annual Report.

REFINING, MARKETING AND TRANSPORTATION

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, 1998, 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
Pretreating cat-reforming feeds	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	2,250	4,250
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	4,453,000	2,852,000	2,638,000	9,943,000

*Barrels per stream day.

Murphy distributes refined products from 59 terminal locations in the United States to retail and wholesale accounts in the United States (by MOUSA) and in Canada (by a MOCL subsidiary) under the brand names SPUR(R) and Murphy USA(R) and to unbranded wholesale accounts. Eleven of these terminals are wholly owned and operated by MOUSA, 16 are jointly owned and operated by others, and the remaining 32 are 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 in exchange for deliveries from the Company's wholly owned and jointly owned terminals. At the end of 1998, refined products were marketed at wholesale or retail through 552 branded stations in 17 states in the Southeast and Upper Midwest and eight branded stations in the Thunder Bay area of Ontario, Canada.

At the end of 1998, Murco distributed refined products in the United Kingdom from the Milford Haven refinery, three wholly owned terminals supplied by rail, seven terminals owned by others where products are received in exchange for deliveries from the Company's wholly owned terminals, and 389 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 Murphy's marketing area in the southeastern United States. The Company also owns a 22% interest in a 312-mile crude oil pipeline in Montana and Wyoming, with a capacity of 120,000 barrels a day, and a 3.2% interest in LOOP Inc., which provides deepwater unloading accommodations off the Louisiana coast for oil tankers and onshore facilities for storage of crude oil. In addition, Murphy owns 29.4% of a 22-mile crude oil pipeline, with a capacity of 300,000 barrels a day, that connects LOOP storage at Clovelly, Louisiana and Alliance, Louisiana and 100% of a 24-mile crude oil pipeline, with a capacity of 200,000 barrels a day, that connects Alliance to the Meraux refinery. The pipeline from Alliance to Meraux is also connected to another company's pipeline system, allowing crude oil transported by that system to be shipped to the Meraux refinery.

At December 31, 1998, MOCL operated the following Canadian crude oil pipelines, with the ownership percentage, extent and capacity in barrels a day of each as shown. MOCL also operated and owned all or most of several short lateral connecting pipelines.

PIPELINE	DESCRIPTION	PERCENT	MILES	BBLS./DAY	ROUTE
Manito	Dual heavy oil	52.5	101	65,000	Dulwich to Kerrobert, Sask.
North-Sask	Dual heavy oil	36.1	40	20,000	Paradise Hill to Dulwich, Sask.
Cactus Lake	Dual heavy oil	13.1	40	50,000	Cactus Lake to Kerrobert, Sask.
Bodo	Dual heavy oil	41.3	15	18,000	Bodo, Alta. to Cactus Lake, Sask.
Milk River	Dual medium/light oil	100	10.5	118,000	Milk River, Alta. to U.S. border
Wascana	Single light oil (idle)	100	108	45,000	Regina, Sask. to U.S. border
Senlac	Dual heavy oil	100	28	15,000	Senlac to Unity, Sask.

Additional information about current refining, marketing and transportation activities and a statistical summary of key operating and financial indicators for each of the five years ended December 31, 1998, are reported on pages 2, 3, 5, 16 through 19, and 22 of the 1998 Annual Report.

EMPLOYEES

Murphy had 1,566 full-time and part-time employees at December 31, 1998.

COMPETITION AND OTHER CONDITIONS WHICH MAY AFFECT BUSINESS

Murphy operates in the oil industry and experiences intense competition from other oil and gas companies, many of which have substantially greater resources. 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 occasionally purchases refined products and may therefore 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" on page 18 of this Form 10-K report.

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" on page 15 of this Form 10-K report), preferential and discriminatory awarding of oil and gas leases, 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 dictated 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 policy is to insure against known risks when insurance is available at costs and terms Murphy considers reasonable. Certain existing risks are insured by Murphy only through Oil Insurance Limited (OIL), which is operated as a mutual insurance company by certain participating oil companies including Murphy. OIL was organized to insure against risks for which commercial insurance is unavailable or for which the cost of commercial insurance is prohibitive.

EXECUTIVE OFFICERS OF THE REGISTRANT

The age at January 1, 1999, 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.

R. Madison Murphy - Age 41; Chairman of the Board since October 1994. Mr. Murphy had been Executive Vice President and Chief Financial and Administrative Officer, Director and Member of the Executive Committee since 1993. Prior to that, he was Executive Vice President and Chief Financial Officer from 1992 to 1993; Vice President, Planning/Treasury, from 1991 to 1992; and Vice President, Planning, from 1988 to 1991, with additional duties as Treasurer from 1990 until August 1991.

Claiborne P. Deming - Age 44; President and Chief Executive Officer since October 1994 and Director and Member of the Executive Committee since 1993. In 1992, he became Executive Vice President and Chief Operating Officer. Mr. Deming was President of MOUSA from 1989 to 1992.

Steven A. Cosse' - Age 51; Senior Vice President since October 1994 and General Counsel since August 1991. Mr. Cosse' was elected Vice President in 1993. For the eight years prior to August 1991, he was General Counsel for Murphy Expro, at that time named Ocean Drilling & Exploration Company (ODECO), a majority-owned subsidiary of Murphy.

Herbert A. Fox Jr. - Age 64; Vice President since October 1994. Mr. Fox has also been President of MOUSA since 1992. He served with MOUSA as Vice President, Manufacturing, from 1990 to 1992.

Bill H. Stobaugh - Age 47; Vice President since May 1995, when he joined the Company. Prior to that, he had held various engineering, planning and managerial positions, most recently with an engineering consulting firm.

Odie F. Vaughan - Age 62; Treasurer since August 1991. From 1975 through July 1991, he was with ODECO as Vice President of Taxes and Treasurer.

Ronald W. Herman - Age 61; Controller since August 1991. He was Controller of ODECO from 1977 through July 1991.

Walter K. Compton - Age 36; 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

Following a 1998 compliance inspection of the Superior, Wisconsin refinery, the Company received from the U.S. Environmental Protection Agency notices of violations of the Clean Air Act. Although the penalty amounts were not listed, the statutes involved provide for rates up to $27,500 per day of violation, and penalties therefore could exceed $100,000. The Company believes it has valid defenses to the alleged violations and plans a vigorous defense. While the notices of violation are preliminary in nature and no assurances can be given, the Company does not believe that the ultimate resolution of the matter will have a material adverse effect on the financial condition of the Company.

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.

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 1998.

PART II

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

The Company's Common Stock is listed on the New York Stock Exchange and The Toronto Stock Exchange using "MUR" as the trading symbol. There were 3,684 stockholders of record as of December 31, 1998. Information as to high and low market prices per share and dividends per share by quarter for 1998 and 1997 are reported on page F-28 of this Form 10-K report.

Item 6. SELECTED FINANCIAL DATA

(THOUSANDS OF DOLLARS EXCEPT PER SHARE DATA)	1998	1997	1996	1995	1994
RESULTS OF OPERATIONS FOR THE YEAR/1/					
Sales and other operating revenues/2/	$1,694,470	2,133,387	2,009,736	1,613,848	1,582,091
Net cash provided by continuing operations	321,091	401,843	472,480	309,878	312,251
Income (loss) from continuing operations	(14,394)	132,406	125,956	(127,919)	89,347
Net income (loss)	(14,394)	132,406	137,855	(118,612)	106,628
Per Common share - diluted					
Income (loss) from continuing operations	(.32)	2.94	2.80	(2.85)	1.99
Net income (loss)	(.32)	2.94	3.07	(2.65)	2.38
Cash dividends per Common share	1.40	1.35	1.30	1.30	1.30
Percentage return on					
Average stockholders' equity	(1.3)	12.7	12.2	(9.3)	8.6
Average borrowed and invested capital	(.6)	10.4	10.4	(7.9)	8.0
Average total assets	(.6)	6.0	6.2	(5.2)	4.8
CAPITAL EXPENDITURES FOR THE YEAR					
Exploration and production	$ 331,647	423,181	373,984	231,718	286,348
Refining, marketing and transportation	55,025	37,483	42,880	53,602	94,697
Corporate and other	2,127	7,367	1,192	1,831	4,876
	$ 388,799	468,031	418,056	287,151	385,921
FINANCIAL CONDITION AT DECEMBER 31					
Current ratio	1.15	1.10	1.10	1.22	1.14
Working capital	$ 56,616	48,333	56,128	87,388	61,750
Net property, plant and equipment	1,662,362	1,655,838	1,556,830	1,377,455	1,558,716
Total assets	2,164,419	2,238,319	2,243,786	2,098,466	2,297,459
Long-term debt	333,473	205,853	201,828	193,146	172,289
Stockholders' equity	978,233	1,079,351	1,027,478/3/	1,101,145	1,270,679
Per share	21.76	24.04	22.90	24.56	28.34
Long-term debt - percent of capital employed	25.4	16.0	16.4	14.9	11.9

/1/Includes effects on income of special items in 1998, 1997 and 1996 that are detailed in Management's Discussion and Analysis of Financial Condition and Results of Operations. Also, special items in 1995 and 1994 increased (decreased) net income by $(152,066), $(3.39) a diluted share, and $20,236, $.45 a diluted share, respectively.

/2/Amounts prior to 1998 have been restated to conform to 1998 presentation.

/3/Reflects $172,561 charge for distribution of common stock of Deltic Timber Corporation to stockholders.

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

RESULTS OF OPERATIONS

The Company reported a net loss in 1998 of $14.4 million, $.32 a diluted share, compared to net income in 1997 of $132.4 million, $2.94 a diluted share. In 1996, the Company earned $137.9 million, $3.07 a diluted share. Results of operations for the three years ended December 31, 1998, included certain special items that resulted in a net charge of $57.9 million, $1.29 a diluted share, in 1998; a net benefit of $.1 million, with no per share effect, in 1997; and a net benefit of $22.2 million, $.49 a diluted share, in 1996. The 1998 special items included an after-tax charge of $57.6 million, $1.28 a diluted share, from a write-down of assets determined to be impaired under Statement of Financial Accounting Standards (SFAS) No. 121. Net income for 1996 included earnings from discontinued operations of $11.9 million, $.27 a diluted share. This amount was attributable to the activities of the Company's farm, timber and real estate subsidiary, which was spun off to the Company's shareholders on December 31, 1996, as described in Note B to the consolidated financial statements.

1998 vs. 1997 - Excluding special items, income from continuing operations totaled $43.5 million in 1998, $.97 a diluted share, a decrease of $88.8 million from the $132.3 million earned in 1997. The income reduction was primarily attributable to a $79.2 million decline in earnings from the Company's exploration and production operations. Sharply lower crude oil prices in 1998 were the main reason for the reduction. The Company's average crude oil sales price declined by $5.62 a barrel in 1998, down 34% from oil prices realized in 1997. Higher crude oil production from new fields in Canada and the United Kingdom were mostly offset by lower production from maturing U.S. and U.K. oil fields and by selective shut-in of Canadian heavy oil production. Natural gas sales prices in the United States declined 15% in 1998 and U.S. natural gas production was down 20%. Earnings from the Company's refining, marketing and transportation operations were down $7.5 million in 1998, as record levels of finished product sales volumes were more than offset by lower unit margins on product sales in the United States. The costs of corporate activities, which includes interest income and expense and corporate overhead not allocated to operating functions, increased $2.1 million in 1998 compared to 1997, primarily due to higher net interest costs offset in part by lower costs of awards under the Company's incentive plans.

1997 vs. 1996 - Excluding special items, income from continuing operations in 1997 totaled $132.3 million, $2.94 a diluted share. The results for 1997 represented a $28.5 million improvement compared to income from continuing operations of $103.8 million, $2.31 a diluted share, in 1996. Earnings from the Company's exploration and production operations declined $16.8 million in 1997, primarily due to higher exploration costs. Increases in crude oil production and natural gas sales led to record hydrocarbon production in 1997 of 102,272 barrels a day on an energy equivalent basis. However, lower worldwide crude oil sales prices nearly offset the benefit of higher production volumes. Income from the Company's refining, marketing and transportation segment was up $42.6 million in 1997. The improvement occurred primarily in the United States, where the effects of lower costs for crude oil and other feedstocks exceeded the decline in sales realizations for the Company's finished products. An improved onstream rate helped the Company's U.S. refineries achieve a record level of crude oil throughputs in 1997. Sales of finished products in the United States were also higher during 1997. The cost of corporate activities decreased $2.7 million in 1997 compared to 1996, primarily due to lower costs of awards under the Company's incentive plans.

In the following table, the Company's results of operations for the three years ended December 31, 1998, are presented by segment. Special items, which can obscure underlying trends of operating results and affect comparability between years, are set out separately. More detailed reviews of operating results for the Company's exploration and production and refining, marketing and transportation activities follow the table.

(MILLIONS OF DOLLARS)	1998	1997	1996
Exploration and production			
United States	$ 20.1	56.5	50.4
Canada	2.6	18.8	27.6
United Kingdom	.7	13.1	14.7
Ecuador	2.4	12.9	13.8
Other	(20.0)	(16.3)	(4.7)
	5.8	85.0	101.8
Refining, marketing and transportation			
United States	27.7	41.3	1.8
United Kingdom	16.8	9.2	6.2
Canada	4.7	6.2	6.1
	49.2	56.7	14.1
Corporate	(11.5)	(9.4)	(12.1)
Income from continuing operations before special items	43.5	132.3	103.8
Impairment of long-lived assets	(57.6)	(16.2)	--
Charge resulting from cancellation of a drilling rig contract	(4.2)	--	--
Write-down of crude oil inventories to market value	(4.2)	--	--
Modification of U.K. long-term sales contract	2.8	--	--
Gain on sale of assets	2.9	11.5	17.7
Net recovery (loss) pertaining to 1996 modifications of foreign crude oil contracts	2.4	1.6	(.6)
Refund and settlement of income tax matters	--	3.2	5.1
Income (loss) from continuing operations	(14.4)	132.4	126.0
Income from discontinued operations	--	--	11.9
Net income (loss)	$ (14.4)	132.4	137.9

EXPLORATION AND PRODUCTION - Earnings from exploration and production operations before special items were $5.8 million in 1998, $85 million in 1997 and $101.8 million in 1996. The decline in 1998 was primarily due to lower worldwide crude oil sales prices, which averaged $10.81 a barrel in 1998 compared to $16.43 in 1997. Lower U.S. natural gas sales prices and volumes also contributed to the decline. Partial offsets were provided by higher crude oil production and lower exploration costs. Crude oil production from new fields in the United Kingdom brought on stream during the third quarter of 1998 and from the Hibernia field, offshore Newfoundland, which came on stream in late 1997, were partially offset by selective shut-in of heavy oil production in western Canada in response to lower heavy oil prices and by lower production from mature oil fields in the United States and the United Kingdom. In 1997, a $24.6 million increase in exploration costs, primarily in the U.S. Gulf of Mexico and Bohai Bay, China, accounted for the decline in earnings. While crude oil production increased 8% and natural gas sales increased 22% in 1997, these favorable production volumes were mostly offset by a 13% decline in the average worldwide crude oil sales price.

The results of operations for oil and gas producing activities for each of the last three years are shown by major operating area on pages F-25 and F-26 of this Form 10-K report. Daily production rates and weighted average sales prices are shown on page 21 of the 1998 Annual Report.

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

(MILLIONS OF DOLLARS)	1998	1997	1996
United States			
Crude oil	$ 35.6	74.9	86.1
Natural gas	132.1	196.7	147.1
Canada			
Crude oil	55.4	71.6	81.6
Natural gas	24.0	22.1	17.3
Synthetic oil	53.0	67.9	63.3
United Kingdom			
Crude oil	70.3	95.3	102.1
Natural gas	10.0	12.2	14.4
Ecuador - crude oil	19.1	34.7	35.0
Spain - natural gas	-	-	7.8
Total oil and gas revenues	$399.5	575.4	554.7

The Company's crude oil and gas liquids production averaged 59,128 barrels a day in 1998, 57,494 in 1997 and 53,210 in 1996. Crude oil and liquids production in the United States declined 28% in 1998, with the reduction primarily due to declining production at mature oil fields in the Gulf of Mexico. In 1997, U.S. production was down 8% from 1996, primarily due to the sale of onshore producing properties effective July 1, 1996. For the second straight year, production in Canada rose 12%, and in 1998 established a record of 28,199 barrels a day. As a result of the selective shut-in, production of heavy oil in Canada decreased 16% in 1998 compared to a 19% increase in 1997. The Company's net interest in production of synthetic oil in Canada increased 12% in 1998, after a 14% increase in 1997. The increase in net synthetic oil production in 1998 was due to a 1% increase in gross production and a decrease in the net profits royalty rate as a result of lower oil prices. The increase in net production in 1997 was due to a 3% increase in gross production and a decrease in the net profits royalty rate. Before royalties, the Company's synthetic oil production was 10,501 barrels a day in 1998, 10,371 in 1997 and 10,036 in 1996. The Company's Hibernia field, on stream for all of 1998, produced 4,192 barrels a day in 1998 compared to 224 in 1997 after production commenced in the fourth quarter. The Company's U.K. oil production increased 11% in 1998 after a 5% increase in 1997. Oil production from the Mungo/Monan and Schiehallion fields commenced in the third quarter of 1998 and averaged 2,025 and 1,219 barrels a day, respectively. Production from the "T" Block field in the United Kingdom declined by 18% during 1998. A full year of production from the Thelma field contributed to an 11% increase in "T" Block production in 1997. Production from Ninian, the Company's other major North Sea oil field, declined 8% in 1998 after having declined 3% in 1997. Production in Ecuador was essentially unchanged in 1998 after a 30% increase in 1997. The 1997 increase resulted from new fields being placed on stream throughout 1996.

Worldwide sales of natural gas averaged 230.9 million cubic feet a day in 1998, 268.7 million in 1997 and 220.6 million in 1996. A 20% decline in U.S. natural gas sales in 1998 was mainly due to reduced deliverability in certain of the Company's maturing Gulf of Mexico fields. Sales of natural gas in the United States increased 36% in 1997 as a number of new fields came on stream in the Gulf of Mexico. Natural gas sales in Canada in 1998 were at record levels for the third straight year, as sales increased 9% in 1998 following a 4% increase in 1997. Natural gas sales in the United Kingdom were down 2% in 1998, compared to a 17% decrease in 1997. Production of natural gas in Spain ceased at the end of 1996.

As previously indicated, worldwide crude oil sales prices weakened considerably throughout 1998. The declining 1998 sales prices followed a previous softening of prices in 1997 as compared to 1996 prices. In the United States, Murphy's 1998 average monthly sales prices for crude oil and condensate ranged from $9.65 to $15.66 a barrel, and averaged $12.76 for the year, 34% below the average 1997 price. In Canada, the average sales price for light oil was $12.03 a barrel in 1998, a decline of 32%. Heavy oil prices in Canada averaged $6.56 a barrel, down 39% from 1997. The average sales price for synthetic oil in 1998 was $13.73 a barrel, off 31% from a year earlier. The sales price for crude oil from the Hibernia field averaged $10.49 a barrel, down 31%. Sales prices in the United Kingdom were down 34% in 1998 and averaged $12.52 a barrel. Sales prices in Ecuador averaged $6.76 a barrel in 1998, down 44% compared to a year ago. U.S. oil prices decreased 4% in 1997 compared to 1996 and averaged $19.43 a barrel for the year. In Canada, crude oil prices in 1997 declined 11% for light oil, 25% for heavy oil and 6% for synthetic oil. Sales prices in the United Kingdom were down 10% in 1997 and prices in Ecuador were down 24%. Worldwide crude oil prices began to decline in the fourth quarter of 1997, and the downward trend continued throughout 1998. Oil prices remain under extreme pressure in early 1999.

Average monthly natural gas sales prices in the United States ranged from $1.73 to $2.51 an MCF during 1998. For the year, U.S. sales prices averaged $2.18 an MCF compared to $2.57 a year ago. The average price for natural gas sold in Canada during 1998 was $1.34 an MCF, essentially unchanged from the prior year, while prices in the United Kingdom declined 16% to $2.23. The decline in average U.K. sales prices primarily resulted from a modification of a long-term sales contract effective October 1, 1998. Average U.S. natural gas sales prices in 1997 were essentially unchanged compared to 1996; prices were up in Canada and the United Kingdom by 23% and 3%, respectively, during the same period. U.S. natural gas sales prices have declined sharply in early 1999.

Based on 1998 volumes and deducting taxes at marginal rates, each $1 a barrel and $.10 an MCF fluctuation in prices would have affected annual exploration and production earnings by $14.4 million and $5.3 million, respectively. The effect of these price fluctuations on consolidated net income cannot be measured because operating results of the Company's refining, marketing and transportation segments could be affected differently.

Production costs were $155.1 million in 1998, $164.8 million in 1997 and $160.5 million in 1996. These amounts are shown by major operating area on pages F-25 and F-26 of this Form 10-K report. Costs per equivalent barrel of production during the last three years were as follows.

(DOLLARS PER EQUIVALENT BARREL)	1998	1997	1996
United States	$ 3.32	2.59	3.31
Canada			
Excluding synthetic oil	3.64	4.63	3.95
Synthetic oil	8.99	11.32	12.72
United Kingdom	5.60	5.58	6.00
Ecuador	2.48	3.87	4.96
Worldwide - excluding synthetic oil	3.79	3.72	4.09

The increase in U.S. production cost per equivalent barrel in 1998 was attributable to lower production volumes combined with higher workover costs. The decline in Canada in 1998, excluding synthetic oil, was caused by higher oil production at Hibernia, voluntary shut-in of certain high-cost heavy oil production and a lower Canadian dollar exchange rate vs. the U.S. dollar. The decrease in the Canadian synthetic oil unit rate was due to lower maintenance costs, a decrease in royalty barrels due to a lower sales price and a lower Canadian dollar exchange rate. The lower cost in Ecuador in 1998 was caused by lower energy and other field operating costs during the year. The decrease in the U.S. cost per equivalent barrel in 1997 was attributable to the sale of high-cost onshore producing properties in 1996. The 1997 increase in Canada, excluding synthetic oil, was due to an increase in heavy oil production compared to light oil and to higher costs associated with an expansion of heavy oil thermal recovery projects. The decrease in the cost for synthetic oil in 1997 was due to higher gross production volumes and a decrease in royalty barrels caused by lower sales prices. Based on synthetic oil production before royalties, costs per barrel declined 2% in 1997. A lower unit cost in the United Kingdom in 1997 was due to a favorable impact from higher production at "T" Block.

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-25 and F-26 of this Form 10-K report. Certain of the expenses are included in the capital expenditure totals for exploration and production activities.

(MILLIONS OF DOLLARS)	1998	1997	1996
Included in capital expenditures			
Dry hole costs	$ 31.5	48.3	28.5
Geological and geophysical costs	17.0	26.4	24.1
Other costs	6.6	9.6	7.9
	55.1	84.3	60.5
Undeveloped lease amortization	10.5	10.5	9.7
Total exploration expenses	$ 65.6	94.8	70.2

Depreciation, depletion and amortization for exploration and production operations totaled $163.1 million in 1998, $172.4 million in 1997 and $147.6 million in 1996. The decrease in 1998 was primarily attributable to lower worldwide hydrocarbon production, while the increase in 1997 was mainly due to higher worldwide production.

REFINING, MARKETING AND TRANSPORTATION - Earnings from refining, marketing and transportation operations before special items were $49.2 million in 1998, $56.7 million in 1997 and $14.1 million in 1996. Operations in the United States earned $27.7 million in 1998 compared to $41.3 million in 1997, as average product sales realizations declined more than costs of crude oil and other refinery feedstocks. U.S. operations earned $1.8 million in 1996. Crude oil swap agreements increased earnings by $5 million in 1997 and $9.2 million in 1996. U.K. operations earned $16.8 million before special items in 1998, $9.2 million in 1997 and $6.2 million in 1996. The improvement in the United Kingdom in 1998 was caused by a larger decline for refining feedstock costs than for sales prices of finished products, coupled with higher finished product sales volumes. Canadian operations contributed $4.7 million to 1998 earnings compared to $6.2 million in 1997 and $6.1 million in 1996.

Unit margins (sales realizations less costs of crude oil, other feedstocks, refining and transportation to point of sale) averaged $1.47 a barrel in the United States in 1998, $1.79 in 1997 and $.27 in 1996. U.S. product sales were up 3% in 1998 following a 5% increase in 1997. U.S. margins came under pressure during the second half of 1998, at which time unit margins retreated substantially. U.S. margins improved considerably in 1997 after being under pressure throughout 1996. Unit margins were very weak in early 1999 and the Company was experiencing losses in its U.S. downstream operations.

Unit margins in the United Kingdom averaged $2.81 a barrel in 1998, $2.90 in 1997 and $2.08 in 1996. Sales of petroleum products were up 25% in 1998 following a 14% decline in 1997. Sales in both terminal and cargo markets increased in 1998. Cargo sales in 1997 were adversely affected by a turnaround at the Milford Haven refinery early in the year. Although margins remained relatively strong in 1998, the Company's branded outlets still face stiff competition from supermarket sales of motor fuels. Sharp declines in unit margins in the United Kingdom in early 1999 have led to losses in these operations.

Based on sales volumes for 1998 and deducting taxes at marginal rates, each $.42 a barrel ($.01 a gallon) fluctuation in unit margins would have affected annual refining and marketing profits by $17 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.

Income before special items from purchasing, transporting and reselling crude oil in Canada in 1998 was down $1.5 million as lower prices for heavy oil led to production shut-ins, which brought about lower pipeline throughputs and fewer barrels available for crude trading activities. Income in 1997 was virtually unchanged from 1996 as higher pipeline throughputs and better margins on crude oil trucking operations were offset by lower crude trading margins.

SPECIAL ITEMS - Net income for the last three years included the special items reviewed below; the quarter in which each item occurred is indicated. The effects of special items on quarterly results for 1998 and 1997 are presented on page F-28 of this Form 10-K report.

- Impairment of long-lived assets - An after-tax provision of $57.6 million was recorded in the fourth quarter of 1998 and after-tax provisions of $3.3 million and $12.9 million were recorded in the third and fourth quarters, respectively, of 1997 for the write-down of assets determined to be impaired (see Note C to the consolidated financial statements).

- Charge resulting from cancellation of a drilling rig contract - An after-tax charge of $4.2 million was recorded in the fourth quarter of 1998 resulting from cancellation of a drilling rig contract for the Terra Nova oil field, offshore eastern Canada. The contract was cancelled because management believes that current market conditions will allow a more efficient and modern rig to be obtained, reducing drilling costs for the Terra Nova project compared to what they might otherwise have been.

- Write-down of crude oil inventories to market value - An after-tax charge of $4.2 million was recorded in the fourth quarter of 1998 to establish a valuation allowance to reduce the carried amount of crude oil inventories in the United Kingdom and Canada to market values.

- Modification of U.K. long-term sales contract - An after-tax gain of $2.8 million was recorded in the second quarter of 1998 related to a modification of a U.K. long-term sales contract.

- Gain on sale of assets - After-tax gains on sale of assets included $2.9 million recorded in the fourth quarter of 1998 from sale of a U.K. service station, $11.5 million recorded in the fourth quarter of 1997 from sale of a Canadian heavy oil property, and $17.7 million recorded in the third quarter of 1996 from sale of 48 onshore producing oil and gas properties in the United States.

- Net recovery (loss) pertaining to 1996 modifications of foreign crude oil contracts - Gains of $1.4 million, $1 million and $1.6 million were recorded in the second quarter of 1998, the fourth quarter of 1998 and the fourth quarter of 1997, respectively, for partial recoveries of a 1996 loss resulting from modification to a crude oil production contract in Ecuador. A net loss of $.6 million was recorded in the fourth quarter of 1996 resulting from modifications to contracts related to crude oil production in Ecuador and Gabon (see Note N to the consolidated financial statements).

- Refund and settlement of income tax matters - A gain of $3.2 million for refund of U.K. income taxes was recorded in the third quarter of 1997. A gain of $5.1 million for settlement of income tax matters in Canada was recorded in the fourth quarter of 1996.

The income (loss) effects of special items for the three years ended December 31, 1998, are summarized by segment in the following table.

(MILLIONS OF DOLLARS)	1998	1997	1996
Exploration and production			
United States	$ (19.4)	(4.9)	17.7
Canada	(10.1)	.2	5.1
United Kingdom	(14.0)	3.2	--
Ecuador	2.4	1.6	(8.8)
Other	(15.1)	--	8.2
	(56.2)	.1	22.2
Refining, marketing and transportation			
United Kingdom	.5	--	--
Canada	(2.2)	--	--
	(1.7)	--	--
Total income (loss) from special items	$ (57.9)	.1	22.2

CAPITAL EXPENDITURES

As shown in the selected financial data on page 7 of this Form 10-K report, capital expenditures were $388.8 million in 1998 compared to $468 million in 1997 and $418.1 million in 1996. These amounts included $55.1 million, $84.3 million and $60.5 million of exploration expenditures that were expensed. Capital expenditures for exploration and production activities totaled $331.6 million in 1998, 85% of the Company's total capital expenditures for the year. Exploration and production capital expenditures in 1998 included $17 million for acquisition of undeveloped leases, $4.9 million for acquisition of proved oil and gas properties, $120.4 million for exploration activities and $189.3 million for development projects. Development expenditures included $11.2 million and $41.7 million for the Hibernia and Terra Nova oil fields, respectively, offshore Newfoundland; $27.1 million and $25.2 million for the Schiehallion and Mungo/Monan fields, respectively, offshore United Kingdom; and $10.2 million for oil fields in Ecuador. Exploration and production capital expenditures are shown by major operating area on page F-24 of this Form 10-K report. Amounts shown under "Other" included $9.5 million in 1998 from drilling two unsuccessful offshore wildcat wells in the Falkland Islands and $18.3 million in 1997 for exploration drilling and related costs in Bohai Bay, China.

Refining, marketing and transportation expenditures, detailed in the following table, were $55 million in 1998, or 14% of total capital expenditures, compared to $37.5 million in 1997 and $42.9 million in 1996.

(MILLIONS OF DOLLARS)	1998	1997	1996
Refining			
United States	$ 27.0	12.5	13.2
United Kingdom	.7	1.5	12.2
Total refining	27.7	14.0	25.4
Marketing			
United States	16.7	14.1	7.5
United Kingdom	6.1	2.2	1.3
Total marketing	22.8	16.3	8.8
Transportation			
United States	1.9	2.6	.3
Canada	2.6	4.6	8.4
Total transportation	4.5	7.2	8.7
Total	$ 55.0	37.5	42.9

U.S. refining expenditures were primarily for capital projects to keep the refineries operating efficiently and within industry standards and to study alternatives for meeting anticipated future environmentally driven changes to motor fuel specifications. Marketing expenditures included the costs of new stations, primarily on land leased in the United States from Wal-Mart Stores, and improvements and normal replacements at existing stations and terminals.

CASH FLOWS

Cash provided by continuing operations was $321.1 million in 1998, $401.8 million in 1997 and $472.5 million in 1996. Special items reduced cash flow from operations by $6.3 million in 1998 and $12.8 million in 1996, but increased cash by $3.8 million in 1997. Changes in operating working capital other than cash and cash equivalents required cash of $3.8 million and $72.4 million in 1998 and 1997, respectively, but provided cash of $77.1 million in 1996. Cash provided by continuing operations was further reduced by expenditures for refinery turnarounds and abandonment of oil and gas properties totaling $24.6 million in 1998, $14.4 million in 1997 and $10.8 million in 1996.

Cash proceeds from property sales were $9.5 million in 1998, $43.8 million in 1997 and $55.5 million in 1996. Borrowings under long-term notes payable provided $161.3 million of cash in 1998 and $9.7 million in 1997. Additional borrowings under nonrecourse debt arrangements provided $6.4 million of cash in 1997 and $23.1 million in 1996.

Capital expenditures required $388.8 million of cash in 1998, $468 million in 1997 and $418.1 million in 1996. Other significant cash outlays during the three years included $34.5 million in 1998, $17.3 million in 1997 and $11.4 million in 1996 for debt repayment. Cash used for dividends to stockholders was $62.9 million in 1998, $60.6 million in 1997 and $58.3 million in 1996.

FINANCIAL CONDITION

Year-end working capital totaled $56.6 million in 1998, $48.3 million in 1997 and $56.1 million in 1996. The current level of working capital does not fully reflect the Company's liquidity position, as the carrying values assigned to inventories under LIFO accounting were $14.7 million below current costs at December 31, 1998. Cash and equivalents at the end of 1998 totaled $28.3 million compared to $24.3 million a year ago and $109.7 million at the end of 1996.

Long-term debt increased $127.6 million during 1998 to $333.5 million at the end of the year, 25.4% of total capital employed, and included $143.8 million of nonrecourse debt incurred in connection with the acquisition and development of Hibernia. Long-term debt totaled $205.9 million at the end of 1997 compared to $201.8 million at December 31, 1996. Stockholders' equity was $1 billion at the end of 1998 compared to $1.1 billion a year ago and $1 billion at the end of 1996. A summary of transactions in the stockholders' equity accounts is presented on page F-5 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 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. Current financing arrangements are set forth in Note D to the consolidated financial statements. The Company does not expect any problem in meeting future requirements for funds.

The Company had commitments of $209 million for capital projects in progress at December 31, 1998, including $90 million related to one third of a multiyear contract for a semisubmersible drilling rig capable of drilling in 6,000 feet of water. Delivery of the rig is scheduled for 1999.

ENVIRONMENTAL

The Company's operations are 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 refineries, oil and gas fields, service stations, and terminals, for which known or potential obligations for environmental remediation exist.

Under the Company's accounting policies, a liability for an environmental obligation 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 years after a liability is recognized.

The Company's reserve for remedial obligations, which is included in "Deferred Credits and Other Liabilities" in the Consolidated Balance Sheets, contains 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 amount reserved by up to an estimated $3 million.

The Company has received notices from the U.S. Environmental Protection Agency that it is currently considered a Potentially Responsible Party (PRP) at three Superfund sites and has also been assigned responsibility by defendants at another Superfund site. The potential total cost to all parties to perform necessary remedial work at these sites may be substantial. Based on currently available information, the Company has reason to believe that it is a de minimus party as to ultimate responsibility at the four sites. The Company does not expect that its related remedial costs will be material to its financial condition or its results of operations, and it has not provided a reserve for remedial costs on Superfund sites. Additional information may become known in the future that would alter this assessment, including any requirement to bear a pro rata share of costs attributable to nonparticipating PRPs or indications of additional responsibility by the Company.

Following a compliance inspection in 1998, Murphy's Superior, Wisconsin refinery received from the U.S. Environmental Protection Agency notices of violations of the Clean Air Act. Although the penalty amounts were not listed, the statutes involved provide for rates up to $27,500 per day of violation. The Company believes it has valid defenses to the allegations and plans a vigorous defense. The Company does not believe that this or other known environmental matters will have a material adverse effect on its financial condition. There is the possibility that additional expenditures could be required at currently unidentified sites, and new or revised regulatory requirements could necessitate additional expenditures at known sites. Such expenditures could materially affect the results of operations in a future period.

Certain environmental expenditures are likely to be recovered by the Company from other sources, primarily environmental funds maintained by certain states. Since no assurance can be given that future recoveries from other sources will occur, the Company has not recorded a benefit for likely recoveries at December 31, 1998.

The Company's refineries also incur costs to handle and dispose of hazardous wastes and other chemical substances on a recurring basis. These costs are generally expensed as incurred and amounted to $3.8 million in 1998. In addition to remediation and other recurring expenditures, Murphy commits a portion of its capital expenditure program for compliance with environmental laws and regulations. Such capital expenditures were approximately $26 million in 1998 and are expected to be $44 million in 1999.

YEAR 2000 ISSUES

GENERAL - The Year 2000 issue affects all companies and relates to the possibility that computer programs and embedded computer chips may be unable to accurately process data with year dates of 2000 and beyond. Murphy is devoting significant internal and external resources to address Year 2000 compliance, and the Company's Year 2000 project (Project) is proceeding well. In 1993, Murphy began a worldwide business systems replacement project using systems primarily from J.D. Edwards & Company (Edwards) in the United States and the United Kingdom, PricewaterhouseCoopers LLP (PW*Sequel) in Canada, and for exploration and production operations, Applied Terravision Systems Inc. (Artesia) in the United States, and EFA Software Services Ltd. (PRISM) in Canada. Certain U.S. business software systems developed by the Company will not be replaced with compliant vendor systems by the Year 2000 and have been remedied to be Year 2000 compliant. Remaining hardware, software and facilities are expected to be made Year 2000 compliant through the Project. None of the Company's other information technology projects are expected to be significantly delayed due to the implementation of the Project.

PROJECT - The Company has established an Enterprise Project Office (EPO) and has engaged KPMG LLP to assist with Project management. The Project is primarily being managed by major operating location. At each location, the Project is divided into three major components: Computer Hardware, Applications Software, and Process Control and Instrumentation (Embedded Technology). The Computer Hardware component consists of computing equipment and systems software other than Applications Software. Applications Software includes both internally developed and vendor software systems. Embedded Technology includes the hardware, software and associated embedded computer chips (other than computing equipment) that are used in facilities operated by the Company. The general phases common to all components are: (1) inventorying Year 2000 items; (2) assigning priorities to identified items; (3) assessing the Year 2000 compliance of identified items; (4) repairing or replacing material items that are determined not to be Year 2000 compliant; (5) evaluating and testing required material items; and (6) designing and implementing contingency and business continuation plans as necessary. Material items are those that the Company believes to have safety, environmental or property damage risks, or that may adversely affect the Company's ability to process and record revenues if not properly addressed. The inventorying and priority assessment phases of the Project were completed during 1998. The remaining four phases of the Project are in progress and are being performed primarily by employees of the Company, with assistance from vendors and independent contractors.

A fourth major component of the Project, which involves the review of third party suppliers, customers and business partners (Third Parties), is being managed for all locations by the EPO. This includes the process of identifying and prioritizing critical Third Parties and communicating with them about their plans and progress in addressing the Year 2000 problem. Detailed evaluations of the most critical Third Parties began in the second quarter of 1998 and are scheduled for completion by June 30, 1999, with follow-up reviews scheduled for the remainder of 1999. The Company estimates that this component was on schedule at December 31, 1998. Based on the results of evaluations and other available information, contingency plans will be developed as necessary during 1999 to address any anticipated Year 2000 problems related to critical Third Parties.

A Year 2000 compliant version of Edwards has been fully implemented in the United States and is approximately 60% complete in the United Kingdom. Implementation of Edwards is ongoing in the United Kingdom and final phases are expected to be completed in October 1999. A contingency plan will be prepared in early 1999 to address the possibility that the last phases of the U.K. implementation will not be achieved by the end of 1999. A Year 2000 compliant version of Artesia was implemented in the United States at the end of 1998 and testing was completed in January 1999. In Canada, the Company expects to upgrade and test a Year 2000 compliant version of PRISM during the first quarter of 1999, with a compliant version of PW*Sequel scheduled to be fully implemented in April 1999. Testing of U.S. offshore production platform systems is scheduled to be completed by the end of the first quarter of 1999. Exploration system upgrades were released by the vendor in early 1999 and will be installed and tested by the third quarter of 1999. Remedy of certain internally developed downstream accounting, customer invoicing and human resources systems in the United States had been completed at December 31, 1998. Upgrading and testing of virtually all significant U.S. refining and marketing systems is scheduled to be completed by April 30, 1999. The operator at the Company's jointly owned U.K. refinery is directing that location's Year 2000 action plan; Company employees are monitoring the operator's progress and believe the work is on schedule. Systems at U.K. marketing terminals are being upgraded to a Year 2000 compliant version; this work is scheduled to be completed by March 31, 1999. Supply and transportation systems in Canada are expected to be essentially compliant by March 31, 1999.

PROJECT SUMMARY - At January 31, 1999, the overall Project is estimated to be 70% complete. Thus far, no material noncompliant Year 2000 issues have been discovered that were not identified in the completed Year 2000 inventory. The material components of the Project, except for the final stages of the Edwards implementation in the United Kingdom, are expected to be nearly complete by June 30, 1999.

The Company does not expect to develop formal contingency plans for Project issues that are resolved in accordance with the current schedule. Any unresolved issues that fall significantly behind schedule or that lead to a material risk of system failure will be addressed by contingency plans during 1999.

COSTS - The Company's total cost to become Year 2000 compliant is not expected to be material to its financial position. The most likely estimate of the total cost of the Project is approximately $5 million, of which $2 million is for the EPO (including assessment of Third Parties), $1 million is for miscellaneous hardware replacement, $1 million is for noncompliant system renovations and upgrades and $.6 million is for Embedded Technology issues. It is reasonably possible that total costs could exceed the most likely estimate by up to $1 million. Funds for the Project are primarily obtained from internally generated cash flows. This estimate does not include the Company's potential share of Year 2000 costs that may be incurred by partnerships and joint ventures that the Company does not operate, except for an estimated $.5 million to make Murphy's jointly owned U.K. refinery Year 2000 compliant. The cost of implementing Edwards in the United Kingdom, estimated to be $.9 million, is also not included in the Project cost estimate.

The total amount expended on the Project through December 31, 1998, and recorded in selling and general expense in 1998 was $1.6 million, most of which related to the EPO. The remaining cost to complete the Year 2000 Project is estimated to be approximately $3.4 million.

RISKS - Not correcting material Year 2000 problems could result in interruptions in, or failures of, certain normal business activities or operations. Such failures could materially and adversely affect the Company's results of operations, liquidity or financial condition by impeding the Company's ability to produce and deliver crude oil, natural gas and finished petroleum products, and to invoice and collect related revenues from customers. Due to the general uncertainty inherent in the Year 2000 problem, resulting in part from uncertainty about the Year 2000 readiness of critical Third Parties, the Company is unable to determine at this time whether or not the consequences of possible Year 2000 failures will materially affect its results of operations, liquidity or financial condition. The Project is expected to significantly reduce the Company's level of uncertainty about the Year 2000 issue, and in particular, about the Year 2000 compliance and readiness of the Company's critical Third Parties. The Company believes that it is taking reasonable steps to address potentially material Year 2000 failures, and with completion of the Project as scheduled, the possibility of significant interruptions of normal operations should be greatly reduced.

Readers are cautioned that forward-looking statements contained in this Year 2000 section should be read in conjunction with Murphy's disclosures under the heading "Forward-Looking Statements" on page 18 of this Form 10-K report.

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 is impacted by the weather, and by the fact that delivery of supplies is generally restricted to specific geographic areas. Relatively high crude oil and natural gas prices led to upward pressure on amounts paid by the Company for goods and services during 1996 and 1997. Conversely, lower commodity prices in 1998 have caused a softening of prices for goods and services in recent months.

ACCOUNTING MATTERS - The Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," in June 1997. This statement establishes accounting and reporting standards for derivative instruments and hedging activities. Effective January 1, 2000, Murphy must recognize the fair value of all derivative instruments as either assets or liabilities in its Consolidated Balance Sheet. A derivative instrument meeting certain conditions may be designated as a hedge of a specific exposure; accounting for changes in a derivative's fair value will depend on the intended use of the derivative and the resulting designation. Any transition adjustments resulting from adopting this statement will be reported in net income or other comprehensive income, as appropriate, as the cumulative effect of a change in accounting principle. As described under the heading "Quantitative and Qualitative Disclosures About Market Risk" on page 19 of this Form 10-K report, the Company makes limited use of derivative instruments to hedge specific market risks. The Company has not yet determined the effects that SFAS No. 133 will have on its future consolidated financial statements or the amount of the cumulative adjustment that will be made upon adopting this new standard.

OUTLOOK

Planning for 1999 is difficult because prices for the Company's products remain uncertain. Worldwide crude oil sales prices remain under extreme pressure in early 1999, primarily caused by soft worldwide crude oil demand due to the weak Asian economy. In addition, relatively mild winter weather has led to significantly lower U.S. natural gas sales prices in early 1999. The low oil and natural gas sales prices, coupled with weak refining and marketing margins, continue to exert downward pressure on the Company's operating results in early 1999. The Company was experiencing losses in exploration and production and refining, marketing and transportation operations in early 1999. In such an environment, constant reassessment of spending plans is required. The Company's capital expenditure budget for 1999 was prepared during the fall of 1998, but spending plans have subsequently been revised downward to reflect the effects of the sharp decline in commodity prices seen in late 1998 and early 1999. The Company's present plans call for capital expenditures of $400 million in 1999, of which $290 million or 72% is allocated for exploration and production activities. Geographically, about 33% of the planned exploration and production spending is designated for the United States; 45% for Canada, including $75 million for further development of the Terra Nova oil field and $19 million at Syncrude, primarily for expansion of the Aurora mine; 16% for the United Kingdom, including $27 million for further development costs related to the Schiehallion and Mungo/Monan oil fields; 4% for continuing development of oil fields in Ecuador; and the remaining 2% for other overseas operations. Planned refining, marketing and transportation capital expenditures for 1999 are $110 million, including $95 million in the United States, $14 million in the United Kingdom and $1 million in Canada. U.S. amounts include funds for additional stations at Wal-Mart sites. Capital and other expenditures are under constant review and planned capital expenditures may be adjusted further to reflect changes in estimated cash flow as 1999 progresses.

FORWARD-LOOKING STATEMENTS

This Form 10-K report, including documents incorporated by reference herein, 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 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, foreign currency exchange rates, and prices of crude oil, natural gas and petroleum products. Murphy makes limited use of derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions. All derivatives used for risk management are covered by operating policies and are closely monitored by the Company's senior management. The Company does not hold derivatives for trading purposes and it does not use derivatives with leveraged or complex features. Derivative instruments are traded either with creditworthy major financial institutions or over national exchanges.

At December 31, 1998, the Company was a party to interest rate swaps with notional amounts totaling $100 million that were designed to convert a similar amount of variable-rate debt to fixed rates. The swaps mature in 2002 and 2004. The swaps require the Company to pay an average interest rate of 6.46% over their composite lives, and at December 31, 1998, the interest rate to be received by the Company averaged 5.23%. 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. As described in Note I to the consolidated financial statements, the estimated fair value of these interest rate swaps was a negative $5.5 million at December 31, 1998.

At December 31, 1998, 84% of the Company's long-term debt had variable interest rates and 45% was denominated in Canadian dollars. Certain debt with fixed interest rates at the end of 1998 is expected to be refinanced through variable-rate borrowings during 1999. Based on debt outstanding at December 31, 1998, a 10% increase in variable interest rates would increase the Company's interest expense in 1999 by $1.1 million, net of a $.5 million 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 vs. the U.S. dollar would increase 1999 interest expense by $.3 million on debt denominated in Canadian dollars.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages F-1 through F-28 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 12, 1999, 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 12, 1999, under the captions "Compensation of Directors," "Executive Compensation," "Option Exercises and Fiscal Year-End Values," "Option Grants," "Compensation Committee Report for 1998," "Shareholder Return Performance Presentation" and "Retirement Plans."

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information required by this item is incorporated by reference to the Registrant's definitive Proxy Statement for the Annual Meeting of Stockholders on May 12, 1999, under the caption "Certain Stock Ownerships."

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information required by this item is incorporated by reference to the Registrant's definitive Proxy Statement for the Annual Meeting of Stockholders on May 12, 1999, under the caption "Certain Relationships and Related Transactions."

PART IV

ITEM 14. 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. FINANCIAL STATEMENT SCHEDULES

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 (*), are to be filed by an amendment as indicated by pound sign (#), or 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 of September 25, 1986	Exhibit 3.1 of Murphy's Form 10-K for the year ended December 31, 1996
3.2	Bylaws of Murphy Oil Corporation at January 24, 1996	Exhibit 3.2 of Murphy's Form 10-K for the year ended December 31, 1997
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.	
4.1	Credit Agreement among Murphy Oil Corporation and certain subsidiaries and the Chase Manhattan Bank et al as of November 13, 1997	Exhibit 4.1 of Murphy's Form 10-K for the year ended December 31, 1997

4.2	Rights Agreement dated as of December 6, 1989, between Murphy Oil Corporation and Harris Trust Company of New York, as Rights Agent	Exhibit 4.1 of Murphy's Form 10-K for the year ended December 31, 1994
4.3	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
10.1	1987 Management Incentive Plan as amended February 7, 1990, retroactive to February 3, 1988	Exhibit 10.2 of Murphy's Form 10-K for the year ended December 31, 1994
10.2	1992 Stock Incentive Plan as amended May 14, 1997	Exhibit 10.2 of Murphy's Form 10-Q for the quarterly period ended June 30, 1997
10.3	Employee Stock Purchase Plan	Exhibit 99.01 of Murphy's Form S-8 Registration Statement filed May 19, 1997, under the Securities Act of 1933
* 13	1998 Annual Report to Security Holders including Narrative to Graphic and Image Material as an Appendix	
* 21	Subsidiaries of the Registrant	
* 23	Independent Auditors' Consent	
* 27	Financial Data Schedule for 1998	
* 99.1	Undertakings	
# 99.2	Form 11-K, Annual Report for the fiscal year ended December 31, 1998, covering the Thrift Plan for Employees of Murphy Oil Corporation	To be filed as an amendment to this Form 10-K not later than 180 days after December 31, 1998
# 99.3	Form 11-K, Annual Report for the fiscal year ended December 31, 1998, 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 not later than 180 days after December 31, 1998
# 99.4	Form 11-K, Annual Report for the fiscal year ended December 31, 1998, 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 not later than 180 days after December 31, 1998

(b) Reports on Form 8-K

No reports on Form 8-K were filed during the quarter ended December 31, 1998.

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 24, 1999

Claiborne P. Deming, President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on March 24, 1999, by the following persons on behalf of the registrant and in the capacities indicated.

R. MADISON MURPHY R. Madison Murphy, Chairman and Director	MICHAEL W. MURPHY Michael W. Murphy, Director
CLAIBORNE P. DEMING Claiborne P. Deming, President and Chief Executive Officer and Director (Principal Executive Officer)	WILLIAM C. NOLAN JR. William C. Nolan Jr., Director
B. R. R. BUTLER B. R. R. Butler, Director	CAROLINE G. THEUS Caroline G. Theus, Director
GEORGE S. DEMBROSKI George S. Dembroski, Director	LORNE C. WEBSTER Lorne C. Webster, Director
H. RODES HART H. Rodes Hart, Director	STEVEN A. COSSE' Steven A. Cosse', Senior Vice President and General Counsel (Principal Financial Officer)
VESTER T. HUGHES JR. Vester T. Hughes Jr., Director	RONALD W. HERMAN Ronald W. Herman, Controller (Principal Accounting Officer)
C. H. MURPHY JR. C. H. Murphy Jr., Director	

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 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 generally accepted auditing standards 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 perform an oversight role for the financial statements. 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 the Company's internal controls, the quality of its financial reporting, and the scope and results of audits. The independent auditors and the Company's audit staff have unrestricted access to the Committee, without management's 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, 1998 and 1997, 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, 1998. 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 generally accepted auditing standards. 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, 1998 and 1997, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 1998, in conformity with generally accepted accounting principles.

KPMG LLP

Shreveport, Louisiana
March 1, 1999

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

YEARS ENDED DECEMBER 31 (THOUSANDS OF DOLLARS EXCEPT PER SHARE AMOUNTS)	1998	1997*	1996*
REVENUES			
Crude oil and natural gas sales	$ 312,253	450,785	346,310
Petroleum product sales	1,312,727	1,604,379	1,570,289
Other operating revenues	69,490	78,223	93,137
Interest and other nonoperating revenues	4,378	4,380	12,440
Total revenues	1,698,848	2,137,767	2,022,176
COSTS AND EXPENSES			
Crude oil, products and related operating expenses	1,279,619	1,527,301	1,483,914
Exploration expenses, including undeveloped lease amortization	65,582	94,792	70,206
Selling and general expenses	61,363	65,928	66,402
Depreciation, depletion and amortization	202,695	209,419	182,381
Impairment of long-lived assets	80,127	28,056	--
Charge resulting from cancellation of a drilling rig contract	7,255	--	--
Interest expense	18,090	12,717	13,120
Interest capitalized	(7,606)	(12,096)	(10,202)
Total costs and expenses	1,707,125	1,926,117	1,805,821
Income (loss) from continuing operations before income taxes	(8,277)	211,650	216,355
Federal and state income tax expense	18,469	49,062	43,860
Foreign income tax expense (benefit)	(12,352)	30,182	46,539
Income (loss) from continuing operations	(14,394)	132,406	125,956
Discontinued farm, timber and real estate operations	--	--	11,899
NET INCOME (LOSS)	$ (14,394)	132,406	137,855
PER COMMON SHARE - BASIC			
Continuing operations	$ (.32)	2.95	2.80
Discontinued operations	--	--	.27
Net income (loss)	$ (.32)	2.95	3.07
PER COMMON SHARE - DILUTED			
Continuing operations	$ (.32)	2.94	2.80
Discontinued operations	--	--	.27
Net income (loss)	$ (.32)	2.94	3.07
Average Common shares outstanding - basic	44,955,679	44,881,225	44,858,115
Average Common shares outstanding - diluted	44,955,679	44,960,907	44,904,636

*Revenues have been reclassified to conform to 1998 presentation.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

YEARS ENDED DECEMBER 31 (THOUSANDS OF DOLLARS)	1998	1997	1996
Net income (loss)	$ (14,394)	132,406	137,855
Other comprehensive income - net gain (loss) from foreign currency translation	(24,411)	(21,682)	18,005
COMPREHENSIVE INCOME (LOSS)	$ (38,805)	110,724	155,860

See notes to consolidated financial statements, page F-6.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

DECEMBER 31 (THOUSANDS OF DOLLARS)	1998	1997
ASSETS		
Current assets		
Cash and cash equivalents	$ 28,271	24,288
Accounts receivable, less allowance for doubtful accounts of $11,048 in 1998 and $13,530 in 1997	233,906	272,447
Inventories		
Crude oil and blend stocks	41,090	55,075
Finished products	49,714	64,394
Materials and supplies	38,973	38,947
Prepaid expenses	32,292	47,323
Deferred income taxes	13,120	15,278
Total current assets	437,366	517,752
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $2,985,854 in 1998 and $2,762,805 in 1997	1,662,362	1,655,838
Deferred charges and other assets	64,691	64,729
Total assets	$ 2,164,419	2,238,319
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 5,951	6,227
Notes payable	1,961	2,175
Accounts payable	248,967	329,094
Withholdings and collections due governmental agencies	51,606	58,323
Other accrued liabilities	49,314	47,973
Income taxes	22,951	25,627
Total current liabilities	380,750	469,419
Notes payable	189,705	28,367
Nonrecourse debt of a subsidiary	143,768	177,486
Deferred income taxes	124,543	136,390
Reserve for dismantlement costs	154,686	153,021
Reserve for major repairs	43,519	43,038
Deferred credits and other liabilities	149,215	151,247
Stockholders' equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued	--	--
Common Stock, par $1.00, authorized 80,000,000 shares, issued 48,775,314 shares	48,775	48,775
Capital in excess of par value	510,116	509,615
Retained earnings	545,199	622,532
Accumulated other comprehensive income - foreign currency translation	(23,520)	891
Unamortized restricted stock awards	(2,361)	(944)
Treasury stock	(99,976)	(101,518)
Total stockholders' equity	978,233	1,079,351
Total liabilities and stockholders' equity	$ 2,164,419	2,238,319

See notes to consolidated financial statements, page F-6.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED DECEMBER 31 (THOUSANDS OF DOLLARS)	1998	1997	1996
OPERATING ACTIVITIES			
Income (loss) from continuing operations	$ (14,394)	132,406	125,956
Adjustments to reconcile above income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	202,695	209,419	182,381
Impairment of long-lived assets	80,127	28,056	--
Provisions for major repairs	20,420	24,614	24,797
Expenditures for major repairs and dismantlement costs	(24,582)	(14,393)	(10,839)
Exploratory expenditures charged against income	55,128	84,320	60,532
Amortization of undeveloped leases	10,454	10,472	9,674
Deferred and noncurrent income tax charges (credits)	(937)	25,992	28,464
Pretax gains from disposition of assets	(3,857)	(29,061)	(34,369)
Other - net	4,504	7,969	5,889
	329,558	479,794	392,485
(Increase) decrease in operating working capital other than cash and cash equivalents	(3,810)	(72,391)	77,111
Other adjustments related to continuing operations	(4,657)	(5,560)	2,884
Net cash provided by continuing operations	321,091	401,843	472,480
Net cash provided by discontinued operations	--	--	18,158
Net cash provided by operating activities	321,091	401,843	490,638
INVESTING ACTIVITIES			
Capital expenditures requiring cash	(388,799)	(468,031)	(418,056)
Proceeds from sale of property, plant and equipment	9,463	43,776	55,536
Other continuing operations - net	(1,767)	673	(1,128)
Investing activities of discontinued operations	--	--	(17,402)
Net cash required by investing activities	(381,103)	(423,582)	(381,050)
FINANCING ACTIVITIES			
Additions to notes payable	161,342	9,675	--
Reductions of notes payable	(218)	(4)	(776)
Additions to nonrecourse debt of a subsidiary	240	6,397	23,089
Reductions of nonrecourse debt of a subsidiary	(34,234)	(17,276)	(10,628)
Sale of treasury shares under employee stock purchase plan	552	192	--
Cash dividends paid	(62,939)	(60,573)	(58,294)
Net cash provided (required) by financing activities	64,743	(61,589)	(46,609)
Effect of exchange rate changes on cash and cash equivalents	(748)	(2,091)	2,277
Net increase (decrease) in cash and cash equivalents	3,983	(85,419)	65,256
Increase applicable to discontinued operations	--	--	(16,402)
Net increase (decrease) in cash and cash equivalents of continuing operations	3,983	(85,419)	48,854
Cash and cash equivalents of continuing operations at January 1	24,288	109,707	60,853
Cash and cash equivalents of continuing operations at December 31	$ 28,271	24,288	109,707

See notes to consolidated financial statements, page F-6.

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

YEARS ENDED DECEMBER 31 (THOUSANDS OF DOLLARS)	1998	1997	1996
CUMULATIVE PREFERRED STOCK - par $100, authorized 400,000 shares, none issued	$ --	--	--
COMMON STOCK - par $1.00, authorized 80,000,000 shares, issued 48,775,314 shares at beginning and end of year	48,775	48,775	48,775
CAPITAL IN EXCESS OF PAR VALUE			
Balance at beginning of year	509,615	509,008	507,758
Exercise of stock options	103	521	450
Restricted stock transactions	142	7	800
Sale of stock under employee stock purchase plan	256	79	--
Balance at end of year	510,116	509,615	509,008
RETAINED EARNINGS			
Balance at beginning of year	622,532	550,699	643,699
Net income (loss) for the year	(14,394)	132,406	137,855
Distribution of common stock of Deltic Timber Corporation to stockholders	--	--	(172,561)
Cash dividends - $1.40 a share in 1998, $1.35 a share in 1997 and $1.30 a share in 1996	(62,939)	(60,573)	(58,294)
Balance at end of year	545,199	622,532	550,699
ACCUMULATED OTHER COMPREHENSIVE INCOME - FOREIGN CURRENCY TRANSLATION			
Balance at beginning of year	891	22,573	4,568
Translation gains (losses) during the year	(24,411)	(21,682)	18,005
Balance at end of year	(23,520)	891	22,573
UNAMORTIZED RESTRICTED STOCK AWARDS			
Balance at beginning of year	(944)	(1,298)	(592)
Stock awards	(3,238)	--	(1,023)
Amortization, forfeitures and changes in price of Common Stock	1,821	354	317
Balance at end of year	(2,361)	(944)	(1,298)
TREASURY STOCK			
Balance at beginning of year	(101,518)	(102,279)	(103,063)
Exercise of stock options	110	526	543
Awarded restricted stock, net of forfeitures	1,136	122	241
Sale of stock under employee stock purchase plan	296	113	--
Balance at end of year - 3,824,838 shares of Common Stock in 1998, 3,883,883 shares in 1997 and 3,912,971 shares in 1996, at cost	(99,976)	(101,518)	(102,279)
TOTAL STOCKHOLDERS' EQUITY	$ 978,233	1,079,351	1,027,478

See notes to consolidated financial statements, page F-6.

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 crude oil operation, the world's largest, and operates two oil refineries in the United States and shares ownership in a U.K. refinery. Murphy markets petroleum products under various brand names and to unbranded wholesale customers in the United States, the United Kingdom, and Canada and transports and trades crude oil in Canada.

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.

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.

INVENTORIES - Inventories of crude oil and refined products 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.

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. Significant undeveloped leases are reviewed periodically and a valuation allowance is provided for any estimated decline in value. Cost of other undeveloped leases is expensed over the estimated average 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 long-lived assets are evaluated on a specific asset basis or in groups of similar assets, as applicable. An impairment is recognized when the undiscounted estimated future net cash flows of an evaluated asset are less than its carrying value.

Depreciation and depletion of producing oil and gas properties are provided based on units of production. Unit rates are computed for unamortized development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. Estimated dismantlement, abandonment and site restoration costs, net of salvage value, are considered in determining depreciation and depletion. Refining and marketing facilities are depreciated using the composite straight-line method. Other properties are depreciated by individual unit on the straight-line method.

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

Provisions for turnarounds of refineries and a synthetic oil upgrading facility are charged to expense monthly. Costs incurred are charged against the reserve. All other maintenance and repairs are expensed. Renewals and betterments are capitalized.

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 reserve. 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. U.K. petroleum revenue taxes are provided using the estimated effective tax rate over the life of applicable U.K. properties.

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 Income" 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 - The Company uses derivative instruments on a limited basis to manage certain risks related to interest rates, foreign currency exchange rates and commodity prices. Instruments that reduce the exposure of assets, liabilities or anticipated transactions to interest rate, currency or price risks are accounted for as hedges. Gains and losses on derivatives that cease to qualify as hedges are recognized in income or expense. 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 trading purposes, and it does not use derivatives with leveraged or complex features. Derivative instruments are traded either with creditworthy major financial institutions or over national exchanges. Net cash to be paid or received on an interest rate swap is recognized as an adjustment of "Interest Expense." If the Company terminates an interest rate swap prior to maturity, any cash paid or received as settlement would be deferred and recognized as an adjustment to "Interest Expense" over the shorter of the remaining life of the debt or the remaining contractual life of the swap. Gains or losses on foreign exchange contracts are recognized in income or as adjustments to the carrying amounts of hedged items. Gains or losses on settlement of crude oil swaps are included in costs in the periods that the hedged oil purchases occur. A loss is recognized if the estimated cost of the future crude oil purchases, including projected settlement costs of the swap contracts, exceeds the estimated net realizable value of the related finished products.

EXCISE TAXES ON REFINED PRODUCTS - Taxes collected on the sales of refined products and remitted to governmental agencies are not included in revenues or in costs and expenses.

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.

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

NOTE B - DISCONTINUED OPERATIONS

On December 31, 1996, Murphy completed a tax-free spin-off to its stockholders of all the common stock of its wholly owned farm, timber and real estate subsidiary, Deltic Farm & Timber Co., Inc. (reincorporated as "Deltic Timber Corporation"). The spin-off resulted in a net charge of $172,561,000 to "Retained Earnings" in 1996. Farm, timber and real estate activities have been accounted for as discontinued operations. Selected operating results for these activities, presented as a net amount in the Consolidated Statements of Income for 1996 were: revenues of $87,746,000; income tax provision of $8,878,000; income from operations of $13,999,000, $.31 a diluted share; and costs of spin-off transaction of $2,100,000, $(.04) a diluted share.

NOTE C - PROPERTY, PLANT AND EQUIPMENT

	INVESTMENT DECEMBER 31, 1998		INVESTMENT DECEMBER 31, 1997	
(THOUSANDS OF DOLLARS)	COST	NET	COST	NET
Exploration and production	$3,657,399	1,228,477*	3,476,167	1,235,373*
Refining	677,245	257,640	649,374	254,032
Marketing	196,362	116,958	178,179	104,305
Transportation	81,307	40,459	80,819	42,125
Corporate and other	35,903	18,828	34,104	20,003
	$4,648,216	1,662,362	4,418,643	1,655,838

*Includes $15,766 in 1998 and $17,084 in 1997 related to administrative assets and support equipment.

In 1998 and 1997, the Company recorded noncash charges of $80,127,000 and $28,056,000, respectively, for impairment of certain long-lived assets. After related income tax benefits, these write-downs reduced net income by $57,573,000 in 1998 and $16,224,000 in 1997. The 1998 charges resulted from management's expectation of a continuation of the low-price environment for sales of crude oil and natural gas that existed at the end of 1998; the write-down included certain oil and gas assets in the U.S. Gulf of Mexico, the U.K. North Sea, China, and Canada and certain marketing assets in Canada. The 1997 charges related to certain investments in Canadian heavy oil fields that were not adequately supported by reserves and three natural gas fields in the Gulf of Mexico that depleted earlier than anticipated. The carrying values for assets determined to be impaired were adjusted to estimated fair values based on projected future discounted net cash flows for such assets.

NOTE D - FINANCING ARRANGEMENTS

At December 31, 1998, the Company had a committed credit facility with a major banking consortium of an equivalent US $300,000,000 for a combination of U.S. dollar and Canadian dollar borrowings, of which an equivalent US $113,842,000 was outstanding and classified as long-term notes payable. In addition, the Company had committed facilities with major banks of US $117,220,000 subject to drawdown based on the availability of 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 certain of the commitments. The facilities expire at dates ranging from 1999 through 2002. At December 31, 1998 and 1997, U.S. dollar and Canadian dollar commercial paper and bankers' acceptances totaling an equivalent US $115,733,000 and US $118,834,000, respectively, supported by bank credit facilities, were classified as nonrecourse debt. In addition, the Company had uncommitted lines of credit with banks at December 31, 1998, totaling an equivalent US $191,911,000 for a combination of U.S. dollar and Canadian dollar borrowings. At December 31, 1998, an equivalent US $56,961,000 of debt was outstanding under these uncommitted lines, $55,000,000 of which is planned to be refinanced under an existing committed credit facility and is reflected as long-term notes payable.

At the end of 1998, the Company had a shelf registration on file with the U.S. Securities and Exchange Commission that would permit the offer and sale of $250,000,000 in debt securities. No securities had been issued as of December 31, 1998.

NOTE E - LONG-TERM DEBT

DECEMBER 31 (THOUSANDS OF DOLLARS)	1998	1997
Notes payable		
Notes payable to bank, 10.1%, due 2004	$ 20,000	20,000
Notes payable to banks, 5.30% to 5.35%, $7,842 payable in Canadian dollars, due 2002	168,842	7,500
Other, 6% and 8%, due 1999-2021	867	871
Total notes payable	189,709	28,371
Nonrecourse debt of a subsidiary		
Guaranteed credit facilities with banks		
Commercial paper, 4.98% to 5.28%, $40,386 payable in Canadian dollars, supported by credit facility, due 2001-2008	109,786	112,611
Bankers' acceptance, 5.27%, payable in Canadian dollars, supported by credit facility, due 1999	5,947	6,223
Loan payable to Canadian government, interest free, payable in Canadian dollars, due 1999-2008	33,982	36,358
Promissory note, 6.25%, payable in Canadian dollars, due 1998	--	28,517
Total nonrecourse debt of a subsidiary	149,715	183,709
Total including current maturities	339,424	212,080
Current maturities	(5,951)	(6,227)
Total long-term debt	$ 333,473	205,853

Amounts becoming due for the four years after 1999 are: $5,000 each in 2000 and 2001; $200,149,000 in 2002; and $13,795,000 in 2003.

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. The Company has borrowed the maximum amount available under the Primary Guarantee Facility at December 31, 1998. The amount guaranteed declines quarterly beginning in 2001, at which time repayment will begin based on the greater of 30% of Murphy's after-tax free cash flow from Hibernia or equal quarterly payments over eight years. The payment for 2001 is planned to be refinanced under an existing committed credit facility and is thereby reflected as becoming due in 2002. No guaranteed financing is available after January 1, 2016. A guarantee fee of .5% is payable annually in arrears to the Canadian government.

The interest free loan from the Canadian government was also used to finance expenditures for the Hibernia field. Repayment will begin in 1999, but payments through 2001 are planned to be refinanced under an existing committed credit facility and are thereby reflected as becoming due in 2002.

NOTE F - INCOME TAXES

The components of income (loss) from continuing operations before income taxes were:

(THOUSANDS OF DOLLARS)	1998	1997	1996
United States	$ 44,600	135,476	104,888
Foreign	(52,877)	76,174	111,467
	$ (8,277)	211,650	216,355

The components of income tax expense (benefit) were:

(THOUSANDS OF DOLLARS)	1998	1997	1996
Income tax expense (benefit)			
Continuing operations			
Federal - Current*	$ 6,431	31,278	16,445
Deferred	6,232	(1,751)	15,837
Noncurrent	3,785	14,946	8,762
	16,448	44,473	41,044
State - Current	2,021	4,589	2,816
Foreign - Current	(3,498)	12,912	46,130
Deferred	(10,201)	19,423	4,095
Noncurrent	1,347	(2,153)	(3,686)
	(12,352)	30,182	46,539
Total from continuing operations	6,117	79,244	90,399
Discontinued operations	--	--	8,878
Total income tax expense	$ 6,117	79,244	99,277

*Net of benefits of $12,537 in 1997 and $1,035 in 1996 for alternative minimum tax credits.

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 significant components of deferred income tax expense (benefit) attributable to income (loss) from continuing operations before income taxes for the three years ended December 31, 1998, were:

(THOUSANDS OF DOLLARS)	1998	1997	1996
Deferred tax expense (benefit) excluding the effects of the items below on deferred tax assets and liabilities	$ (1,901)	13,180	17,754
Estimated tax credit carryforward (increase) decrease	(2,068)	6,065	2,178
Effect of change in U.K. tax rate	--	(1,573)	--
Total deferred tax expense (benefit)	$ (3,969)	17,672	19,932

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

(THOUSANDS OF DOLLARS)	1998	1997	1996
Theoretical income tax expense (benefit) based on the U.S. statutory tax rate	$ (2,897)	74,078	75,724
Foreign asset impairment with no tax benefit	5,293	--	--
Foreign income subject to foreign taxes at greater than U.S. statutory rate	4,671	7,711	14,641
State income taxes	1,313	2,983	1,831
Refund and settlement of foreign taxes	(1,410)	(3,163)	(2,945)
Refund and settlement of U.S. taxes	(704)	--	--
Other, net	(149)	(2,365)	1,148
Total income tax expense from continuing operations	$ 6,117	79,244	90,399

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 1998 and 1997, showing the tax effects of significant temporary differences follows.

(THOUSANDS OF DOLLARS)	1998	1997
Deferred tax assets		
Property and leasehold costs	$ 75,716	76,516
Reserves for dismantlements and major repairs	63,763	64,206
Federal alternative minimum tax credit carryforward	2,068	--
Postretirement and other employee benefits	17,979	21,146
Other deferred tax assets	24,234	24,873
Total gross deferred tax assets	183,760	186,741
Less valuation allowance	(47,294)	(47,228)
Net deferred tax assets	136,466	139,513
Deferred tax liabilities		
Property, plant and equipment	(34,152)	(41,069)
Accumulated depreciation, depletion and amortization	(189,082)	(194,540)
Other deferred tax liabilities	(24,686)	(25,117)
Total gross deferred tax liabilities	(247,920)	(260,726)
Net deferred tax liabilities	$(111,454)	(121,213)

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 $66,000 in 1998 and $13,619,000 in 1997; the change in each year offset the change in certain deferred tax assets. Any subsequent reductions of the valuation allowance will be reported as reductions of income tax expense assuming no offsetting change in the deferred tax asset.

The Company has not recorded a deferred tax liability of $19,700,000 related to undistributed earnings of certain foreign subsidiaries at December 31, 1998, because the earnings are considered permanently invested.

Income tax returns are subject to audit by the U.S. Internal Revenue Service and other taxing authorities. In 1998, 1997 and 1996, the Company recorded benefits to income of $2,114,000, $3,163,000 and $5,120,000, respectively, from refunds and settlements of various U.S. and foreign tax issues primarily related to prior years. The Company believes that adequate accruals have been made for unsettled issues.

NOTE G - 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 .5% 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 options and restricted stock over the vesting/performance periods and adjusting costs for subsequent changes in fair market value of the shares. Compensation cost charged against (credited to) income for stock-based plans was $(4,646,000) in 1998, $2,026,000 in 1997 and $5,566,000 in 1996; outstanding awards were not significantly modified in the last three years. Had compensation cost of these stock-based plans been based on the fair value of the instruments at date of grant using the provisions of Statement of Financial Accounting Standards (SFAS) No. 123, "Accounting for Stock-Based Compensation," the Company's net income and earnings per share would be the pro forma amounts shown in the following table. The pro forma effects on net income in the table may not be representative of the pro forma effects on net income of future years because the SFAS No. 123 provisions used in these calculations were only applied to stock options and restricted stock granted after 1994.

(THOUSANDS OF DOLLARS EXCEPT PER SHARE DATA)		1998	1997	1996
Net income (loss) -	As reported	$ (14,394)	132,406	137,855
	Pro forma	(18,182)	132,089	138,570
Earnings per share -	As reported, basic	$ (.32)	2.95	3.07
	Pro forma, basic	(.40)	2.94	3.09
	As reported, diluted	(.32)	2.94	3.07
	Pro forma, diluted	(.40)	2.94	3.09

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 FMV at date of grant, except for certain 1997 grants with option prices above FMV. One-half of each grant may be exercised after two years and the remainder after three years. At exercise, a grantee may pay cash for shares, or alternatively, not remit cash and receive shares equal to the inherent value of options exercised on that date. The number of outstanding options at January 1, 1997, and the related option prices were adjusted to preserve the existing economic values of the options at the time of the Deltic spin-off.

The pro forma net income calculations in the preceding table reflect the following weighted-average fair values of options granted in 1998, 1997 and 1996; fair values of options have been estimated by using the Black-Scholes pricing model and the assumptions as shown.

	1998 FMV	1997 Above FMV	1997 FMV	1996 FMV
Weighted-average fair value per share at grant date	$ 9.01	8.25	9.75	7.27
Weighted-average assumptions				
Dividend yield	2.91%	3.00%	3.00%	3.20%
Expected volatility	17.27%	17.37%	17.37%	17.64%
Risk-free interest rate	5.46%	6.37%	6.18%	5.26%
Expected life	5 yrs.	7 yrs.	5 yrs.	5 yrs.

Changes in options outstanding, including shares issued under a prior plan, were:

	NUMBER OF SHARES	AVERAGE EXERCISE PRICE
Outstanding at December 31, 1995	425,230	$ 39.28
Granted at FMV	168,000	42.44
Exercised	(105,006)	36.47
Forfeited	(47,625)	42.82
Outstanding at December 31, 1996	440,599	40.77
Deltic spin-off adjustment	17,407	--
Granted at FMV	180,250	50.38
Granted above FMV	231,750	60.45
Exercised	(68,022)	36.53
Forfeited	(31,295)	49.08
Outstanding at December 31, 1997	770,689	48.04
Granted at FMV	312,000	49.75
Exercised	(17,400)	36.04
Forfeited	(12,040)	49.34
Outstanding at December 31, 1998	1,053,249	48.73
Exercisable at December 31, 1996	153,223	$ 36.92
Exercisable at December 31, 1997	174,269	37.79
Exercisable at December 31, 1998	284,529	39.53

Additional information about stock options outstanding at December 31, 1998, is shown below.

	OPTIONS OUTSTANDING			OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICES	NO. OF OPTIONS	AVG. LIFE IN YEARS	AVG. PRICE	NO. OF OPTIONS	AVG. PRICE
$30.29 to $39.42	109,289	3.6	$ 36.10	109,289	$ 36.10
$40.81 to $42.25	245,960	6.6	41.43	175,240	41.68
$49.75 to $50.38	477,500	8.7	49.97	--	--
$55.41 to $65.49	220,500	8.1	60.45	--	--
Total outstanding	1,053,249	7.6	48.73	284,529	39.53

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 - Since 1992, shares of restricted stock have been granted in alternate 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 may vote and receive dividends on the 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. For the pro forma net income calculation, the fair values per share of restricted stock granted in 1998 and 1996 were $49.50 and $42.88, the respective market prices of the stock at the dates granted. On December 31, 1996, 50% of eligible shares granted in 1992 were awarded and the remaining shares were forfeited based on financial objectives achieved. The number of restricted shares outstanding at January 1, 1997, was adjusted to preserve the existing economic value of the stock at the time of the Deltic spin-off. On December 31, 1998, all shares granted in 1994 were forfeited because financial objectives were not achieved. Changes in restricted stock outstanding were:

(NUMBER OF SHARES)	1998	1997	1996
Balance at beginning of year	39,856	36,512	38,011
Granted	59,750	--	24,250
Grant adjustment to reflect Deltic spin-off	--	5,977	--
Awarded	--	(1,336)*	(10,563)
Forfeited	(16,242)	(1,297)	(15,186)
Balance at end of year	83,364	39,856	36,512

*Additional shares awarded related to Deltic spin-off.

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 $518,000, $3,894,000 and $3,100,000 was recorded in 1998, 1997 and 1996, respectively, for these plans.

EMPLOYEE STOCK PURCHASE PLAN (ESPP) - In 1997, the Company's shareholders approved the ESPP, under which 50,000 shares of the Company's Common Stock could be purchased by employees. Each quarter, an eligible U.S. 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 50,000 shares or June 30, 2002. Employee stock purchases under the ESPP were 11,315 shares at an average price of $48.81 a share in 1998 and 4,326 shares at $44.44 in 1997. At December 31, 1998, 34,359 shares remained available for sale under the ESPP. Compensation costs related to the ESPP were immaterial.

NOTE H - EMPLOYEE AND RETIREE BENEFIT PLANS

PENSION AND POSTRETIREMENT PLANS - The Company has noncontributory defined benefit pension plans that cover substantially all full-time employees. In addition, the Company sponsors plans that provide health care and life insurance benefits for 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, 1998 and 1997, and a statement of the funded status as of December 31, 1998 and 1997.

	PENSION BENEFITS		POSTRETIREMENT BENEFITS	
(THOUSANDS OF DOLLARS)	1998	1997	1998	1997
CHANGE IN BENEFIT OBLIGATION				
Obligation at January 1	$ 220,981	193,923	36,255	34,228
Service cost	5,242	4,517	601	508
Interest cost	15,309	14,889	2,474	2,466
Plan amendments	2,744	1,046	--	--
Participant contributions	--	--	535	561
Actuarial loss	8,492	20,612	496	1,938
Exchange rate changes	(908)	(1,081)	--	--
Benefits paid	(13,838)	(12,925)	(3,612)	(3,446)
Obligation at December 31	238,022	220,981	36,749	36,255
CHANGE IN PLAN ASSETS				
Fair value of plan assets at January 1	269,794	230,290	--	--
Actual return on plan assets	30,727	52,992	--	--
Employer contributions	1,373	912	3,077	2,885
Participant contributions	--	--	535	561
Exchange rate changes	(1,210)	(1,475)	--	--
Benefits paid	(13,838)	(12,925)	(3,612)	(3,446)
Fair value of plan assets at December 31	286,846	269,794	--	--
RECONCILIATION OF FUNDED STATUS				
Funded status at December 31	48,824	48,813	(36,749)	(36,255)
Unrecognized actuarial (gain) loss	(30,410)	(31,296)	6,730	6,428
Unrecognized transition asset	(10,960)	(13,339)	--	--
Unrecognized prior service cost	6,813	4,668	--	--
Net plan asset (liability) recognized	$ 14,267	8,846	(30,019)	(29,827)
AMOUNTS RECOGNIZED IN THE CONSOLIDATED BALANCE SHEETS AT DECEMBER 31				
Prepaid benefit asset	$ 29,477	24,311	--	--
Accrued benefit liability	(16,087)	(15,983)	(30,019)	(29,827)
Intangible asset	877	518	--	--
Net plan asset (liability) recognized	$ 14,267	8,846	(30,019)	(29,827)

The Company's U.S. and Canadian nonqualified and U.S. directors' retirement plans were the only pension plans with accumulated benefit obligations in excess of plan assets at December 31, 1998 and 1997. The plans' accumulated benefit obligations at December 31, 1998 and 1997, were $7,486,000 and $6,381,000, respectively; there were no assets in these plans. The Company's postretirement benefit plan also had no plan assets; the benefit obligation for this plan at December 31, 1998 and 1997, was $30,019,000 and $29,827,000, respectively.

The table that follows provides the components of net periodic benefit expense (credit) for the three years ended December 31, 1998.

	PENSION BENEFITS			POSTRETIREMENT BENEFITS		
(THOUSANDS OF DOLLARS)	1998	1997	1996	1998	1997	1996
Service cost	$ 5,242	4,517	4,719	601	508	714
Interest cost	15,309	14,889	14,229	2,474	2,466	2,175
Expected return on plan assets	(22,180)	(19,040)	(18,361)	--	--	--
Amortization of prior service cost	626	402	354	--	--	--
Amortization of transitional asset	(2,211)	(2,216)	(2,260)	--	--	--
Recognized actuarial (gain) loss	(758)	(965)	(736)	194	67	17
Net periodic benefit expense (credit)	$ (3,972)	(2,413)	(2,055)	3,269	3,041	2,906

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

	PENSION BENEFITS		POSTRETIREMENT BENEFITS	
(THOUSANDS OF DOLLARS)	1998	1997	1998	1997
Obligation at December 31	$47,625	42,871	--	--
Fair value of plan assets at December 31	54,348	49,014	--	--
Net plan liability recognized	(3,285)	(3,361)	--	--
Net periodic benefit expense	410	23	--	--

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 1998 and 1997.

	PENSION BENEFITS		POSTRETIREMENT BENEFITS	
	1998	1997	1998	1997
Discount rate	6.62%	7.03%	6.75%	7.00%
Expected return on plan assets	8.31%	8.43%	--	--
Rate of compensation increase	4.67%	4.81%	--	--

For purposes of measuring postretirement benefit obligations, a 7.5% annual rate of increase in the cost of health care was assumed at December 31, 1998 and 1997. The rate of increase was assumed to decrease gradually each year to a rate of 4.5% for 2002 and beyond.

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, 1998	$ 224	(213)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 1998	2,394	(2,327)

THRIFT PLANS - Most U.S. and Canadian employees of the Company may participate in thrift 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. Company contributions to these plans were $3,333,000 in 1998, $3,076,000 in 1997 and $2,784,000 in 1996, including $190,000 in 1996 that was included in "Discontinued Farm, Timber and Real Estate Operations" in the Consolidated Statements of Income.

NOTE I - FINANCIAL INSTRUMENTS

DERIVATIVE INSTRUMENTS - As discussed in Note A, Murphy utilizes derivative instruments on a limited basis to manage risks related to interest rates, foreign currency exchange rates and commodity prices. At December 31, 1998 and 1997, the Company had interest rate swap agreements with notional amounts totaling $100,000,000 that serve to convert an equal amount of variable rate long-term debt to fixed rates. The swaps mature in 2002 and 2004. The swaps require Murphy to pay a weighted-average interest rate of 6.46% over their composite lives and to receive a variable rate, which averaged 5.23% at December 31, 1998. Using the accrual/settlement method of accounting, the Company records the net amount to be received or paid under the swap agreements as part of "Interest Expense" in the Consolidated Statements of Income.

At December 31, 1997, the Company had a forward foreign currency exchange contract that served to fix the U.S. dollar cost for Canadian dollar nonrecourse debt associated with the Company's investment in the Syncrude project. The currency exchange contract matured and the related debt was retired in December 1998. During the life of the contract, the Company recorded the unrealized difference between the contract exchange rate and the actual exchange rate on the Consolidated Balance Sheet as an adjustment to "Nonrecourse Debt of a Subsidiary," with the offset to "Accumulated Other Comprehensive Income."

The Company previously used crude oil swap agreements to reduce a portion of the financial exposure of its U.S. refineries to crude oil price movements. Unrealized gains or losses on such swap contracts were generally deferred and recognized in connection with the associated crude oil purchase. If conditions indicated that the market price of finished products would not allow for recovery of the costs of the finished products, including any unrealized loss on the crude oil swap, a liability was provided for the nonrecoverable portion of the unrealized swap loss. The final swap matured in 1997. The Company recorded pretax operating results associated with crude oil swaps in "Crude Oil, Products and Related Operating Expenses" in the Consolidated Statements of Income. For 1997 and 1996, after-tax gains from crude oil swaps were $5,041,000 and $9,209,000, respectively.

FAIR VALUE - The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 1998 and 1997. 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.

(THOUSANDS OF DOLLARS)	1998 CARRYING AMOUNT	1998 ESTIMATED FAIR VALUE	1997 CARRYING AMOUNT	1997 ESTIMATED FAIR VALUE
FINANCIAL LIABILITIES				
Current and long-term debt	$(341,385)	(333,905)	(214,255)	(205,240)
OFF-BALANCE-SHEET EXPOSURES				
Interest rate swaps	--	(5,453)	--	(1,886)
Financial guarantees and letters of credit	--	--	--	--

The carrying amounts of financial liabilities in the preceding table are included in the Consolidated Balance Sheets under "Current Maturities of Long-Term Debt," "Notes Payable," and "Nonrecourse Debt of a Subsidiary." The following methods and assumptions were used to estimate the fair value of each class of financial instruments shown in the table.

- Current and long-term debt - The fair value is estimated based on current rates offered the Company for debt of the same maturities.

- Interest rate swaps - The fair value is an estimate of the amounts, based on quotes from counterparties, that the Company would pay at the reporting date to cancel the contracts.

- Financial guarantees and letters of credit - The fair value, which represents fees associated with obtaining the instruments, was nominal.

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; this 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 transactions are major financial institutions.

NOTE J - 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 between the Company and Harris Trust Company of New York, as Rights Agent.

NOTE K - EARNINGS PER SHARE

A reconciliation of the weighted-average shares outstanding for computation of basic and diluted income (loss) per Common share for the three years ended December 31, 1998 follows. No difference existed between net income (loss) used in computing basic and diluted income (loss) per Common share for these years.

(WEIGHTED-AVERAGE SHARES OUTSTANDING)	1998	1997	1996
Basic method	44,955,679	44,881,225	44,858,115
Dilutive stock options	--	79,682	46,521
Diluted method	44,955,679	44,960,907	44,904,636

Stock options to acquire 1,053,249 shares in 1998, 346,306 shares in 1997 and 140,692 shares in 1996 were not considered in the computation of diluted earnings per share because the effects of these options would have improved the Company's earnings per share.

NOTE L - OTHER FINANCIAL INFORMATION

INVENTORIES - At December 31, 1998, the Company wrote down certain crude oil inventories to market value, resulting in a charge to income of $6,792,000 ($4,227,000 after tax). After the write-down, inventories accounted for under the LIFO method totaled $65,107,000 and $82,709,000 at December 31, 1998 and 1997, respectively, which were $14,695,000 and $76,008,000 less than such inventories would have been valued using the FIFO method.

FOREIGN CURRENCY - Cumulative translation gains and losses, net of insignificant related income tax effects, are included in "Accumulated Other Comprehensive Income" in the Consolidated Balance Sheets. At December 31, 1998, components of the net cumulative loss of $23,520,000 were gains (losses) of $37,535,000 for pounds sterling, $(61,884,000) for Canadian dollars and $829,000 for other currencies. Comparability of net income was not significantly affected by exchange rate fluctuations in 1998, 1997 or 1996. Net gains (losses) from foreign currency transactions included in the Consolidated Statements of Income were $282,000 in 1998, $200,000 in 1997 and $(175,000) in 1996.

CASH FLOW DISCLOSURES - Cash income taxes paid, net of refunds, were $26,227,000, $86,962,000 and $51,983,000 in 1998, 1997 and 1996. Interest paid, net of amounts capitalized, was $9,551,000, $269,000 and $1,659,000 in 1998, 1997 and 1996.

Changes in noncash operating working capital for the three years ended December 31, 1998, were:

(THOUSANDS OF DOLLARS)	1998	1997	1996
Accounts receivable	$ 38,541	47,214	(89,453)
Inventories	28,639	(27,061)	22,558
Prepaid expenses	15,031	(17,503)	(1,679)
Deferred income tax assets	2,158	4,348	(2,234)
Accounts payable and accrued liabilities	(85,503)	(67,623)	131,774
Current income tax liabilities	(2,676)	(11,766)	16,145
Net (increase) decrease in noncash operating working capital	$ (3,810)	(72,391)	77,111

NOTE M - COMMITMENTS

The Company leases land, service stations and other facilities under operating leases. Future minimum rental commitments under noncancellable operating leases are not material. Commitments for capital expenditures were approximately $209,000,000 at December 31, 1998, including $90,000,000 related to one third of a multiyear contract for a semisubmersible drilling rig capable of drilling in 6,000 feet of water. Delivery of the rig is scheduled for 1999.

NOTE N - 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; restrictions on production; 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; 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.

FOREIGN CRUDE OIL CONTRACTS - In August 1996, the Ecuadoran government notified the Company that its risk service contract for production of crude oil in Ecuador would be replaced by a production sharing contract effective January 1, 1997, to give the government a larger share of future oil revenues. While the state oil company, PetroEcuador, acknowledged that amounts were owed under the former contract and indicated its intention to pay, the Company considered the circumstances surrounding the contract replacement and recorded an $8,876,000 provision for doubtful accounts at December 31, 1996. Based on amounts subsequently collected, the Company determined that portions of the allowance for doubtful accounts were no longer required and recognized income of $2,410,000 in 1998 and $1,642,000 in 1997. Any collections of the remaining $4,824,000 receivable will be recognized as income when received.

In 1996, the Company negotiated a settlement of abandonment obligations with other joint owners of former oil properties in Gabon. As a result of this settlement, the Company recorded a net gain of $8,201,000 in 1996 to adjust for the dismantlement reserve no longer required.

ENVIRONMENTAL MATTERS AND YEAR 2000 ISSUES - The Company's environmental and Year 2000 contingencies are reviewed in Management's Discussion and Analysis of Financial Condition and Results of Operations under the sections entitled "Environmental" and "Year 2000 Issues" on pages 15 through 17 of this Form 10-K report.

OTHER MATTERS - The Company and its subsidiaries are engaged in a number of legal proceedings, all of which the Company considers routine and incidental to its business and none of which is considered material. In the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide letters of credit that may be drawn upon if the Company fails to perform under those contracts. At December 31, 1998, the Company had contingent liabilities of $13,700,000 on outstanding letters of credit and $25,400,000 under certain financial guarantees.

NOTE O - 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, and all other countries; each of these segments derives revenues primarily from the sale of crude oil and natural gas. The refining, marketing and transportation segments in the United States and the United Kingdom derive revenues mainly from the sale of petroleum products; the Canadian segment derives revenues primarily from the transportation and trading of crude oil. The Company's management evaluates segment performance based on income from continuing operations, excluding interest income and interest expense. Intersegment transfers of crude oil 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 $831,385,000, $679,953,000 and $550,116,000 for the years 1998, 1997 and 1996, 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. Murphy's equity method investments are in companies that transport crude oil and petroleum products. Corporate and other activities, including interest income, miscellaneous gains (losses), interest expense and unallocated overhead, are shown in the tables to reconcile the business segments to consolidated totals. As used in the tables, "Certain Long-Lived Assets at December 31" exclude investments, noncurrent receivables and deferred tax assets.

SEGMENT INFORMATION (CONTINUED ON PAGE F-21)

	EXPLORATION AND PRODUCTION					
(MILLIONS OF DOLLARS)	U.S.	CANADA	U.K.	ECUADOR	OTHER	TOTAL
YEAR ENDED DECEMBER 31, 1998						
Segment income (loss)	$ .7	(7.5)	(13.3)	4.8	(35.1)	(50.4)
Revenues from external customers	146.7	92.5	82.8	21.3	2.7	346.0
Intersegment revenues	32.4	42.5	12.3	--	--	87.2
Interest income	--	--	--	--	--	--
Interest expense, net of capitalization	--	--	--	--	--	--
Income of equity companies	--	--	--	--	--	--
Income tax expense (benefit)	(.1)	(11.3)	(1.6)	(.8)	.1	(13.7)
Significant noncash charges (credits)						
Depreciation, depletion, amortization	66.0	44.0	42.9	10.2	--	163.1
Impairment of long-lived assets	29.9	10.1	24.3	--	15.1	79.4
Provisions for major repairs	--	3.1	--	--	--	3.1
Amortization of undeveloped leases	6.7	3.8	--	--	--	10.5
Deferred and noncurrent income taxes	(3.3)	(6.3)	(4.3)	--	.7	(13.2)
Additions to property, plant, equipment	104.0	94.1	67.5	10.2	.7	276.5
Total assets at year-end	399.1	595.6	317.6	60.3	13.3	1,385.9
YEAR ENDED DECEMBER 31, 1997						
Segment income (loss)	$ 51.6	19.0	16.3	14.5	(16.3)	85.1
Revenues from external customers	210.7	125.1	121.6	36.0	2.5	495.9
Intersegment revenues	64.1	60.5	--	--	--	124.6
Interest income	--	--	--	--	--	--
Interest expense, net of capitalization	--	--	--	--	--	--
Income of equity companies	--	--	--	--	--	--
Income tax expense (benefit)	27.2	9.8	15.4	(1.1)	.1	51.4
Significant noncash charges (credits)						
Depreciation, depletion, amortization	79.4	37.9	43.7	11.4	--	172.4
Impairment of long-lived assets	7.7	20.4	--	--	--	28.1
Provisions for major repairs	--	4.6	--	--	--	4.6
Amortization of undeveloped leases	6.7	3.6	.1	--	.1	10.5
Deferred and noncurrent income taxes	(9.8)	9.1	(.9)	--	1.3	(.3)
Additions to property, plant, equipment	102.5	135.1	80.0	10.4	10.9	338.9
Total assets at year-end	400.7	596.0	319.6	61.5	24.9	1,402.7
YEAR ENDED DECEMBER 31, 1996						
Segment income (loss)	$ 68.1	32.7	14.7	5.0	3.5	124.0
Revenues from external customers	193.4	65.0	96.6	35.0	8.8	398.8
Intersegment revenues	71.8	102.2	34.4	--	--	208.4
Interest income	--	--	--	--	--	--
Interest expense, net of capitalization	--	--	--	--	--	--
Income of equity companies	--	--	--	--	--	--
Income tax expense (benefit)	37.1	18.8	24.3	1.2	.4	81.8
Significant noncash charges (credits)						
Depreciation, depletion, amortization	60.5	30.8	40.8	8.9	6.6	147.6
Provisions for major repairs	--	4.4	--	--	--	4.4
Amortization of undeveloped leases	6.5	3.0	.1	--	.1	9.7
Deferred and noncurrent income taxes	15.3	2.8	(3.4)	--	(.7)	14.0
Additions to property, plant, equipment	149.8	91.6	55.9	11.7	4.5	313.5
Total assets at year-end	401.0	552.7	307.0	72.5	14.2	1,347.4

GEOGRAPHIC INFORMATION

	CERTAIN LONG-LIVED ASSETS AT DECEMBER 31					
(MILLIONS OF DOLLARS)	U.S.	CANADA	U.K.	ECUADOR	OTHER	TOTAL
1998	$ 706.2	600.4	352.8	54.4	8.4	1,722.2
1997	683.8	601.4	354.5	54.4	21.7	1,715.8
1996	668.1	560.1	331.7	55.4	12.1	1,627.4

SEGMENT INFORMATION (CONTINUED FROM PAGE F-20)

(MILLIONS OF DOLLARS)	REFINING, MARKETING & TRANSPORTATION U.S.	U.K.	CANADA	TOTAL	CORP. & OTHER	CONSOLI-DATED
YEAR ENDED DECEMBER 31, 1998						
Segment income (loss)	$ 27.7	17.3	2.5	47.5	(11.5)	(14.4)
Revenues from external customers	1,064.9	260.7	22.8	1,348.4	4.4	1,698.8
Intersegment revenues	3.1	--	.3	3.4	--	90.6
Interest income	--	--	--	--	4.0	4.0
Interest expense, net of capitalization	--	--	--	--	10.5	10.5
Income of equity companies	.8	--	--	.8	--	.8
Income tax expense (benefit)	15.7	7.9	3.1	26.7	(6.9)	6.1
Significant noncash charges (credits)						
Depreciation, depletion, amortization	29.3	5.2	1.9	36.4	3.2	202.7
Impairment of long-lived assets	--	--	.7	.7	--	80.1
Provisions for major repairs	15.2	2.0	--	17.2	.1	20.4
Amortization of undeveloped leases	--	--	--	--	--	10.5
Deferred and noncurrent income taxes	2.9	.6	(.3)	3.2	9.1	(.9)
Additions to property, plant, equipment	45.6	6.8	2.6	55.0	2.2	333.7
Total assets at year-end	465.5	160.8	50.2	676.5	102.0	2,164.4
YEAR ENDED DECEMBER 31, 1997						
Segment income (loss)	$ 41.3	9.2	6.2	56.7	(9.4)	132.4
Revenues from external customers	1,342.8	268.6	26.1	1,637.5	4.4	2,137.8
Intersegment revenues	2.4	--	.1	2.5	--	127.1
Interest income	--	--	--	--	4.8	4.8
Interest expense, net of capitalization	--	--	--	--	.6	.6
Income of equity companies	1.1	--	--	1.1	--	1.1
Income tax expense (benefit)	23.7	5.9	6.2	35.8	(8.0)	79.2
Significant noncash charges (credits)						
Depreciation, depletion, amortization	27.8	4.7	2.0	34.5	2.5	209.4
Impairment of long-lived assets	--	--	--	--	--	28.1
Provisions for major repairs	18.1	1.8	--	19.9	.1	24.6
Amortization of undeveloped leases	--	--	--	--	--	10.5
Deferred and noncurrent income taxes	(.7)	1.9	.1	1.3	25.0	26.0
Additions to property, plant, equipment	29.2	3.7	4.6	37.5	7.3	383.7
Total assets at year-end	491.4	194.7	64.5	750.6	85.0	2,238.3
YEAR ENDED DECEMBER 31, 1996						
Segment income (loss)	$ 1.8	6.2	6.1	14.1	(12.1)	126.0
Revenues from external customers	1,268.3	318.0	24.6	1,610.9	12.5	2,022.2
Intersegment revenues	2.5	--	.5	3.0	--	211.4
Interest income	--	--	--	--	12.6	12.6
Interest expense, net of capitalization	--	--	--	--	2.9	2.9
Income of equity companies	1.3	--	--	1.3	--	1.3
Income tax expense (benefit)	1.3	3.4	5.8	10.5	(1.9)	90.4
Significant noncash charges (credits)						
Depreciation, depletion, amortization	26.5	3.8	1.6	31.9	2.9	182.4
Provisions for major repairs	19.1	1.2	--	20.3	.1	24.8
Amortization of undeveloped leases	--	--	--	--	--	9.7
Deferred and noncurrent income taxes	2.6	3.5	--	6.1	8.4	28.5
Additions to property, plant, equipment	21.0	13.5	8.4	42.9	1.1	357.5
Total assets at year-end	506.8	151.8	83.5	742.1	154.3	2,243.8

GEOGRAPHIC INFORMATION

(MILLIONS OF DOLLARS)	REVENUES FROM EXTERNAL CUSTOMERS FOR THE YEAR U.S.	U.K.	CANADA	ECUADOR	OTHER	TOTAL
1998	$ 1,212.0	346.9	115.9	21.3	2.7	1,698.8
1997	1,554.7	392.9	151.7	36.0	2.5	2,137.8
1996	1,471.2	417.4	89.8	35.0	8.8	2,022.2

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 and natural gas 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.

Synthetic oil reserves in Canada are attributable to Murphy's share, after deducting estimated net profit royalty, of the Syncrude project, and include currently producing leases and the approved development of the Aurora mine. Additional reserves will be added as development progresses.

The Company has no proved reserves attributable to either long-term supply agreements with foreign governments or investees accounted for by the equity method.

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 special items that are reviewed in Management's Discussion and Analysis of Financial Condition and Results of Operations on page 9 of this Form 10-K report, and should be considered in conjunction with the Company's overall performance.

SCHEDULE 6 - 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 crude oil prices used for this calculation at December 31, 1998, were $9.50 a barrel for the United States, $9.67 for Canadian light, $6.16 for Canadian heavy, $9.77 for Canadian offshore, $10.46 for the United Kingdom and $5.20 for Ecuador. Average natural gas prices were $2.06 an MCF for the United States, $1.65 for Canada and $2.18 for the United Kingdom. Oil prices declined sharply during 1998 and remain depressed in early 1999, while U.S. natural gas sales prices began a sharp decline in early 1999.

Schedule 6 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, 1998.

SCHEDULE 1 - ESTIMATED NET PROVED OIL RESERVES

(MILLIONS OF BARRELS)	CRUDE OIL, CONDENSATE AND NATURAL GAS LIQUIDS UNITED STATES	CANADA*	UNITED KINGDOM	ECUADOR	TOTAL	SYNTHETIC OIL - CANADA	TOTAL
PROVED							
December 31, 1995	24.6	36.3	40.0	29.6	130.5	96.2	226.7
Revisions of previous estimates	.5	.6	.2	--	1.3	3.2	4.5
Extensions and discoveries	4.0	3.8	14.6	--	22.4	--	22.4
Production	(4.3)	(5.2)	(4.8)	(2.2)	(16.5)	(3.0)	(19.5)
Sales	(6.1)	(.3)	--	--	(6.4)	--	(6.4)
December 31, 1996	18.7	35.2	50.0	27.4	131.3	96.4	227.7
Revisions of previous estimates	1.6	(.4)	6.1	6.6	13.9	10.5	24.4
Improved recovery	--	.5	--	--	.5	--	.5
Purchases	.2	2.1	--	--	2.3	--	2.3
Extensions and discoveries	2.5	18.8	6.2	--	27.5	--	27.5
Production	(3.9)	(5.8)	(5.0)	(2.9)	(17.6)	(3.4)	(21.0)
Sales	--	(1.3)	--	--	(1.3)	--	(1.3)
December 31, 1997	19.1	49.1	57.3	31.1	156.6	103.5	260.1
Revisions of previous estimates	(1.0)	6.7	5.0	2.6	13.3	15.9	29.2
Purchases	--	1.3	--	--	1.3	--	1.3
Extensions and discoveries	8.0	.3	--	1.3	9.6	--	9.6
Production	(2.8)	(6.5)	(5.6)	(2.8)	(17.7)	(3.8)	(21.5)
Sales	(.3)	(.1)	--	--	(.4)	--	(.4)
December 31, 1998	23.0	50.8	56.7	32.2	162.7	115.6	278.3
PROVED DEVELOPED							
December 31, 1995	21.3	22.4	19.5	7.8	71.0	69.9	140.9
December 31, 1996	16.3	21.4	16.8	10.1	64.6	66.9	131.5
December 31, 1997	15.3	22.5	18.3	20.6	76.7	70.4	147.1
December 31, 1998	14.5	27.9	31.5	21.0	94.9	67.1	162.0

*Excludes 48.3 million barrels of crude oil to be added to reserves as development of the Hibernia and Terra Nova oil fields proceeds.

SCHEDULE 2 - ESTIMATED NET PROVED NATURAL GAS RESERVES

(BILLIONS OF CUBIC FEET)	UNITED STATES	CANADA	UNITED KINGDOM	SPAIN	TOTAL
PROVED					
December 31, 1995	431.5	160.1	47.4	3.8	642.8
Revisions of previous estimates	19.8	(5.1)	2.1	(1.2)	15.6
Extensions and discoveries	85.0	15.6	--	--	100.6
Production	(58.3)	(15.8)	(5.6)	(2.6)	(82.3)
Sales	(13.6)	(3.7)	--	--	(17.3)
December 31, 1996	464.4	151.1	43.9	--	659.4
Revisions of previous estimates	(23.7)	(4.9)	(2.9)	--	(31.5)
Purchases	11.1	.4	--	--	11.5
Extensions and discoveries	63.2	17.0	--	--	80.2
Production	(79.4)	(16.4)	(4.6)	--	(100.4)
Sales	(.2)	(6.8)	--	--	(7.0)
December 31, 1997	435.4	140.4	36.4	--	612.2
Revisions of previous estimates	(14.3)	(.2)	7.2	--	(7.3)
Purchases	--	6.3	--	--	6.3
Extensions and discoveries	80.9	2.6	--	--	83.5
Production	(61.9)	(17.9)	(4.5)	--	(84.3)
Sales	--	(1.1)	--	--	(1.1)
December 31, 1998	440.1	130.1	39.1	--	609.3
PROVED DEVELOPED					
December 31, 1995	229.0	150.0	27.6	3.8	410.4
December 31, 1996	291.1	146.0	25.4	--	462.5
December 31, 1997	304.2	135.2	24.0	--	463.4
December 31, 1998	291.8	120.3	29.9	--	442.0

SCHEDULE 3 - COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES

(MILLIONS OF DOLLARS)	UNITED STATES	CANADA	UNITED KINGDOM	ECUADOR	OTHER	SUBTOTAL	SYNTHETIC OIL - CANADA	TOTAL
YEAR ENDED DECEMBER 31, 1998								
Property acquisition costs								
Unproved	$ 14.1	2.7	.2	--	--	17.0	--	17.0
Proved	3.8	1.1	--	--	--	4.9	--	4.9
Total acquisition costs	17.9	3.8	.2	--	--	21.9	--	21.9
Exploration costs	77.6	18.3	2.6	--	21.9	120.4	--	120.4
Development costs	25.1	69.4	68.2	10.2	--	172.9	16.4	189.3
Total capital expenditures	120.6	91.5	71.0	10.2	21.9	315.2	16.4	331.6
Charged to expense								
Dry hole expense	10.8	8.9	(.4)	--	12.2	31.5	--	31.5
Geophysical and other costs	5.8	4.9	3.9	--	9.0	23.6	--	23.6
Total charged to expense	16.6	13.8	3.5	--	21.2	55.1	--	55.1
Expenditures capitalized	$ 104.0	77.7	67.5	10.2	.7	260.1	16.4	276.5
YEAR ENDED DECEMBER 31, 1997								
Property acquisition costs								
Unproved	$ 20.5	5.9	.2	--	--	26.6	--	26.6
Proved	8.2	13.9	.1	--	--	22.2	--	22.2
Total acquisition costs	28.7	19.8	.3	--	--	48.8	--	48.8
Exploration costs	74.4	18.2	14.6	--	28.1	135.3	--	135.3
Development costs	43.9	96.0	76.0	10.4	--	226.3	12.8	239.1
Total capital expenditures	147.0	134.0	90.9	10.4	28.1	410.4	12.8	423.2
Charged to expense								
Dry hole expense	30.9	4.5	5.7	--	7.2	48.3	--	48.3
Geophysical and other costs	13.6	7.2	5.2	--	10.0	36.0	--	36.0
Total charged to expense	44.5	11.7	10.9	--	17.2	84.3	--	84.3
Expenditures capitalized	$ 102.5	122.3	80.0	10.4	10.9	326.1	12.8	338.9
YEAR ENDED DECEMBER 31, 1996								
Property acquisition costs								
Unproved	$ 16.9	5.7	--	--	--	22.6	--	22.6
Proved	--	--	--	--	--	--	--	--
Total acquisition costs	16.9	5.7	--	--	--	22.6	--	22.6
Exploration costs	107.7	10.3	13.2	--	8.9	140.1	--	140.1
Development costs	60.1	75.7	56.1	11.7	--	203.6	7.7	211.3
Total capital expenditures	184.7	91.7	69.3	11.7	8.9	366.3	7.7	374.0
Charged to expense								
Dry hole expense	17.3	1.7	9.5	--	--	28.5	--	28.5
Geophysical and other costs	17.6	6.1	3.9	--	4.4	32.0	--	32.0
Total charged to expense	34.9	7.8	13.4	--	4.4	60.5	--	60.5
Expenditures capitalized	$ 149.8	83.9	55.9	11.7	4.5	305.8	7.7	313.5

SCHEDULE 4 - RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

(MILLIONS OF DOLLARS)	UNITED STATES	CANADA	UNITED KINGDOM	ECUADOR	OTHER	SUBTOTAL	SYNTHETIC OIL - CANADA	TOTAL
YEAR ENDED DECEMBER 31, 1998								
Revenues								
Crude oil and natural gas liquids								
Transfers to consolidated operations	$ 32.4	7.1	12.3	--	--	51.8	35.4	87.2
Sales to unaffiliated enterprises	3.2	48.3	58.0	19.1	--	128.6	17.6	146.2
Natural gas	132.1	24.0	10.0	--	--	166.1	--	166.1
Total oil and gas revenues	167.7	79.4	80.3	19.1	--	346.5	53.0	399.5
Other operating revenues/1/	11.4	2.7	14.8	2.2	2.7	33.8	(.1)	33.7
Total revenues	179.1	82.1	95.1	21.3	2.7	380.3	52.9	433.2
Costs and expenses								
Production costs	43.6	34.3	35.7	7.0	--	120.6	34.5	155.1
Exploration costs charged to expense	16.6	13.8	3.5	--	21.2	55.1	--	55.1
Undeveloped lease amortization	6.7	3.8	--	--	--	10.5	--	10.5
Depreciation, depletion and amortization	66.0	37.8	42.9	10.2	--	156.9	6.2	163.1
Impairment of long-lived assets	29.9	10.1	24.3	--	15.1	79.4	--	79.4
Cancellation of a drilling rig contract	--	7.2	--	--	--	7.2	--	7.2
Selling and general expenses	15.7	6.0	3.6	.1	1.4	26.8	.1	26.9
Total costs and expenses	178.5	113.0	110.0	17.3	37.7	456.5	40.8	497.3
	.6	(30.9)	(14.9)	4.0	(35.0)	(76.2)	12.1	(64.1)
Income tax expense (benefit)	(.1)	(15.2)	(1.6)	(.8)	.1	(17.6)	3.9	(13.7)
Results of operations/2/	$ .7	(15.7)	(13.3)	4.8	(35.1)	(58.6)	8.2	(50.4)
YEAR ENDED DECEMBER 31, 1997								
Revenues								
Crude oil and natural gas liquids								
Transfers to consolidated operations	$ 64.1	13.7	--	--	--	77.8	46.8	124.6
Sales to unaffiliated enterprises	10.8	57.9	95.3	34.7	--	198.7	21.1	219.8
Natural gas	196.7	22.1	12.2	--	--	231.0	--	231.0
Total oil and gas revenues	271.6	93.7	107.5	34.7	--	507.5	67.9	575.4
Other operating revenues/3/	3.2	24.0	14.1	1.3	2.5	45.1	--	45.1
Total revenues	274.8	117.7	121.6	36.0	2.5	552.6	67.9	620.5
Costs and expenses								
Production costs	43.5	39.2	32.5	11.0	--	126.2	38.6	164.8
Exploration costs charged to expense	44.5	11.7	10.9	--	17.2	84.3	--	84.3
Undeveloped lease amortization	6.7	3.6	.1	--	.1	10.5	--	10.5
Depreciation, depletion and amortization	79.4	31.4	43.7	11.4	--	165.9	6.5	172.4
Impairment of long-lived assets	7.7	20.4	--	--	--	28.1	--	28.1
Selling and general expenses	14.3	5.2	2.7	.2	1.4	23.8	.1	23.9
Total costs and expenses	196.1	111.5	89.9	22.6	18.7	438.8	45.2	484.0
	78.7	6.2	31.7	13.4	(16.2)	113.8	22.7	136.5
Income tax expense (benefit)	27.2	1.4	15.4	(1.1)	.1	43.0	8.4	51.4
Results of operations/2/	$ 51.5	4.8	16.3	14.5	(16.3)	70.8	14.3	85.1

/1/ Includes pretax gains of $4 from modification of a U.K. long-term sales contract and $2.4 from recovery on a 1996 contract modification in Ecuador.
/2/ Excludes corporate overhead and interest.
/3/ Includes pretax gains of $20.7 from sale of Canadian properties and $1.6 from recovery on a 1996 contract modification in Ecuador.

SCHEDULE 4 - RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES (CONTINUED)

(MILLIONS OF DOLLARS)	UNITED STATES	CANADA	UNITED KINGDOM	ECUADOR	OTHER	SUBTOTAL	SYNTHETIC OIL - CANADA	TOTAL
YEAR ENDED DECEMBER 31, 1996								
Revenues								
Crude oil and natural gas liquids								
Transfers to consolidated operations	$ 71.8	57.6	34.4	--	--	163.8	44.6	208.4
Sales to unaffiliated enterprises	14.3	24.0	67.7	35.0	--	141.0	18.7	159.7
Natural gas	147.1	17.3	14.4	--	7.8	186.6	--	186.6
Total oil and gas revenues	233.2	98.9	116.5	35.0	7.8	491.4	63.3	554.7
Other operating revenues/1/	32.0	5.0	14.5	--	1.0	52.5	--	52.5
Total revenues	265.2	103.9	131.0	35.0	8.8	543.9	63.3	607.2
Costs and expenses								
Production costs	45.4	30.8	34.7	10.9	.7	122.5	38.0	160.5
Exploration costs charged to expense	34.9	7.8	13.4	--	4.4	60.5	--	60.5
Undeveloped lease amortization	6.5	3.0	.1	--	.1	9.7	--	9.7
Depreciation, depletion and amortization	60.5	25.2	40.8	8.9	6.6	142.0	5.6	147.6
Selling and general expenses	12.7	5.2	3.0	.2	1.3	22.4	.1	22.5
Loss from modifications to foreign crude oil contracts	--	--	--	8.8	(8.2)	.6	--	.6
Total costs and expenses	160.0	72.0	92.0	28.8	4.9	357.7	43.7	401.4
	105.2	31.9	39.0	6.2	3.9	186.2	19.6	205.8
Income tax expense	37.1	11.3	24.3	1.2	.4	74.3	7.5	81.8
Results of operations/2/	$ 68.1	20.6	14.7	5.0	3.5	111.9	12.1	124.0

/1/ Includes pretax gain of $27.9 on sale of U.S. onshore properties.
/2/ Excludes corporate overhead and interest.

SCHEDULE 5 - CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES

(MILLIONS OF DOLLARS)	UNITED STATES	CANADA	UNITED KINGDOM	ECUADOR	OTHER	SUBTOTAL	SYNTHETIC OIL - CANADA	TOTAL
DECEMBER 31, 1998								
Unproved oil and gas properties	$ 102.4	31.8	1.3	--	20.3	155.8	--	155.8
Proved oil and gas properties	1,536.1	755.5/1/	836.0	199.5	--	3,327.1	140.8	3,467.9
Gross capitalized costs	1,638.5	787.3	837.3	199.5	20.3	3,482.9	140.8	3,623.7
Accumulated depreciation, depletion and amortization								
Unproved oil and gas properties	(50.7)	(18.2)	(1.0)	--	(19.1)	(89.0)	--	(89.0)
Proved oil and gas properties/2/	(1,250.4)	(317.8)/1/	(585.6)	(145.1)	--	(2,298.9)	(23.1)	(2,322.0)
Net capitalized costs	$ 337.4	451.3	250.7	54.4	1.2	1,095.0	117.7	1,212.7
DECEMBER 31, 1997								
Unproved oil and gas properties	$ 96.8	32.9	4.3	--	19.6	153.6	--	153.6
Proved oil and gas properties	1,468.9	732.9/1/	764.5	189.3	--	3,155.6	133.6	3,289.2
Gross capitalized costs	1,565.7	765.8	768.8	189.3	19.6	3,309.2	133.6	3,442.8
Accumulated depreciation, depletion and amortization								
Unproved oil and gas properties	(47.0)	(18.2)	(1.0)	--	(4.0)	(70.2)	--	(70.2)
Proved oil and gas properties/2/	(1,185.6)	(295.0)/1/	(520.0)	(134.9)	--	(2,135.5)	(18.8)	(2,154.3)
Net capitalized costs	$ 333.1	452.6	247.8	54.4	15.6	1,103.5	114.8	1,218.3

/1/ Includes net costs of $276.3 in 1998 and $249 in 1997 related to the Hibernia and Terra Nova oil fields.
/2/ Does not include reserve for dismantlement costs of $154.7 in 1998 and $153 in 1997.

SCHEDULE 6 - STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES/1/

(MILLIONS OF DOLLARS)	UNITED STATES	CANADA/2/	UNITED KINGDOM	ECUADOR	TOTAL
DECEMBER 31, 1998					
Future cash inflows	$ 1,120.5	647.6	667.2	167.2	2,602.5
Future development costs	(182.7)	(177.5)	(64.6)	(14.9)	(439.7)
Future production and abandonment costs	(361.1)	(269.9)	(372.6)	(93.9)	(1,097.5)
Future income taxes	(139.0)	(28.3)	(23.6)	(.6)	(191.5)
Future net cash flows	437.7	171.9	206.4	57.8	873.8
10% annual discount for estimated timing of cash flows	(138.1)	(74.3)	(56.4)	(23.1)	(291.9)
Standardized measure of discounted future net cash flows	$ 299.6	97.6	150.0	34.7	581.9
DECEMBER 31, 1997					
Future cash inflows	$ 1,487.7	769.6	972.0	366.3	3,595.6
Future development costs	(154.6)	(253.1)	(104.2)	(49.7)	(561.6)
Future production and abandonment costs	(348.5)	(296.3)	(356.3)	(111.4)	(1,112.5)
Future income taxes	(286.0)	(6.8)	(145.7)	(26.7)	(465.2)
Future net cash flows	698.6	213.4	365.8	178.5	1,456.3
10% annual discount for estimated timing of cash flows	(214.7)	(115.2)	(104.0)	(59.4)	(493.3)
Standardized measure of discounted future net cash flows	$ 483.9	98.2	261.8	119.1	963.0

/1/Excludes future net cash flows from synthetic oil of $64.1 at December 31, 1998, and $461.5 at December 31, 1997.
/2/Excludes future net cash flows attributable to 48.3 million barrels of crude oil to be added to reserves as development of the Hibernia and Terra Nova oil fields proceeds.

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

(MILLIONS OF DOLLARS)	1998	1997	1996
Net changes in prices, production costs and development costs	$ (894.8)	(1,437.3)	643.2
Sales and transfers of oil and gas produced, net of production costs	(132.3)	(230.8)	(324.9)
Net change due to extensions and discoveries	125.4	278.6	450.8
Net change due to purchases and sales of proved reserves	4.5	17.4	(121.4)
Development costs incurred	165.4	214.2	201.5
Accretion of discount	129.0	217.6	115.6
Revisions of previous quantity estimates	30.7	55.0	54.8
Net change in income taxes	191.0	327.3	(352.2)
Net increase (decrease)	(381.1)	(558.0)	667.4
Standardized measure at January 1	963.0	1,521.0	853.6
Standardized measure at December 31	$ 581.9	963.0	1,521.0

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, 1998/1/					
Sales and other operating revenues/2/	$ 439.8	447.8	432.2	374.7	1,694.5
Income (loss) before income taxes	24.8	36.9	15.4	(85.4)	(8.3)
Net income (loss)	15.5	22.2	9.0	(61.1)	(14.4)
Net income (loss) per Common share - basic	.35	.49	.20	(1.36)	(.32)
Net income (loss) per Common share - diluted	.35	.49	.20	(1.36)	(.32)
Cash dividends per Common share	.35	.35	.35	.35	1.40
Market Price/3/					
High	54 7/16	53 11/16	51 15/16	42 5/16	54 7/16
Low	47 7/16	48 1/8	34 1/2	36 3/16	34 1/2
YEAR ENDED DECEMBER 31, 1997/1/					
Sales and other operating revenues/2/	$ 507.4	506.7	555.5	563.8	2,133.4
Income before income taxes	53.4	42.8	64.3	51.2	211.7
Net income	30.6	27.6	42.3	31.9	132.4
Net income per Common share - basic	.68	.62	.94	.71	2.95
Net income per Common share - diluted	.68	.61	.94	.71	2.94
Cash dividends per Common share	.325	.325	.35	.35	1.35
Market Price/3/					
High	54 1/4	49 1/4	58 13/16	62 9/16	62 9/16
Low	46	43	48 3/4	53 5/16	43

/1/The effects of special gains (losses) on quarterly net income are reviewed in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 12 and 13 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
1998					
Quarterly totals	$ --	4.2	--	(62.1)	(57.9)
Per Common share - basic	--	.09	--	(1.38)	(1.29)
Per Common share - diluted	--	.09	--	(1.38)	(1.29)
1997					
Quarterly totals	--	--	(.1)	.2	.1
Per Common share - basic	--	--	--	--	--
Per Common share - diluted	--	--	--	--	--

/2/Amounts for 1997 and the first three quarters of 1998 have been restated to conform to presentation for the year ended December 31, 1998.
/3/Market prices of Common Stock are as quoted on the New York Stock Exchange.

EXHIBIT 13

1998 ANNUAL REPORT TO SECURITY HOLDERS

CONTENTS

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's interest percentage in exploration and production projects and other jointly owned facilities is shown following the name of each field, block or facility.

MURPHY OIL AT A GLANCE

Murphy Oil Corporation is a worldwide oil and gas exploration and production company with refining and marketing operations in the United States and the United Kingdom. Throughout its history, the Company has earned a reputation for conservative financial management, good strategic decisions, and the ability to steer a steady course in the wake of fluctuating commodity prices and industry uncertainty. Never were these strengths more necessary than in 1998, when Murphy - - -- along with the rest of the oil and gas industry -- endured a slump in oil prices that adversely affected its financial performance throughout the year.

Operationally, it was a different story. For the eighth consecutive year, proved reserves grew. The Company's production profile, already one of the strongest in the industry, strengthened as several new oil fields came on stream that provide long production lives at a low cost. Discoveries in deepwater Gulf of Mexico, where the Company's early entry has given it a major presence, and onshore Louisiana highlighted the year's domestic exploration efforts. Murphy's taste for exposure to significant growth offered by international frontier exploration was reinforced in 1998 by acquisition of acreage offshore Malaysia.

[GRAPH - INCOME CONTRIBUTION FROM CONTINUING OPERATIONS BY FUNCTION]

[GRAPH - ESTIMATED NET PROVED HYDROCARBON RESERVES]

Downstream operations continued to reduce operating costs while increasing operational efficiency and reliability. Notable in 1998 was the success of Murphy's marketing expansion in collaboration with Wal-Mart. Murphy has built 35 stations in Wal-Mart parking areas, giving the Company a leading position in a unique niche in the U.S. marketplace; further expansion is planned in 1999. Costs for the initiative are in line with projections, while volume is exceeding expectations. Murphy's U.K. refining and marketing efforts recorded another profitable year in 1998.

The Company's commitment to and investment in employee safety, environmental stewardship and corporate responsibility resulted in yet another year of achievement well above industry norms.

All in all, 1998 will be remembered as much for accomplishments -- growth in proved reserves, increasing oil production, significant discoveries and the success of the Wal-Mart marketing initiative -- as for the challenges of low commodity prices. As the Company looks forward to 1999 and beyond, the key elements are in place -- quality oil properties; growing production; a focused, robust exploration portfolio; and a strong balance sheet -- to enable the Company to rebound from 1998 stronger, bigger and more profitable than before.

[GRAPH - CASH FLOW FROM CONTINUING OPERATIONS BY FUNCTION]

[GRAPH - CAPITAL EXPENDITURES BY FUNCTION]

HIGHLIGHTS

FINANCIAL

(Thousands of dollars except per share data)	1998	1997	1996
FOR THE YEAR*			
Revenues	$ 1,698,848	2,137,767	2,022,176
Income (loss) from continuing operations	(14,394)	132,406	125,956
Net income (loss)	(14,394)	132,406	137,855
Cash dividends paid	62,939	60,573	58,294
Capital expenditures for continuing operations	388,799	468,031	418,056
Net cash provided by continuing operations	321,091	401,843	472,480
Average Common shares outstanding - diluted	44,955,679	44,960,907	44,904,636
AT END OF YEAR			
Working capital	$ 56,616	48,333	56,128
Total assets	2,164,419	2,238,319	2,243,786
Notes payable	189,705	28,367	20,871
Nonrecourse debt of a subsidiary	143,768	177,486	180,957
Stockholders' equity	978,233	1,079,351	1,027,478
PER SHARE OF COMMON STOCK*			
Income (loss) from continuing operations - diluted	$ (.32)	2.94	2.80
Net income (loss) - diluted	(.32)	2.94	3.07
Cash dividends paid	1.40	1.35	1.30
Stockholders' equity	21.76	24.04	22.90

*Includes special items that are detailed in Management's Discussion and Analysis, page 9 of the attached Form 10-K report.

OPERATING

	1998	1997	1996
NET CRUDE OIL AND GAS LIQUIDS PRODUCED - BARRELS A DAY	59,128	57,494	53,210
United States	7,798	10,760	11,645
International	51,330	46,734	41,565
NET NATURAL GAS SOLD - THOUSANDS OF CUBIC FEET A DAY	230,901	268,669	220,633
United States	169,519	211,207	155,017
International	61,382	57,462	65,616
CRUDE OIL REFINED - BARRELS A DAY	165,580	161,560	157,886
United States	134,800	134,854	126,586
United Kingdom	30,780	26,706	31,300
PETROLEUM PRODUCTS SOLD - BARRELS A DAY	174,152	163,430	161,459
United States	137,620	134,209	127,590
United Kingdom	36,093	28,977	33,615
Canada	439	244	254

LETTER TO THE SHAREHOLDERS

[PHOTOGRAPH APPEARS HERE]

DEAR FELLOW SHAREHOLDER:

Like most other oil and gas companies, Murphy Oil Corporation's bottom line was adversely affected in 1998 by low commodity prices, which began to fall in the fourth quarter of 1997 and continued to slide throughout 1998. As a result, I must report to you that your Company's earnings before special items in 1998 were down 67% to $43.5 million ($.97 a share), and after special items, primarily a $57.6 million after-tax write-down of the carrying value of oil and gas assets, we experienced a net loss of $14.4 million ($.32 a share). A word about the write-down. It is absolutely necessary that the value of our assets reflect the world as it actually exists. The unavoidable fact is that crude oil prices were lower on December 31, 1998, in nominal terms, than at any year-end since 1973 and in real terms than at any year-end since 1931. Clearly, this influenced our price outlook and caused us to reevaluate forward assumptions, triggering the write-down. Significantly, none of Murphy's core properties -- Hibernia, Terra Nova, Syncrude, Schiehallion and Mungo/Monan -- were impaired.

There is no escaping the fact that economic troubles, almost exclusively outside the United States and particularly in Asian markets, caused a marked slowdown in energy growth leading to a significant drop in crude oil prices. Asia alone went from adding 750,000 barrels a day of demand in 1997 to dropping a like amount in 1998. This swing of 1.5 million barrels a day, coupled with Iraq's renewed crude oil sales, sent markets tumbling into one of their periodic tailspins. All companies in this remarkably competitive business are going to be telling their shareholders about reductions in capital spending, cost-cutting measures and a reduced bottom line. In that regard, Murphy is no different. But I can also tell you that your Company's proven, disciplined approach to financial management, which has sustained us through bad times and guided us during boom years, helped cushion the blows in 1998 and gives us important advantages as we look ahead to 1999 and beyond.

In fact, I believe our Company established a platform in 1998 from which we will profitably grow for many years. Let's review the past year.

*During 1998, two low-cost U.K. oil fields, Mungo/Monan and Schiehallion, started up. In Canada, the Hibernia oil field was on stream for its first full year and will hit plateau production rates this year. Cash lifting costs at plateau are now projected at around $2.00 a barrel. Syncrude set a new production record of 210,000 barrels a day and reduced cash lifting cost to a record low of $8.99 a barrel. Overall, as new lower-cost fields are added to our mix, costs are driven down even more. Cash lifting costs across all of Murphy's barrels are estimated to be $4.10 a barrel in 1999, $3.54 a barrel if

[GRAPH - HYDROCARBON PRODUCTION REPLACEMENT]

Syncrude (a mining operation) is excluded, compared to $4.35 in 1998 ($3.79 excluding Syncrude), and are the lowest in six years. Production should average 107,000 equivalent barrels a day in 1999, a Company record.

*Exploration results in 1998 were excellent. Onshore South Louisiana, we extended the N.E. Wright field with the Guidry No. 1 well, penetrating 150 feet of pay in four sands. A likely 50 billion cubic feet (BCF) of natural gas reserves were proved up and another potentially equal sized offset spuds in the second quarter. Gulf of Mexico shelf results reflect hitting on 14 of 16 wells. While no single shelf discovery made an impact, collectively these reserve additions will maintain our 1999 U.S. natural gas production at 1998 levels. Deepwater exploration in the Gulf of Mexico kicked off in 1998. Four wells were drilled and two, the last two, were discoveries. Boomslang, in Ewing Bank Block 994, encountered 185 feet of pay, and importantly, sets up a much larger prospect called Sidewinder in the cornering block. The North Marlin wildcat on Viosca Knoll Block 827 found reserves of around 100 BCF and has an offset with the same potential that spuds in the third quarter of 1999. Most importantly, the Habanero wildcat in Garden Banks Block 341 penetrated over 200 feet of excellent reservoir rock to provide Murphy's third consecutive, and first marquee, deepwater discovery. A separate and potentially larger prospect named Moccasin, at Garden Banks Block 253, will be drilled later this year. Success at Habanero lowers the risk at Moccasin.

*Murphy Oil Corporation added 53 million equivalent barrels of reserves in 1998 and ended the year with 380 million equivalent barrels of proved reserves, the highest in the Company's history, and the eighth consecutive year for an increase.

*Murphy's downstream business expanded its arrangement with Wal-Mart as 1998 ended. I fully expect that over 100 sites will be in operation before the end of 1999, up from 35 today. The capital cost per unit is extraordinarily low because no real estate is purchased nor is a convenience store built. In addition, volumes are much higher than traditional SPUR stations, resulting in quite low operating costs, and most importantly, a competitive advantage.

I am proud of what was accomplished in 1998 although the near depression level conditions existing in our industry at year-end masked our successes. In 1999, we will control those areas within our grasp -- production volume and cost, as well as capital spending. In addition, we will continue to search for opportunities. Cash-strapped companies are facing difficult choices and asset sales will likely result. On the plus side, world oil demand climbed in 1998 despite the Asian meltdown and is forecast to increase by 1.1 million barrels a day in 1999. This increase, when coupled with high-cost production shut-ins and the significant reduction in new investment, means recovery is under way. Our Company will work out of this, and Murphy Oil Corporation will be a leaner, more efficient and much, much stronger company on the other side.

I appreciate your patience and predict it will be rewarded.

/s/ Claiborne P. Deming

Claiborne P. Deming
President and Chief Executive Officer

March 1, 1999
El Dorado, Arkansas

EXPLORATION AND PRODUCTION

THE YEAR IN REVIEW

A successful exploration program, a full year of production from the Hibernia oil field (6.5%) offshore eastern Canada, and commencement of production from two new fields in the United Kingdom highlighted 1998 exploration and production activity. Economic woes that began in Asia, spread to Latin America and suppressed the demand for crude oil worldwide contributed to a significant decline in crude oil prices during the year. However, Murphy's exploration and production team managed to stay focused by growing the Company with the drill bit and improving an already impressive production profile, and by making significant additions to its international frontier exploration acreage.

Earnings from the Company's exploration and production activities, before special items, totaled $5.8 million in 1998. Proved reserves at the end of 1998 increased to 380 million barrels of oil equivalent, marking the eighth consecutive year that Murphy has more than replaced its hydrocarbon production. Although worldwide production of 97,612 barrels of oil equivalent a day represented a reduction of approximately 5% from 1997's record levels, crude oil production increased 3%. Expectations for an overall 10% increase in 1999 should once again propel the Company into record territory.

Murphy's core operating areas include four of the world's premier, politically secure oil and natural gas basins: the Gulf of Mexico, the Jeanne d'Arc basin off the east coast of Canada, western Canada and the United Kingdom.

Over 65% of Murphy's exploration capital was invested in the Gulf of Mexico and onshore South Louisiana in 1998, and a similar allocation is anticipated for 1999. In addition to its established production base on the Gulf of Mexico continental shelf, Murphy has amassed a significant leasehold acreage position in the burgeoning, and ever more important, deepwater play. The year 1998 proved to be a breakthrough year, as the Company made its first deepwater discoveries.

[GRAPH - NET HYDROCARBONS PRODUCED]

Offshore eastern Canada in the Jeanne d'Arc basin, the Hibernia field produced at an average gross rate of 65,000 barrels a day. Planned plateau production of 135,000 barrels a day is expected to be achieved in 1999. Elsewhere in the basin, the Terra Nova oil development project (12%) remains on schedule to deliver first oil, within budget, before the end of the year 2000. Construction and fabrication of the floating production system commenced in 1998. Terra Nova is currently expected to achieve gross peak production of 115,000 barrels of crude oil a day. Murphy's Canadian activities also include an interest in Syncrude (5%), the world's largest producer of synthetic crude oil from oil sands. This light, sweet crude oil could eventually provide half of Canada's crude oil production.

EXPLORATION AND PRODUCTION

(Thousands of dollars)	1998	1997
Income contribution*	$ 5,809	84,984
Total assets	1,385,879	1,402,684
Capital expenditures	331,647	423,181
Crude oil and liquids produced - barrels a day	59,128	57,494
Natural gas sold - MCF a day	230,901	268,669
Net proved hydrocarbon reserves - thousands of oil equivalent barrels	379,900	362,100

*Before special items

Since the discovery of the giant Ninian field in the early 1970s, the United Kingdom has been an integral part of Murphy's portfolio. Production from the Schiehallion (5.9%) and Mungo/Monan (12.7%) fields came on stream during the third quarter of 1998 and provides the catalyst for what is expected to be a 45% increase in the Company's oil production from the area.

[PHOTOGRAPH APPEARS HERE]

Although Murphy's exploration programs emphasize those areas where significant production has been established, the Company also possesses the technical expertise to identify frontier prospects, along with the resources to acquire significant ownership positions therein. Utilizing that ownership position to fund exploratory drilling has been an available option that will continue to be implemented when warranted. Frontier areas of particular note include the U.K. Atlantic Margin, Philippines, Pakistan, Alaska, and most recently, Malaysia, where production sharing contracts covering three offshore blocks were recently signed.

Murphy has been well served by its strategy to use long-lived, low-cost oil properties in secure, established basins around the world to fund an active, yet focused, exploration program that seeks meaningful growth opportunities. Coupled with the Company's conservative financial practices, this strategy has put Murphy in a position, both operationally and financially, to use the exploration and production side of its business as its primary growth vehicle.

A review of the Company's principal exploration and production activities is presented in the sections that follow. Unless otherwise indicated, average daily production rates are net to the Company after deduction for royalty interests. The terms crude oil production and oil production include natural gas liquids where applicable.

Murphy's U.S. operations are concentrated in the Gulf of Mexico region and onshore South Louisiana. The Company participated in 20 exploratory wells during 1998, 17 of which were successful, for an 85% success ratio. Additions to the Company's U.S. proved reserves totaled 107 billion cubic feet of natural gas

[GULF OF MEXICO MAP]

equivalents in 1998, which amounted to 136% of U.S. hydrocarbon production. Murphy upgraded its leasehold position in the Gulf by participating in two 1998 federal lease sales, acquiring interests ranging from 33% to 100% in 21 blocks, 15 of which are in deep water, where the Company now has an interest in 97 leases.

The DEEPWATER GULF OF MEXICO continues to offer the potential for impact reserves in areas where infrastructure is growing. Murphy intends to dedicate a larger percentage of exploratory drilling capital to this play. Discoveries at Ewing Bank Block 994 (Boomslang, 45%) and at Viosca Knoll Block 827 (North Marlin, 30%) highlighted 1998 activity. The Boomslang well, located in approximately 850 feet of water, penetrated 185 feet of net oil pay and enhanced the prospects located on five adjacent blocks in which Murphy has a working interest of 42.5%. The North Marlin well encountered a hydrocarbon-bearing interval similar to the predominantly natural gas reservoirs in the Company's nearby Tahoe field (30%). Water depth at North Marlin exceeds 2,500 feet. Both of these areas contain significant additional reserve potential that will be explored over the next 18 months. Two additional deepwater wildcats spudded in the fourth quarter of 1998, one in the "Auger" basin at Garden Banks Block 341 (Habanero, 33.8%) and one in the "Enchilada" basin at Garden Banks Block 168 (Wadden Zee, 33.3%). In early 1999, it was announced that the Habanero well, located in approximately 2,000 feet of water, had encountered over 200 feet of net oil pay in two zones. Evaluation work to determine the extent of this discovery continues.

Although the drop in oil and natural gas prices will curtail exploration activity, Murphy remains active on the GULF OF MEXICO OUTER CONTINENTAL SHELF. Positive drilling outcomes resulted in 14 successful wells, all of which will be on stream by the end of 1999. Initial gross production from the larger discoveries at Vermilion Block 130 (75%), Ship Shoal Block 59 (50%), South Pelto Block 18 (25%), Matagorda Island Block 565 (40%), Vermilion Block 335 (35%) and East Cameron Block 38 (33.3%) will total approximately 57 million cubic feet of natural gas a day.

[PHOTOGRAPH APPEARS HERE]

The Destin Dome Block 56 unit (33.3%) is one of the largest undeveloped natural gas discoveries remaining in the United States. Located in federal waters 30 miles off the coast of Florida, three previously drilled exploratory wells have confirmed a significant reservoir of dry natural gas in the Norphlet sandstone. Murphy and its two partners filed a development plan with the U.S. Minerals Management Service in November 1996. A rigorous regulatory process designed to protect the environment and ensure compatibility with other uses of surrounding areas is under way. Completion of the regulatory review process could extend into late 1999.

ONSHORE SOUTH LOUISIANA, a significant natural gas discovery at the N.E. Wright field (50%) is currently producing, through temporary facilities, at a gross rate of approximately 10 million cubic feet a day. The well logged 150 feet of net natural gas pay in four sands and confirmed a large structure underlying the field. Delineation drilling is slated for 1999 to determine the magnitude of the discovery and the development plan.

CANADA continues to be Murphy's largest source of crude oil reserves and production and set a production record of 28,199 barrels a day in 1998. An increasing proportion of this supply (57% in the fourth quarter of 1998) is provided by premium properties, namely the Hibernia field and Syncrude. With the Terra Nova field to follow, Murphy can look forward to long-lived, stable volumes of profitable production, augmenting its large resource base in the more traditional areas of western Canada, where the Company set a record of 49 million cubic feet a day of natural gas production in 1998.

[GRAPH - CAPITAL EXPENDITURES--EXPLORATION AND PRODUCTION]

[PHOTOGRAPH APPEARS HERE]

Murphy enjoyed its first full year of production in the Jeanne d'Arc basin off the EAST COAST OF CANADA following start-up of the Hibernia field in late 1997. Early performance exceeded expectations, resulting in production curtailment while awaiting placement of water and gas injection wells. Later in 1998, mechanical problems with the first gas injection well necessitated additional curtailment for conservation of produced gas. A second gas injector was completed in early 1999. Despite these temporary reservoir management issues, the field produced 23.9 million barrels during the year, or 4,192 barrels a day net to Murphy, exceeding budget expectations. More importantly, performance data collected during the year increased confidence in the capability of the reservoir and platform. As a result, 1999 performance is expected to continue to exceed Murphy's original projections, in terms of both higher production and lower operating cost per unit.

The Hibernia reservoir is the source of current production from the field and accounts for 485 million barrels of the 615 million barrels of reserves projected to be recovered from the field. The remaining oil is contained within the Avalon reservoir, which also offers new exploratory opportunities that have been identified and are being considered. Such efforts have the potential to add significant new reserves and to maintain plateau production levels well into the next decade.

Development of the Terra Nova oil field was approved in early 1998. Key components, including the production vessel, turret and topsides, are under construction and include debottlenecking of the facility from a design capacity of 125,000 to 150,000 barrels a day. This will accelerate production of the 300 to 400 million barrels estimated to be recoverable from the field. First oil is anticipated near the end of the year 2000.

Murphy earned a 20% interest in additional acreage off Canada's east coast in 1998 by joining in the drilling of an exploratory well on the Scotian Shelf in a region close to the Sable Island producing area. Although the initial well was unsuccessful, further evaluation of this acreage position, along with an existing parcel in the Jeanne d'Arc basin at Cape Race (25%), should yield additional exploration prospects in future years.

[GRAPH - WORLDWIDE EXTRACTION COSTS]

[WESTERN CANADA MAP]

Murphy has been active in WESTERN CANADA for many years. By late 1998, supply and demand for Canadian natural gas became much more balanced as a result of pipeline expansions, and prices rose accordingly. In anticipation of this, Murphy's exploration effort in western Canada has been directed toward natural gas in northern Alberta and British Columbia. Successful delineation of the 1997 discovery at Josephine (50-63%) and drilling successes at Cranberry (100%) and Birley (50%) contributed to the Company's record Canadian gas production in 1998. Exploration and development activities will continue in 1999, and further increases in natural gas deliverability are anticipated.

In early 1998, Murphy responded quickly to low prices for heavy crude oil by significantly curtailing heavy oil production. Higher cost wells were shut in and thermal pilot programs were suspended. Similar reactions throughout the industry reduced availability of heavy crude oil and led to modest price improvements, allowing some production to be reactivated later in 1998. The Company's light oil portfolio in western Canada is mature and continues to be managed with a "harvesting" mentality.

SYNCRUDE, Canada's largest source of crude oil production, combines mining, extraction and upgrading technologies to produce a light, sweet synthetic crude product. During 1998, the project laid the foundation for future expansion by approving construction of the Aurora mine. This mine, located on one of the most attractive leases in the Athabasca deposit, will exploit newly developed technologies and provide a less costly source of oil sand for decades to come. Additional expansion stages have been identified that, when completed, will increase production to 400,000 gross barrels a day by 2007. The actual pace of development has yet to be determined.

Murphy's exploration and production operations in the UNITED KINGDOM are centered in the North Sea and Atlantic Margin basins. Production averaged

[PHOTOGRAPH APPEARS HERE]

17,475 barrels of oil equivalent a day in 1998, an increase of more than 9% from a year ago. In addition to evaluating existing acreage, the Company's strategy is to build a portfolio of moderate-risk, moderate-reward prospects, with an emphasis on increasing ownership interest levels and securing operatorship where feasible.

The increase in U.K. production in 1998, along with an anticipated additional 35% increase in 1999, is attributable to new low-cost fields that came on stream during 1998. Gross production from Mungo/Monan reached peak levels of 65,000 barrels of oil a day by the end of the year. Mungo is produced from a normally unmanned platform, while Monan uses a subsea system. Both fields produce to a central processing facility. Development drilling will continue over the next two years.

Similarly, production from the Schiehallion field, west of the Shetland Islands, commenced during 1998. Gross production by the end of 1998 totaled approximately 86,000 barrels of oil a day. Development drilling will continue throughout 1999, building to peak gross production of 147,000 barrels of oil a day during the year.

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[UNITED KINGDOM MAP]

In 1998, Murphy acquired five additional blocks, with interests ranging from 20% to 37.5%, through U.K. licensing rounds. The Company's 1999 exploration program will concentrate on acquisition and evaluation of seismic data along with evaluation of acreage being offered in 1999 for licenses offshore the Faroe Islands and in the United Kingdom.

An important milestone in Murphy's frontier program culminated with the signing of production sharing contracts covering three blocks, which Murphy will operate, offshore MALAYSIA. Blocks SK 309 (85%) and SK 311 (85%) are contiguous blocks covering 2.4 million acres in shallow waters offshore Sarawak. Previous exploration has identified a number of attractive features and both blocks contain oil and gas discoveries. Work commitments over the next five years include acquisition of seismic data and drilling of four exploratory wells, for a minimum total expenditure of $15 million. Block K (80%) covers 4.1 million undrilled acres in deep waters offshore Sabah. It adjoins two blocks held by major oil companies, one of which contains a recently announced discovery. Commitments include a seismic program plus one exploratory well over seven years, with a minimum expenditure of $14 million.

[MALAYSIA MAP]

In 1998, Murphy was awarded a Geophysical Survey and Exploration Contract (GSEC) (80%) covering approximately 3.7 million acres in the northern Sulu Sea offshore PHILIPPINES. Under the GSEC, acquisition of seismic data is under way, with an option to drill an exploratory well.

After 20 years of force majeure, Murphy gained access to part of the 3.8 million acres included in the Kharan concession (100%) in PAKISTAN during 1998. The agreement gives the Company the right to explore the southern half of Kharan and to retain rights to explore in the northern half of the concession when access can be obtained. Activity during 1999 will include acquisition of seismic data and regional studies.

Murphy's holdings in ALASKA continue to position the Company in an area of renewed interest to the industry. New 3-D seismic surveys were acquired over the Challenge Island leases (25%), and a well spudded on the Red Dog prospect (12.5%) in early 1999. Development of the Northstar field (2%) was approved during 1998, but has been delayed due to presently deteriorating industry conditions. A successful farmout to an industry partner, in exchange for new 3-D seismic data and a carried interest in an optional well, reduced Murphy's interest in the Sandpiper project (28.8%).

Murphy's production from Block 16 (20%) in ECUADOR totaled 7,720 barrels of oil a day in 1998, essentially flat with 1997. Additional 3-D seismic data was acquired during the year and six development wells were drilled. Plans to expand pipeline capacity could allow for significant production increases.

Other frontier activity in 1998 included two unsuccessful wells in an unexplored basin north of the FALKLAND ISLANDS. Both wells indicated the presence of hydrocarbons but no commercial accumulation was found.

[PHOTOGRAPH APPEARS HERE]

REFINING, MARKETING & TRANSPORTATION

THE YEAR IN REVIEW

Murphy Oil Corporation's refining, marketing and transportation strategy has been clear and effective over the past several years: lowering operating costs while increasing operational efficiency and reliability; improving the return on assets through strategic capital investments; targeting and developing prudent, cost-effective means to supply the end user; entering into joint ventures where appropriate; and continuing the Company's commitment to environmental protection and performance.

The difficult environment experienced by Murphy and the entire oil industry in 1998 gave added significance to downstream operations, as the ability to convert crude oil into finished products and provide a steady, secure market became more important and made downstream assets relatively more valuable. In 1998, Murphy's downstream segment enjoyed a number of successes. One of the most promising was the ongoing endeavor with Wal-Mart. That program -- building high volume retail gasoline stations in the parking areas of Wal-Mart Supercenters under the Murphy USA(R) brand -- is successful and growing. As a result, Murphy now enjoys a leading position in the rapidly expanding market niche of gasoline sales at nontraditional outlets. In early 1999, 35 stations were in operation and plans call for a significant expansion during the year.

Earnings from Murphy's downstream activities, before special items, totaled $49.2 million in 1998. Although refining margins retreated significantly during the fourth quarter of 1998 and into 1999, respectable levels were achieved for most of the year. Combined with record throughputs, the Company was able to post downstream profits second only to the record year of 1997.

[PHOTOGRAPH APPEARS HERE]

[MAP OF WAL-MART SITES]

Murphy has built an integrated presence in each of its refinery markets by providing products to 59 terminals serving approximately 550 retail and wholesale stations and numerous unbranded customers in the United States, and 10 terminals supplying almost 400 retail and wholesale stations in the United Kingdom. The Company has refineries located in Meraux, Louisiana; Superior, Wisconsin; and Milford Haven, Wales.

REFINING, MARKETING & TRANSPORTATION

(Thousands of dollars)	1998	1997
Income contribution*	$ 49,230	56,738
Total assets	676,517	750,626
Capital expenditures	55,025	37,483
Crude oil processed - barrels a day	165,580	161,560
Products sold - barrels a day	174,152	163,430
Average gross margin on products sold - dollars a barrel		
United States	$ 1.47	1.79
United Kingdom	2.81	2.90

*Before special items.

The MERAUX REFINERY is capable of processing 100,000 barrels of crude oil a day and distributes petroleum products via pipeline and barge to an area covering 11 states. This distribution system consists of 35 terminals, 22 of which are wholly or jointly owned, and at the end of the year, supplied gasoline to 326 owned and wholesale branded stations.

In 1998, the Meraux refinery set its fourth consecutive record for annual throughput, averaging 101,834 barrels of crude oil a day. The refinery posted a composite 98% onstream time during 1998. Meraux successfully completed its transition to

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[U.S. DISTRIBUTION SYSTEM MAP]

processing a medium, sour crude oil imported from Latin America in place of a more expensive light, sweet crude. Murphy realized savings in freight costs through the use of large capacity tankers able to unload at the Louisiana Offshore Oil Port (3.2%), which is connected to the refinery by pipeline.

Murphy invested approximately $18 million in capital projects at Meraux in 1998 to improve efficiencies and meet U.S. Environmental Protection Agency (EPA) mandates, including completion of an upgrade to the Middle Distillate Hydrotreater that improved the refinery's ability to produce environmentally friendly products. Meraux's ongoing "green" fuels initiative is designed to produce lower sulfur gasoline and diesel fuel that will meet anticipated mandates from the EPA. This project is currently in the engineering phase, during which alternatives are being evaluated and preliminary equipment specifications and costs are being developed.

Murphy's SUPERIOR REFINERY can process 35,000 barrels of crude oil a day and distributes gasoline and distillates through 21 terminals. It supplied gasoline to 226 owned and SPUR(R) branded stations in the Upper Midwest at the end of 1998.

Taking advantage of the weak market for heavy sour crude, Superior processed over 9,000 barrels a day of heavy Canadian asphaltic crude, an increase of 25% over the average for recent years. As a result, 1998 was a record year for asphalt sales, as 1.8 million barrels were sold through three Company terminals in the Upper Midwest.

[GRAPH - CAPITAL EXPENDITURES--REFINING, MARKETING AND TRANSPORTATION]

In keeping with the Company's strategy to continuously improve operating efficiencies and to comply with federal government mandates, Murphy invested over $9 million in capital projects, including a $2.3 million asphalt polymer modification project at Superior. This modification enables the refinery to produce improved asphalt grades required by the federal government to extend road life and minimize repair costs. Furthering Murphy's strategy to supply the end user, the Company opened a marine fueling terminal in Duluth, Minnesota to directly service the active Lake Superior shipping traffic.

Murphy's U.K. operation includes an effective 30% interest in a refinery at MILFORD HAVEN, Wales that can process 108,000 barrels a day. Murphy transports products by rail to three distribution terminals, which in turn supply products to approximately 400 MURCO branded retail stations.

At the U.K. refinery, the 1996 installation of a high-pressure hydrotreating unit has enabled the Company to expand sales of cleaner-burning diesel fuel with a sulfur content of less than 50 parts per million. The refinery was one of only three in the United Kingdom with the capability to produce this highly profitable product in 1998.

Murphy produces, transports and resells crude oil in western CANADA. The Company owns interests in five crude oil pipeline systems, including the Manito (52.5%), Cactus Lake (13.1%), and North-Sask (36.1%) lines. In addition, Murphy operates a fleet of trucks that haul crude oil and natural gas liquids.

[GRAPH - REFINED PRODUCTS SOLD]

[U.K. DISTRIBUTION SYSTEM MAP]

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CORPORATE RESPONSIBILITY

Murphy Oil Corporation understands that its responsibilities extend beyond the bottom line. A healthy company depends on a healthy community, and a successful company creates a safe work environment. Murphy has developed and implemented operating procedures and invested in equipment upgrades that have earned excellent environmental and safety records for its operations. In addition, Murphy's investments in ongoing environmental improvements are part of a long-term commitment by the Company to address public concerns about the possible effects of carbon dioxide and other greenhouse gases on the environment.

ENVIRONMENTAL IMPROVEMENTS

In all of its downstream operations and surrounding communities, Murphy has achieved an outstanding record of environmental stewardship. Over the past decade, throughout the downstream segment of its business, the Company has invested more than $200 million in environmental improvement projects. In recent years, Murphy's refineries have reduced emissions of chemicals on the EPA's Toxic Release Inventory by 47%, maintained water emissions at less than 25% of permitted levels and reduced overall air emissions by more than 60%. In the United States, Murphy's marine terminal operations have achieved a 99.997% record of containment over the past 10 years.

Murphy's exploration and production operations on the Outer Continental Shelf of the Gulf of Mexico have a 99% or better compliance record for meeting the aqueous discharge levels defined in its permits. In Canada, the Company's ongoing improvements in its oil and gas operations include replacing flare pits with more environmentally friendly aboveground tanks and flarestacks.

EMPLOYEE SAFETY

Murphy has developed operational procedures and employee training programs that have kept the number of its lost-time accidents below industry averages. These programs have won refinery safety awards at both Meraux, Louisiana and Superior, Wisconsin. In 1998, the Company's terminal operations surpassed eight consecutive years without a lost-time injury. The Company also participates in federal and local emergency response drills coordinated by the Federal Emergency Management Agency and local emergency response teams. Each year, Murphy conducts nearly 30,000 hours of employee training including first aid, marine survival, firefighting and transportation of hazardous materials.

COMMUNITY PARTNERSHIPS

Everywhere Murphy operates, people benefit. The Company's 1,566 employees support the educational, cultural and charitable organizations in their local communities. The Company is also active in the civic life of the areas where it operates. From scholarship programs to support for the United Way, Murphy remains committed to being a good neighbor and a responsible corporate citizen.

[PHOTOGRAPH APPEARS HERE]

	1998	1997	1996	1995	1994
EXPLORATION AND PRODUCTION					
Net crude oil and condensate production - barrels a day					
United States	7,025	9,565	10,614	12,772	12,503
Canada - light	3,219	3,351	3,774	4,417	4,775
- heavy	9,676	11,538	9,670	8,864	6,840
- offshore	4,192	224	--	--	--
- synthetic	10,500	9,341	8,163	8,832	9,065
United Kingdom	14,975	13,438	12,918	14,588	13,389
Ecuador	7,720	7,802	6,005	5,274	1,967
Other	--	--	--	117	1,038
Net natural gas liquids production - barrels a day					
United States	773	1,195	1,031	964	852
Canada	612	617	689	740	748
United Kingdom	436	423	346	447	151
Total	59,128	57,494	53,210	57,015	51,328
Net natural gas sold - thousands of cubic feet a day					
United States	169,519	211,207	155,017	189,250	195,555
Canada	48,998	44,853	43,031	40,907	37,945
United Kingdom	12,384	12,609	15,247	10,671	10,138
Spain	--	--	7,338	10,898	12,620
Total	230,901	268,669	220,633	251,726	256,258
Total hydrocarbons produced - equivalent barrels/1/ a day	97,612	102,272	89,982	98,969	94,038
Estimated net hydrocarbon reserves - million equivalent barrels/1/,/2/	379.9	362.1	337.6	333.8	327.6
Weighted average sales prices/3/					
Crude oil and condensate - dollars a barrel					
United States	$ 12.76	19.43	20.31	16.61	15.36
Canada/4/ - light	12.03	17.74	19.97	16.45	14.61
- heavy	6.56	10.76	14.27	12.10	10.56
- offshore	10.49	15.15	--	--	--
- synthetic	13.73	19.92	21.20	17.28	15.92
United Kingdom	12.52	18.89	21.08	16.96	15.77
Ecuador	6.76	12.17	15.96	13.03	12.07
Other	--	--	--	15.12	14.80
Natural gas liquids - dollars a barrel					
United States	11.50	15.82	17.00	12.62	12.19
Canada/4/	9.16	14.87	13.69	9.70	9.21
United Kingdom	11.04	18.02	18.54	13.99	12.16
Natural gas - dollars a thousand cubic feet					
United States	2.18	2.57	2.60	1.64	1.91
Canada/4/	1.34	1.35	1.10	.97	1.42
United Kingdom/4/	2.23	2.65	2.58	2.53	2.43
Spain/4/	--	--	2.89	2.88	2.55
Net wells drilled					
Oil wells - United States	1.8	.8	3.7	3.0	2.6
- Canada	6.0	78.9	41.6	29.6	20.7
- Other	3.1	3.3	3.6	3.7	2.7
Gas wells - United States	7.8	9.7	14.7	3.6	4.0
- Canada	4.2	19.9	33.9	2.3	14.5
- Other	--	.1	--	.2	.4
Dry holes - United States	.8	6.8	3.9	1.9	4.1
- Canada	7.5	8.3	6.5	5.9	6.5
- Other	1.0	1.9	1.2	.6	.5
Total	32.2	129.7	109.1	50.8	56.0

/1/ Natural gas converted on an energy equivalent basis of 6:1.
/2/ At December 31.
/3/ Includes intracompany transfers at market prices.
/4/ U.S. dollar equivalent.

	1998	1997	1996	1995	1994
REFINING					
Crude capacity/1/ of refineries - barrels per stream day	167,400	167,400	167,400	167,400	167,400
Inputs/yields at refineries - barrels a day					
Crude - Meraux, Louisiana	101,834	101,150	93,929	91,940	78,252
- Superior, Wisconsin	32,966	33,704	32,657	33,217	30,592
- Milford Haven, Wales	30,780	26,706	31,300	30,346	32,038
Other feedstocks	11,404	8,178	6,315	8,280	8,731
Total inputs	176,984	169,738	164,201	163,783	149,613
Gasoline	73,482	72,672	69,658	73,964	67,746
Kerosine	15,394	14,959	14,965	15,113	16,989
Diesel and home heating oils	50,506	44,681	43,514	39,351	35,553
Residuals	21,310	20,852	19,756	19,641	15,444
Asphalt, LPG and other	12,565	13,139	12,513	10,158	10,077
Fuel and loss	3,727	3,435	3,795	5,556	3,804
Total yields	176,984	169,738	164,201	163,783	149,613
Average cost of crude inputs to refineries - dollars a barrel					
United States	$ 12.55	18.54	21.05	17.34	15.81
United Kingdom	13.62	20.12	21.66	17.59	16.32
MARKETING					
Products sold - barrels a day					
United States/2/ - Gasoline	60,990	62,244	58,726	61,690	56,310
- Kerosine	10,170	9,301	9,644	9,626	11,355
- Diesel and home heating oils	40,403	36,192	34,797	31,237	27,318
- Residuals	16,170	16,527	15,415	14,775	10,454
- Asphalt, LPG and other	9,887	9,945	9,008	8,815	7,754
	137,620	134,209	127,590	126,143	113,191
United Kingdom - Gasoline	14,058	11,467	13,919	14,277	16,601
- Kerosine	4,369	3,795	4,353	4,387	6,044
- Diesel and home heating oils	10,884	7,638	8,981	6,647	9,200
- Residuals	5,203	4,215	4,351	4,993	5,157
- LPG and other	1,579	1,862	2,011	930	3,264
	36,093	28,977	33,615	31,234	40,266
Canada	439	244	254	283	246
Total products sold/2/	174,152	163,430	161,459	157,660	153,703
Average gross margin on products sold - dollars a barrel					
United States/2/	$ 1.47	1.79	.27	.47	1.14
United Kingdom	2.81	2.90	2.08	2.26	2.17
Branded retail outlets/1/					
United States	552	585	527	514	588
United Kingdom	389	396	424	465	470
Canada	8	6	7	7	8
TRANSPORTATION					
Pipeline throughputs of crude oil - Canada - barrels a day	170,236	188,685	183,130	173,720	159,517
STOCKHOLDER AND EMPLOYEE DATA					
Common shares outstanding/1/ (thousands)	44,950	44,891	44,862	44,833	44,832
Number of stockholders of record/1/	3,684	3,899	4,093	4,873	4,778
Number of full-time and part-time employees/1/	1,566	1,446	1,406	1,889	1,827
Average number of full-time and part-time employees	1,498	1,421	1,777	1,874	1,852
Salaries, wages and benefits (thousands)	$ 97,307	92,495	95,583	96,035	93,216

/1/ At December 31.
/2/ Restated for 1997, 1996, 1995 and 1994.

DIRECTORS

R. Madison Murphy/1/
Chairman
Murphy Oil Corporation
El Dorado, Arkansas
Director since 1993

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

B. R. R. Butler/3/,/4/
Managing Director, Retired
The British Petroleum Company p.l.c.
Holbeton, Devon, England
Director since 1991

George S. Dembroski/2/,/3/
Vice Chairman, Retired
RBC Dominion Securities Limited
Toronto, Ontario, Canada
Director since 1995

H. Rodes Hart/1/,/3/,/4/
Chairman and Chief Executive Officer
Franklin Industries, Inc.
Nashville, Tennessee
Director since 1975

Vester T. Hughes Jr./2/,/4/
Partner
Hughes & Luce
Dallas, Texas
Director since 1973

C. H. Murphy Jr./1/,/3/
Former Chairman of the Board
Murphy Oil Corporation
El Dorado, Arkansas
Director since 1950

Michael W. Murphy/1/,/2/,/3/
President
Marmik Oil Company
El Dorado, Arkansas
Director since 1977

William C. Nolan Jr./1/,/2/,/3/
Partner
Nolan and Alderson
El Dorado, Arkansas
Director since 1977

Caroline G. Theus/3/,/4/
President
Inglewood Land and Development Company
Alexandria, Louisiana
Director since 1985

Lorne C. Webster/2/,/3/
Chairman and Chief Executive Officer
Prenor Group Ltd.
Montreal, Quebec, Canada
Director since 1989

OFFICERS

R. Madison Murphy
Chairman

Claiborne P. Deming
President and Chief Executive Officer

Steven A. Cosse'
Senior Vice President and General Counsel

Herbert A. Fox Jr.
Vice President

Bill H. Stobaugh
Vice President

Odie F. Vaughan
Treasurer

Ronald W. Herman
Controller

Walter K. Compton
Secretary

DIRECTORS EMERITI

William C. Nolan

George S. Ishiyama

Committees of the Board

/1/ Member of the Executive Committee chaired by Mr. R. Madison Murphy.

/2/ Member of the Audit Committee chaired by Mr. Hughes.

/3/ Member of the Executive Compensation and Nominating Committee chaired by Mr. William C. Nolan Jr.

/4/ Member of the Public Policy and Environmental Committee chaired by Mr. Butler.

PRINCIPAL SUBSIDIARIES

MURPHY EXPLORATION & PRODUCTION COMPANY
131 South Robertson Street
New Orleans, Louisiana 70112
(504) 561-2811

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

Engaged worldwide in crude oil and
natural gas exploration and production.

Enoch L. Dawkins
President

John C. Higgins
Senior Vice President, U.S. Exploration and Production

S. J. Carboni Jr.
Vice President, U.S. Production

James R. Murphy
Vice President, U.S. Exploration

David M. Wood
Vice President, Frontier Exploration and Production

Steven A. Cosse'
Vice President and General Counsel

Odie F. Vaughan
Vice President and Treasurer

Bobby R. Campbell
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, marketing and
transporting of petroleum products in
the United States.

Herbert A. Fox Jr.
President

Charles A. Ganus
Vice President, Marketing

Frederec C. Green
Vice President, Manufacturing and Crude Oil Supply

Steven A. Cosse'
Vice President and General Counsel

Odie F. Vaughan
Treasurer

Ronald W. Herman
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;
purchasing, transporting and reselling
of crude oil; and marketing of
petroleum products in Canada.

Harvey Doerr
President

W. Patrick Olson
Vice President, Production

R. D. Urquhart
Vice President, Supply and Transportation

Robert L. Lindsey
Vice President, Finance and Secretary

Odie F. Vaughan
Treasurer

MURPHY EASTERN OIL COMPANY
Winston House, Dollis Park,
Finchley
London N3 1HZ, England
181-371-3333

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, marketing and transporting of petroleum products in the United Kingdom.

W. Michael Hulse
President

James N. Copeland
Vice President, Legal and Personnel

Ijaz Iqbal
Vice President

Odie F. Vaughan
Treasurer

Walter K. Compton
Secretary

CORPORATE INFORMATION

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

MAILING ADDRESS
P. O. Box 7000
El Dorado, Arkansas 71731-7000

INTERNET ADDRESS
http://www.murphyoilcorp.com

E-MAIL ADDRESS
murphyoil@murphyoilcorp.com

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

TRANSFER AGENTS
Harris Trust Company of New York
77 Water Street
New York, New York 10005
Mailing address:
c/o Harris Trust and Savings Bank
P. O. Box 830
Chicago, Illinois 60690-9972

Montreal Trust Company of Canada
151 Front Street West
Toronto, Ontario M5J 2N1

REGISTRAR
Harris Trust Company of New York
77 Water Street
New York, New York 10005

ANNUAL MEETING
The annual meeting of the Company's shareholders will be held at 10 a.m. on May 12, 1999, 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:
Kevin G. Fitzgerald
Director of Investor Relations
Murphy Oil Corporation
P. O. Box 7000
El Dorado, Arkansas 71731-7000
(870) 864-6272

ELECTRONIC PAYMENT OF DIVIDENDS
Shareholders may have dividends deposited directly into their bank accounts by electronic funds transfer. Authorization forms may be obtained from:
Harris Trust and Savings Bank
P. O. Box 830
Chicago, Illinois 60690-9972
(312) 461-2457

MURPHY OIL CORPORATION - CIK 0000717423
Appendix to Electronically Filed Exhibit 13
(1998 Annual Report to Security Holders, Which is Incorporated in This Form 10-K) Providing a Narrative of Graphic and Image Material Appearing on Pages 1 Through 20 of Paper Format

Exhibit 13 Page No.	Map Narrative
8	Gulf of Mexico - The locations and areal extent of acreage leased by the Company in the Gulf of Mexico (offshore Texas, Louisiana, Mississippi, Alabama and Florida) are shown. Each lease is colored to denote either (1) production or (2) exploration.
12	Western Canada - The locations of the Company's productive oil and gas fields in the Canadian provinces of British Columbia, Alberta, Saskatchewan and Manitoba are shown. Each field is colored to denote (1) natural gas, (2) light oil, (3) heavy oil, or (4) oil sands.
14	United Kingdom - The locations and areal extent of acreage under license by the Company are shown in the U.K. sector of the North Sea and the Atlantic Margin area west of Britain and Ireland. Each lease is colored to denote either (1) production or (2) exploration.
14	Malaysia - The locations and areal extent of the Company's recently acquired Malaysian acreage offshore Sarawak and Sabah are shown.
16	Wal-Mart Sites Operational as of February 1999 - The locations of the Company's 35 gasoline stations in the parking areas of Wal-Mart stores in the southeastern United States are shown.
18	United States - The locations of the Company's refineries in Superior, Wisconsin and Meraux, Louisiana are shown along with depictions of the routes and means of moving finished products from the refineries into marketing areas and depictions of the locations of terminal facilities used to store and/or distribute products to retail outlets, wholesalers and consumers in the Upper Midwest and the Southeast.
19	United Kingdom - The Company's jointly owned refinery in Milford Haven, Wales is shown along with depictions of the routes and means of moving finished products from the refinery into U.K. marketing areas and depictions of the locations of terminal facilities used to store and/or distribute products to retail outlets, wholesalers and consumers.

Appendix to Electronically Filed Exhibit 13 (Contd.)

Exhibit 13 Page No.	Picture Narrative
4	Claiborne P. Deming, President and Chief Executive Officer of Murphy Oil Corporation, is pictured.
7	A nighttime view of the production platform for the Hibernia oil field offshore eastern Canada is shown.
9	A semisubmersible drilling rig is shown at Ewing Bank Block 994 in the deepwater Gulf of Mexico. This successful well resulted in an important discovery for the Company in 1998.
10	An onshore drilling rig is shown completing the successful Guidry No. 1 well in Vermilion Parish, Louisiana. This well will likely prove up 50 billion cubic feet of reserves.
12	A view is shown of the processing and upgrading facility at Syncrude Canada Ltd. near Fort McMurray, Alberta. Based on current expansion plans, total synthetic oil production at Syncrude will increase to 400,000 barrels a day by 2007.
13	The floating production storage and offloading vessel on location at the Schiehallion field west of the Shetland Islands is shown.
13	The Mungo field's unmanned production platform, flanked by a jack-up rig used to continue development drilling, is shown on location in the U.K. North Sea.
15	An oil processing facility in Block 16 Ecuador is shown. Murphy's production in Ecuador could increase significantly upon completion of a planned crude oil pipeline expansion.
16	A Murphy USA station located in the parking area of the Wal-Mart Supercenter in Callaway, Florida is shown. The Company will significantly expand the number of its stations at Wal-Mart stores during 1999.
17	Processing units are shown at the Company's Meraux, Louisiana refinery, which posted its fourth consecutive record for annual crude oil throughput in 1998.
19	Storage tanks and a ship fueling at the Company's new marine terminal at Duluth, Minnesota are shown. The terminal was opened in 1998 to service shipping traffic on Lake Superior.

Appendix to Electronically Filed Exhibit 13 (Contd.)

Exhibit 13 Page No.	Picture Narrative (Contd.)
20	Claiborne Deming, President and CEO, is shown presenting Judy Quick, an employee at the Company's Meraux refinery, with the 1998 Community Spirit Award in recognition of her outstanding volunteer activities as an employee at the refinery.

Graph Narrative

1 INCOME CONTRIBUTION FROM CONTINUING OPERATIONS BY FUNCTION
Excludes special items and Corporate activities.
Scale 0 to 160 (millions of dollars)

	1994	1995	1996	1997	1998
Refining, Marketing and Transportation (top)	30	2	14	57	49
Exploration and Production (bottom)	45	30	102	85	6
Totals	75	32	116	142	55

This stacked vertical bar graph has totals printed above bars.

1 ESTIMATED NET PROVED HYDROCARBON RESERVES
Scale 0 to 450 (millions of oil equivalent barrels)

	1994	1995	1996	1997	1998
Ecuador and Other (top)	36	30	27	31	32
United Kingdom	30	48	58	63	63
Canada	166	159	157	176	188
United States (bottom)	96	97	96	92	97
Totals	328	334	338	362	380

This stacked vertical bar graph has totals printed above bars.

2 CASH FLOW FROM CONTINUING OPERATIONS BY FUNCTION
Excludes special items, Corporate activities, and changes in noncash working capital.
Scale 0 to 500 (millions of dollars)

	1994	1995	1996	1997	1998
Refining, Marketing and Transportation (top)	38	51	59	100	89
Exploration and Production (bottom)	316	270	343	365	268
Totals	354	321	402	465	357

This stacked vertical bar graph has totals printed above bars.

Exhibit 13 Page No.	Graph Narrative (Continued)					
2	CAPITAL EXPENDITURES BY FUNCTION Scale 0 to 500 (millions of dollars)					
		1994	1995	1996	1997	1998
	Corporate (top)	5	2	1	7	2
	Refining, Marketing and Transportation	95	53	43	38	55
	Exploration and Production (bottom)	286	232	374	423	332
	Totals	386	287	418	468	389
	This stacked vertical bar graph has totals printed above bars.					
4	HYDROCARBON PRODUCTION REPLACEMENT Scale 0 to 180 (percent of production)					
		1994	1995	1996	1997	1998
		147	117	111	165	150
	This vertical bar graph has values printed above bars.					
6	NET HYDROCARBONS PRODUCED Scale 0 to 120 (thousands of oil equivalent barrels a day)					
		1994	1995	1996	1997	1998
	Ecuador and Other (top)	5	7	7	8	8
	United Kingdom	15	17	16	16	18
	Canada	28	30	30	32	36
	United States (bottom)	46	45	37	46	36
	Totals	94	99	90	102	98
	This stacked vertical bar graph has totals printed above bars.					
10	CAPITAL EXPENDITURES - EXPLORATION AND PRODUCTION Scale 0 to 480 (millions of dollars)					
		1994	1995	1996	1997	1998
	Ecuador and Other (top)	62	29	21	38	32
	United Kingdom	34	33	69	91	71
	Canada	111	99	99	147	108
	United States (bottom)	79	71	185	147	121
	Totals	286	232	374	423	332
	This stacked vertical bar graph has values printed above bars.					
11	WORLDWIDE EXTRACTION COSTS Scale 0 to 10.50 (dollars per equivalent barrel)					
		1994	1995	1996	1997	1998
	Depreciation, Depletion and Amortization (top)	4.71	5.06	4.48	4.62	4.58
	Production Expense (bottom)	4.72	4.64	4.87	4.41	4.35
	Totals	9.43	9.70	9.35	9.03	8.93
	This stacked vertical bar graph has values for each component printed within bars and totals printed above bars.					

Exhibit 13 Page No.	Graph Narrative (Continued)
18	CAPITAL EXPENDITURES - REFINING, MARKETING AND TRANSPORTATION

Scale 0 to 120 (millions of dollars)

	1994	1995	1996	1997	1998
Canada (top)	3	4	8	5	3
United Kingdom	12	22	14	4	7
United States (bottom)	80	28	21	29	45
Totals	95	54	43	38	55

This stacked vertical bar graph has totals printed above bars.

19 REFINED PRODUCTS SOLD

Scale 0 to 200 (thousands of barrels a day)

	1994	1995	1996	1997	1998
United Kingdom (top)	40	31	33	29	36
United States (bottom)	114	127	128	134	138
Totals	154	158	161	163	174

This stacked vertical bar graph has totals printed above bars.

EXHIBIT 21

MURPHY OIL CORPORATION

SUBSIDIARIES OF THE REGISTRANT AS OF DECEMBER 31, 1998

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
MURPHY OIL CORPORATION (REGISTRANT)		
A. El Dorado Engineering Inc.	Delaware	100.0
1. El Dorado Contractors Inc.	Delaware	100.0
B. Murphy Eastern Oil Company	Delaware	100.0
C. Murphy Exploration & Production Company (formerly Ocean Drilling & Exploration 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
b. Ocean Drilling 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. MEPCO Venezuela, Ltd.	Bahamas	100.0
6. Murphy Bangladesh Oil Company	Delaware	100.0
7. Murphy Brazil Exploracao e Producao de Petroleo e Gas Ltda. (see company C21a below)	Brazil	90.0
8. Murphy Building Corporation	Delaware	100.0
9. Murphy Central Asia Oil Co., Ltd.	Bahamas	100.0
10. Murphy Denmark Oil Company	Delaware	100.0
11. Murphy Ecuador Oil Company Ltd.	Bermuda	100.0
12. Murphy Equatorial Guinea Oil Company	Delaware	100.0
13. Murphy Exploration (Alaska), Inc.	Delaware	100.0
14. Murphy Falklands Oil Co., Ltd.	Bahamas	100.0
15. Murphy Faroes Oil Co., Ltd.	Bahamas	100.0
16. Murphy France Oil Company	Delaware	100.0
17. Murphy Indus Energy Ltd.	Bahamas	100.0
18. Murphy Ireland Oil Company	Delaware	100.0
19. Murphy Italy Oil Company	Delaware	100.0
20. Murphy New Zealand Oil Company	Delaware	100.0
21. Murphy Overseas Ventures Inc.	Delaware	100.0
a. Murphy Brazil Exploracao e Producao de Petroleo e Gas Ltda. (see company C7 above)	Brazil	10.0
22. Murphy Pacific Rim, Ltd.	Bahamas	100.0
23. Murphy Pakistan Oil Company	Delaware	100.0
24. Murphy Philippines Oil Co., Ltd.	Bahamas	100.0
25. Murphy Sabah Oil Co., Ltd.	Bahamas	100.0
26. Murphy Sarawak Oil Co., Ltd.	Bahamas	100.0
27. Murphy Somali Oil Company	Delaware	100.0
28. Murphy South Asia Oil Co., Ltd.	Bahamas	100.0
29. Murphy South Atlantic Oil Company	Delaware	100.0

MURPHY OIL CORPORATION

SUBSIDIARIES OF THE REGISTRANT AS OF DECEMBER 31, 1998 (Contd.)

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
MURPHY OIL CORPORATION (REGISTRANT) - Contd.		
C. Murphy Exploration & Production Company - Contd.		
30. Murphy-Spain Oil Company	Delaware	100.0
31. Murphy Venezuela Oil Company, S.A.	Panama	100.0
32. Murphy Western Oil Company	Delaware	100.0
33. Murphy Yemen Oil Company	Delaware	100.0
34. Norske Murphy Oil Company	Delaware	100.0
35. Norske Ocean Exploration Company	Delaware	100.0
36. Ocean Exploration Company	Delaware	100.0
37. Ocean France Oil Company	Delaware	100.0
38. Ocean Gabon Oil Company	Delaware	100.0
39. Ocean International Finance Corporation	Delaware	100.0
40. Odeco Drilling (UK) Limited	England	100.0
41. Odeco Gabon Oil Company	Delaware	100.0
42. Odeco International Corporation	Panama	100.0
43. Odeco Italy Oil Company	Delaware	100.0
44. Sub Sea Offshore (M) Sdn. Bhd.	Malaysia	60.0
D. Murphy Oil Company, Ltd.	Canada	100.0
1. 340236 Alberta Ltd.	Canada	100.0
2. Murphy Atlantic Offshore Finance Company Ltd.	Canada	100.0
3. Murphy Atlantic Offshore Oil Company Ltd.	Canada	100.0
4. Spur Refined Products Ltd.	Canada	100.0
5. Wascana Pipe Line Ltd.	Canada	100.0
E. Murphy Oil USA, Inc.	Delaware	100.0
1. Arkansas Oil Company	Delaware	100.0
2. Murphy Gas Gathering Inc.	Delaware	100.0
3. Murphy Latin America Refining & Marketing, Inc.	Delaware	100.0
4. Murphy LOOP, Inc.	Delaware	100.0
5. Murphy Oil Trading Company (Eastern)	Delaware	100.0
6. Spur Oil Corporation	Delaware	100.0
7. Superior Crude Oil Trading Company	Delaware	100.0
F. Murphy Realty Inc.	Delaware	100.0
G. Murphy Ventures Corporation	Delaware	100.0
H. 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
I. Rowel Corporation	Delaware	100.0

INDEPENDENT AUDITORS' CONSENT

The Board of Directors
Murphy Oil Corporation:

We consent to incorporation by reference in the Registration Statements (Nos. 2-82818, 2-86749, 2-86760, and 333-27407) on Form S-8 and (No. 33-55161) on Form S-3 of Murphy Oil Corporation of our report dated March 1, 1999, relating to the consolidated balance sheets of Murphy Oil Corporation and Consolidated Subsidiaries as of December 31, 1998 and 1997, 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, 1998, which report is included in the December 31, 1998, annual report on Form 10-K of Murphy Oil Corporation.

KPMG LLP

Shreveport, Louisiana
March 24, 1999

THIS FINANCIAL DATA SCHEDULE CONTAINS SUMMARY FINANCIAL INFORMATION EXTRACTED FROM THE AUDITED CONSOLIDATED BALANCE SHEET AT DECEMBER 31, 1998, AND THE AUDITED CONSOLIDATED STATEMENT OF INCOME FOR THE YEAR ENDED DECEMBER 31, 1998, OF MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES AND IS QUALIFIED IN ITS ENTIRETY BY REFERENCE TO SUCH FINANCIAL STATEMENTS.

1,000

YEAR
DEC-31-1998
DEC-31-1998
28,271
0
244,954
11,048
129,777
437,366
4,648,216
2,985,854
2,164,419
380,750
333,473
0
0
48,775
929,458
2,164,419
1,624,980
1,698,848
1,482,314
1,482,314
145,709
0
10,484
(8,277)
6,117
(14,394)
0
0
0
(14,394)
(.32)
(.32)

INCLUDES 80,127 FOR IMPAIRMENT OF LONG-LIVED ASSETS.

UNDERTAKINGS

To be incorporated by reference into Form S-8 Registration Statements Nos. 2-82818, 2-86749, 2-86760, and 333-27407, and Form S-3 Registration Statement No. 33-55161.

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.