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

FORM 10-K

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

For the fiscal year ended DECEMBER 31, 1993

or

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

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 (501) 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. [X] Yes [_] No.

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

Aggregate market value of the voting stock held by non-affiliates of the registrant, based on average price at February 28, 1994 as quoted by the New York Stock Exchange, was approximately $1,276,693,000.

Number of shares of Common Stock, $1.00 Par Value, outstanding at February 28, 1994, was 44,806,705.

Documents incorporated by reference

The Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 11, 1994 (Part III)

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TABLE OF CONTENTS--1993 FORM 10-K REPORT

PART I

ITEMS 1. AND 2. BUSINESS AND PROPERTIES.

Murphy Oil Corporation is a natural resources company that operates through subsidiaries in the United States and internationally to conduct the various business activities of the enterprise. As used in this report, the terms Murphy, we, our, its, and Company may refer to any one or more of the consolidated subsidiaries as well as to Murphy Oil Corporation.

The Company was originally incorporated in Louisiana in 1950 as Murphy Corporation; reincorporated in Delaware in 1964, at which time it adopted the name Murphy Oil Corporation; and reorganized in 1983 to operate solely as a holding company of its various businesses. Its activities are classified into two business segments: (1) "Petroleum," which comprises its international integrated oil and gas operations and is further subdivided into "Exploration and Production" and "Refining, Marketing, and Transportation," and (2) "Farm, Timber, and Real Estate," which has operations primarily in Arkansas and North Louisiana. Additionally, "Corporate and Other" activities include interest income, interest expense, and overhead not allocated to business segments.

The information appearing on pages 4 through 62 of the 1993 Annual Report to Security Holders (1993 Annual Report) is incorporated in this Annual Report on Form 10-K as Exhibit 13 and is deemed to be filed as part of this 10-K report as indicated under Items 1, 2, 3, 5, 6, 7, 8, and 14. A narrative of the graphic and image information that appears in the paper format version of Exhibit 13 on pages 4 through 62 is included in the electronic Form 10-K document as an appendix to Exhibit 13 (pages A-1 through A-9).

In addition to the following information about each business segment, data relative to Murphy's continuing operations, properties, and industry segments, including revenues by class of products and financial information by geographic areas, are described on pages 23 through 30 and 50 through 53 of the 1993 Annual Report, which is filed in this 10-K report as Exhibit 13.

PETROLEUM--EXPLORATION AND PRODUCTION

During 1993, Murphy's principal exploration and/or production activities were conducted in the United States, Ecuador, Spain, Gabon, and Peru by Murphy Exploration & Production Company (Murphy Expro) and its subsidiaries; in Canada by Murphy Oil Company Ltd. (MOCL); and in the U.K. North Sea by Murphy Petroleum Limited. Murphy's crude oil and natural gas liquids production is in the United States, Canada, the U.K. North Sea, Gabon, and Spain; its natural gas is produced and sold in the United States, Canada, the U.K. North Sea, and Spain. In December 1993, MOCL acquired a five-percent interest in a project (Syncrude) that extracts synthetic crude oil from oil sand deposits in northern Alberta.

Murphy's estimated net quantities of proved oil and gas reserves and proved developed oil and gas reserves at January 1, 1991 and at December 31, 1991, 1992, and 1993 by geographic area are reported on pages 55 and 56 of the 1993 Annual Report, which is filed in this 10-K report as Exhibit 13. Murphy has not filed, and is not required to file, any estimates of its total proved net oil or gas reserves on a recurring basis with any federal or foreign governmental regulatory authority or agency other than the SEC. Annually, Murphy reports gross reserves of U.S. operated properties to the U.S. Department of Energy; such reserves are derived from the same data from which estimated total proved net reserves of such properties are determined.

In 1993, essentially all of Murphy's U.S. crude oil, condensate, and natural gas liquids production was delivered, either directly or indirectly through exchanges, to its own refineries. 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, 1993 appear on page 60 of the 1993 Annual Report, which is filed in this 10-K report as Exhibit 13.

PETROLEUM - EXPLORATION AND PRODUCTION (Contd.)

Production costs in U.S. dollars per equivalent barrel produced, including natural gas volumes converted to equivalent barrels of crude oil on the basis of approximate relative energy content, are shown in the following table.

Year	United States	Canada	United Kingdom	Ecuador	Other
1993	$ 3.21	3.70	6.80	-	8.42
1992	3.00	4.18	8.73	-	7.01
1991	3.42	4.90	7.25	-	3.62

Supplemental disclosures about oil and gas producing activities are reported on pages 54 through 59 of the 1993 Annual Report, which is filed in this report as Exhibit 13.

At December 31, 1993, Murphy held leases, concessions, or permits on nonproducing and producing acreage in the following countries (thousands of acres).

	Nonproducing		Producing		Total	
Country	Gross	Net	Gross	Net	Gross	Net
United State - Onshore	79	36	285	60	364	96
- Gulf of Mexico	600	352	442	162	1,042	514
- Frontier	259	139	-	-	259	139
Total United States	938	527	727	222	1,665	749
Canada - Onshore	748	346	443	180	1,191	526
- Offshore	83	5	-	-	83	5
- Oil sands	126	42	27	3	153	45
Total Canada	957	393	470	183	1,427	576
United Kingdom	615	124	80	11	695	135
Gabon	2	-	34	9	36	9
Spain	61	11	28	5	89	16
Ecuador	494	99	-	-	494	99
Pakistan	6,720	6,720	-	-	6,720	6,720
Peru	2,471	988	-	-	2,471	988
Somalia	4,023	402	-	-	4,023	402
Tunisia	165	42	-	-	165	42
Totals	16,446	9,306	1,339	430	17,785	9,736

Oil and gas wells producing or capable of producing at December 31, 1993 are summarized as follows.

	Oil Wells		Gas Wells	
Country	Gross	Net	Gross	Net
United States	1,585	567.9	426	146.4
Canada	4,041	630.0	607	206.0
United Kingdom	80	7.9	16	1.1
Gabon	7	3.1	-	-
Spain	-	-	2	.3
Ecuador (under development)	13	2.6	-	-
Totals	5,726	1,211.5	1,051	353.8
Wells included above with multiple completions and counted as one well each	120	49.9	115	65.4

Gross wells are wells 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.

PETROLEUM - EXPLORATION AND PRODUCTION (Contd.)

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

	United States		Canada		United Kingdom		Ecuador		Other		Totals	
	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry
1993												
Exploratory	7.4	6.5	3.9	4.2	.1	-	-	-	-	.5	11.4	11.2
Development	4.1	-	24.5	2.7	.7	.1	1.2	-	-	-	30.5	2.8
1992												
Exploratory	7.8	5.2	3.1	1.3	.5	1.0	-	-	-	1.0	11.4	8.5
Development	2.2	-	18.4	1.3	.3	-	-	-	-	-	20.9	1.3
1991												
Exploratory	13.4	5.3	3.7	5.0	.3	1.1	-	-	.3	.3	17.7	11.7
Development	1.7	.6	7.7	1.9	.3	-	-	-	-	-	9.7	2.5

The wells that Murphy was drilling at December 31, 1993 are summarized as follows.

	Exploratory		Development		Totals	
Country	Gross	Net	Gross	Net	Gross	Net
United States	4	1.6	-	-	4	1.6
Canada	5	2.5	5	3.1	10	5.6
United Kingdom	2	.4	-	-	2	.4
Totals	11	4.5	5	3.1	16	7.6

Additional information about current exploration and production activities is reported on pages 4 through 14 of the 1993 Annual Report, which is filed in this 10-K report as Exhibit 13.

PETROLEUM - REFINING, MARKETING, AND TRANSPORTATION

Murphy Oil USA, Inc. (Murphy USA), a wholly owned subsidiary, owns and operates two refineries in the United States. The refinery at Superior, Wisconsin, is located on fee land. The Meraux, Louisiana, refinery is located on both fee and leased land; these leases expire at varying times from 2010 to 2022, and at such times the Company has options to purchase all leased acreage at fixed prices. Murco Petroleum Limited (Murco), a wholly owned U.K. subsidiary serviced by Murphy Eastern Oil Company, has an effective 30-percent interest in a 108,000-barrel-a-day refinery at Milford Haven, Wales. Refinery capacities at December 31, 1993 are shown in the following table.

	Meraux, Louisiana	Superior, Wisconsin	Milford Haven, Wales (Murco's 30%)	Totals
Crude capacity - b/sd*	100,000	35,000	32,400	167,400
Process capacities - b/sd*				
Vacuum distillation	40,000	20,000	16,500	76,500
Catalytic cracking - fresh feed	40,000	11,000	9,960	60,960
Pretreating cat-reforming feeds	29,000	9,000	5,400	43,400
Catalytic reforming	23,000	8,000	5,400	36,400
Distillate hydrotreating	15,000	5,800	9,000	29,800
Gas oil hydrotreating	28,000	-	-	28,000
Solvent deasphalting	14,000	-	-	14,000
Isomerization	-	2,000	2,250	4,250
Production capacities - b/sd*				
Alkylation	9,500	1,600	1,680	12,780
Asphalt	-	13,500	-	13,500
Crude oil and product storage capacities - bbls.	4,257,000	2,852,000	2,638,000	9,747,000

*Barrels per stream day.

Murphy distributes refined products in the U.S. (by Murphy USA) and Canada (by MOCL) under the brand name SPUR and to unbranded wholesale accounts from 47 terminals. Four of these are marine terminals, two are supplied by truck, two are adjacent to the refineries, and 38 are supplied by pipeline. Eight terminals are wholly owned and operated by Murphy USA, 15 are jointly owned and operated by others, and the remaining 24 are owned by others. Murphy USA 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 1993, refined products were marketed at wholesale and/or retail through 606 branded outlets in 14 southeastern and upper midwestern states and eight branded outlets in the Thunder Bay area of Ontario, Canada.

At the end of 1993, Murco distributed refined products in the United Kingdom through three wholly owned terminals, 10 terminals owned by others where products are received in exchange for deliveries from the Company's wholly owned terminals, and 428 retail outlets under the brand names MURCO and EP.

Murphy owns a 20-percent interest in a 120-mile, 165,000-barrel-a-day refined products pipeline 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-percent 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-percent interest in LOOP Inc., which provides deep-water off-loading accommodations off the Louisiana coast for oil tankers and onshore facilities for storage of crude oil. In addition, Murphy owns 29.4 percent of a 22-mile, 300,000-barrel-a-day crude oil pipeline between LOOP storage at Clovelly, Louisiana, and Alliance, Louisiana, and 100 percent of a 24-mile, 200,000-barrel-a-day crude oil pipeline from Alliance to the Meraux refinery. The pipeline from Alliance to Meraux is also connected to another company's pipeline system, thus allowing crude oil from wells serviced by that system to be shipped to the refinery.

MOCL has a 52.5-percent interest in a 114-mile dual pipeline in Canada that transports heavy crude oil from Blackfoot, Alberta, to Kerrobert, Saskatchewan, where access to a major crude trunk line is available. This pipeline has a throughput capacity of 50,000 barrels a day. MOCL also owns a 13.1-percent interest in a 40-mile, 38,000-barrel-a-day dual pipeline to transport heavy crude oil from Cactus Lake, Saskatchewan, to Kerrobert; a 26.3-percent interest in a 15-mile, 9,000-barrel-a-day dual crude oil pipeline from Bodo, Alberta, to Cactus Lake; a 100-percent interest in a 10.5-mile, 48,000-barrel-a-day dual crude oil pipeline from Milk River, Alberta, to the U.S. border; a 100-percent interest in a 108-mile, 36,000-barrel-a-day crude oil pipeline from Regina, Saskatchewan, to the U.S. border; and a 100-percent interest in a 28-mile, 15,000-barrel-a-day heavy crude oil pipeline from Eyehill, Saskatchewan, to Unity, Saskatchewan. MOCL is operator of these pipelines.

PETROLEUM--REFINING, MARKETING, AND TRANSPORTATION (Contd.)

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, 1993 are reported on pages 15 through 20 and 61 of the 1993 Annual Report, which is filed in this 10-K report as Exhibit 13.

FARM, TIMBER, AND REAL ESTATE

Deltic Farm & Timber Co. Inc. (Deltic), a wholly owned subsidiary, is engaged in farming and timber and land management in Arkansas and North Louisiana, lumber manufacturing and marketing in Arkansas, and real estate development in western Little Rock, Arkansas.

Deltic owns sawmills at Ola in central Arkansas and at Waldo in southern Arkansas. The mills have a combined annual capacity to produce 122.6 million board feet of lumber. The Ola mill is designed for maximum utilization of small stem timber, while the Waldo mill can process both small and large diameter timber.

Deltic owned 341,000 acres of timberland at year-end 1993. Its estimated standing timber inventories on this acreage are calculated for each tract by utilizing growth formulas based on representative sample tracts and tree counts for various diameter classifications. The calculations of pine inventories are subject to periodic adjustments based on sample cruises or actual volumes harvested from related tracts. The hardwood inventories shown in the following table are only approximations, so physical quantities of such timber may vary significantly from these approximations. Estimated inventories of standing timber at year-end for each of the last three years were as follows.

	1993	1992	1991
Pine sawtimber - MBF*	810,162	805,260	766,130
Hardwood sawtimber - MBF*	113,290	114,000	111,104
Pine pulpwood - cords	962,563	940,477	988,790
Hardwood pulpwood - cords	417,293	448,100	436,208

*Thousand board feet - Doyle scale.

At Deltic's farms, which comprise 36,000 acres in northeastern Louisiana and southeastern Arkansas, the primary crops grown and harvested are cotton, soybeans, corn, wheat, and rice. In recent years, Deltic has been developing in stages a 4,300-acre planned community centered around an 18-hole golf course (voted in 1991 by "Golf Digest" as being one of the three best new private courses in the United States) and selling real estate, primarily residential lots thus far, in this area of western Little Rock, Arkansas. The golf course and associated country club are in a nonprofit corporation not owned by the Company.

Additional information about current farm, timber, and real estate activities and a statistical summary of key operating and financial indicators for each of the five years ended December 31, 1993 are reported on pages 21, 22, and 62 of the 1993 Annual Report, which is filed in this 10-K report as Exhibit 13.

DISCONTINUED OPERATIONS

Prior to the sale effective January 1, 1992 of its wholly owned subsidiary Odeco Drilling Inc., Murphy was engaged in contract drilling in offshore waters throughout the world. Further information about the sale is reported by Note D on page 39 of the 1993 Annual Report, which is filed in this 10-K report as Exhibit 13.

Effective December 31, 1984, Murphy Expro, at that time named Ocean Drilling & Exploration Company (ODECO) and owned 59.4 percent by Murphy, elected to cease the operations of Mentor Insurance Limited, its wholly owned subsidiary that was engaged in the international insurance and reinsurance business. Events related to the liquidation of this business are reported by Note E on page 39 of the 1993 Annual Report, which is filed in this 10-K report as Exhibit 13.

EMPLOYEES

Murphy had 1,803 full-time employees at December 31, 1993.

COMPETITION AND OTHER CONDITIONS WHICH MAY AFFECT BUSINESS

Murphy operates principally in the oil industry, in which it 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.

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 fixing prices and determining rates of production and who may sell and buy the production. Until 1993, the United States also regulated prices for certain categories of natural gas 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 of the environment (See Management's Discussion and Analysis - Environmental Obligations, page 30 of the 1993 Annual Report, which is filed in this 10-K report as Exhibit 13.), 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 government-influenced factors too numerous to list are subject to constant changes dictated by 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 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 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, 1994), present corporate office, and length of service in office of each of the Company's executive officers and persons chosen to become 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.

C. H. Murphy Jr - Age 73; Chairman of the Board since 1972. He has been a Director and Member of the Executive Committee since incorporation of the Company in 1950 and was Chief Executive Officer from incorporation until 1984.

Jack W. McNutt - Age 59; President, Chief Executive Officer, Director, and Member of the Executive Committee since 1988. Mr. McNutt was Executive Vice President, Director, and Member of the Executive Committee from 1981 to 1988; he was named Chief Operating Officer in 1986.

Claiborne P. Deming - Age 39; Executive Vice President and Chief Operating Officer, Director, and Member of the Executive Committee since February 1993. Mr. Deming had been Executive Vice President and Chief Operating Officer since March 1992. Prior to that, he was President of Murphy USA from 1989 to 1992 and Vice President, Petroleum Operations, for Murphy from 1988 to 1989.

R. Madison Murphy - Age 36; Executive Vice President and Chief Financial and Administrative Officer, Director, and member of the Executive Committee since February 1993. Mr. Murphy had been Executive Vice President and Chief Financial Officer since March 1992. Prior to that, he was 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.

EXECUTIVE OFFICERS OF THE REGISTRANT (Contd.)

Steven A. Cosse - Age 46; Vice President and General Counsel since February 1993. Mr. Cosse was General Counsel from August 1991 to February 1993. For the eight years prior to that, he was General Counsel for ODECO.

Odie F. Vaughan - Age 57; Treasurer since August 1991. From 1975 through July 1991, he was with ODECO as Vice President of Taxes and Treasurer.

Ronald W. Herman - Age 56; Controller since August 1991. He was Controller of ODECO from 1977 through July 1991.

W. Bayless Rowe - Age 41; Secretary and General Attorney since 1988. He has been an attorney with the Company since 1977.

ITEM 3. LEGAL PROCEEDINGS.

Information contained in Note E, page 39, and Note S, pages 49 through 50, of the 1993 Annual Report, which is filed in this 10-K report as Exhibit 13, is incorporated herein. Also, Murphy Oil USA, Inc., which owns and operates two oil refineries in the U.S., is a defendant in three governmental actions that: (1) seek monetary sanctions of $100,000 or more, and (2) arise under enacted provisions that regulate the discharge of materials into the environment or have the purpose of protecting the environment. These actions individually or in the aggregate are not material to the financial condition of the Company. In addition, 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 material as defined.

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 1993.

PART II

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

Information required by this item is reported on pages 31 and 44 through 46, Notes K and L, of the 1993 Annual Report, which is filed in this 10-K report as Exhibit 13.

ITEM 6. SELECTED FINANCIAL DATA.

Information required by this item appears on page 23 of the 1993 Annual Report, which is filed in this 10-K report as Exhibit 13.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION.

Information required by this item appears on pages 24 through 30 of the 1993 Annual Report, which is filed in this 10-K report as Exhibit 13.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Information required by this item appears on pages 31 through 59 of the 1993 Annual Report, which is filed in this 10-K report as Exhibit 13.

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 in Part I, pages 8 and 9, of this 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 11, 1994, under the caption "Election of Directors."

ITEM 11. EXECUTIVE COMPENSATION.

Information is incorporated by reference to the Registrant's definitive proxy statement for the annual meeting of stockholders on May 11, 1994, under the captions "Compensation of Directors," "Executive Compensation," "Option Exercises and Fiscal Year-End Values," "Option Grants," "Compensation Committee Report for 1993," "Shareholder Return Performance Presentation," and "Retirement Plans."

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

Information is incorporated by reference to the Registrant's definitive proxy statement for the annual meeting of stockholders on May 11, 1994, under the caption "Certain Stock Ownerships."

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

Information is incorporated by reference to the Registrant's definitive proxy statement for the annual meeting of stockholders on May 11, 1994, under the caption "Compensation Committee Interlocks and Insider Participation."

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K.

(a) 1. FINANCIAL STATEMENTS

The following consolidated financial statements of Murphy Oil Corporation and consolidated subsidiaries are included on the pages indicated of Exhibit 13 to this 10- K report.

	Exhibit 13 Page Nos.
Independent Auditors' Report	32
Consolidated Statements of Income	33
Consolidated Balance Sheets	34
Consolidated Statements of Cash Flows	35
Consolidated Statements of Stockholders' Equity	36
Notes to Consolidated Financial Statements	37 through 53

(a) 2. FINANCIAL STATEMENT SCHEDULES

The following financial statement schedules of Murphy Oil Corporation and consolidated subsidiaries are included in this 10-K report on the pages as indicated below. All other schedules are omitted because either they are not applicable or the required information is included in the consolidated financial statements or notes thereto.

	10-K Page Nos.
Independent Auditors' Report on Schedules	12
Schedule I --Marketable Securities	13
Schedule V --Property, Plant, and Equipment	14
Schedule VI--Accumulated Depreciation, Depletion, and Amortization of Property, Plant, and Equipment	15
Schedule IX--Short-term Borrowings	16
Schedule X --Supplementary Income Statement Information	17

(a) 3. EXHIBITS

The Exhibit Index on page 19 of this 10-K report lists the exhibits that are hereby filed.

(b) REPORTS ON FORM 8-K

No reports on Form 8-K were filed during the quarter ended December 31, 1993.

INDEPENDENT AUDITORS' REPORT ON SCHEDULES

The Board of Directors
Murphy Oil Corporation:

Under date of March 4, 1994, we reported on the consolidated balance sheets of Murphy Oil Corporation and Consolidated Subsidiaries as of December 31, 1993 and 1992, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 1993, as contained in the 1993 annual report to stockholders. These consolidated financial statements and our report thereon are included in Exhibit 13 in the annual report on Form 10-K for the year 1993. In connection with our audits of the aforementioned consolidated financial statements, we also have audited the financial statement schedules as listed under Item 14 (a) 2. These financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statement schedules based on our audits.

In our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note B to the consolidated financial statements, the Company adopted the provisions of Financial Accounting Standards Board's Statement of Financial Accounting Standards No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," and Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes," in 1993.

KPMG PEAT MARWICK

Shreveport, Louisiana
March 4, 1994

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SCHEDULE I - MARKETABLE SECURITIES
December 31, 1993

(Thousands of dollars)

Name of Issuer and Title of Issue	Principal Amount	Cost	Approx. Market Value at Above Date*	Balance Sheet Amount*
United States Government - Treasury bills	$ 91,608	90,620	90,932	90,932
Government of Canada - Treasury bills	8,259	8,227	8,242	8,242
Reverse repurchase agreements	15,170	15,170	15,175	15,175
Total Marketable Securities	$115,037	114,017	114,349	114,349

*Includes accrued interest.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SCHEDULE V--PROPERTY, PLANT, AND EQUIPMENT
Three years ended December 31, 1993

(Thousands of dollars)

Classification	Balance at beginning of period	Additions at cost	Retirements	Other changes - add/(deduct)	Balance at end of period
YEAR ENDED DECEMBER 31, 1991					
Exploration and production	$2,233,477	116,758	27,528	55 (1)	
				111,960 (2)	
				(10,648) (3)	
				161 (4)	
				9,636 (5)	2,433,871
Refining	349,664	44,588	114	8 (1)	
				(1,556) (3)	392,590
Marketing	122,394	15,184	5,769	(20) (1)	
				(1,352) (3)	
				853 (6)	131,290
Transportation	57,666	3,371	46	(43) (1)	
				79 (3)	61,027
Farms, timber, and real estate	155,685	2,858	1,923	(5,225) (7)	151,395
Corporate and other	60,220	2,203	324	(48) (3)	62,051
	$2,979,106	184,962	35,704	103,860	3,232,224
YEAR ENDED DECEMBER 31, 1992					
Exploration and production	$2,433,871	115,296	112,353	41,742 (1)	
				(129,363) (3)	
				1,494 (4)	2,350,687
Refining	392,590	47,942	224	(21,011) (3)	419,297
Marketing	131,290	14,111	3,592	(12,462) (3)	129,347
Transportation	61,027	6,020	125	(5,026) (1)	
				(2,997) (3)	58,899
Farms, timber, and real estate	151,395	6,017	2,619	(928) (7)	153,865
Corporate and other	62,051	1,477	362	(36,716) (1)	
				(878) (3)	25,572
	$3,232,224	190,863	119,275	(166,145)	3,137,667
YEAR ENDED DECEMBER 31, 1993					
Exploration and production	$2,350,687	503,018	56,768	(140) (1)	
				(44,585) (3)	
				97 (4)	
				107,515 (8)	
				(828) (9)	2,858,996
Refining	419,297	66,364	58	209 (1)	
				(1,769) (3)	484,043
Marketing	129,347	16,941	4,723	93 (1)	
				(1,180) (3)	140,478
Transportation	58,899	3,580	148	134 (1)	
				(1,337) (3)	
				580 (8)	61,708
Farms, timber, and real estate	153,865	9,674	3,737	(6) (1)	
				(1,045) (7)	
				(11)(10)	158,740
Corporate and other	25,572	4,034	3,089	(291) (1)	
				(209) (3)	26,017
	$3,137,667	603,611	68,523	57,227	3,729,982

(1) Transfers between classifications.
(2) Fair value in excess of book value of properties acquired from minority interest.
(3) Amounts applicable to foreign currency translations.
(4) Depreciation applicable to used well equipment included in purchase of producing properties.
(5) Reclassified from investments.
(6) Cancellation or reclassification of capitalized lease obligations.
(7) Reclassified to investments and deferred charges.
(8) Effect of SFAS No. 109 on prior business combinations.
(9) Reclassified from deferred income tax liability.
(10) Other.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SCHEDULE VI - ACCUMULATED DEPRECIATION, DEPLETION, AND
AMORTIZATION OF PROPERTY, PLANT, AND EQUIPMENT
Three years ended December 31, 1993

(Thousands of dollars)

Classification	Balance at beginning of period	Additions charged to costs and expenses	Retirements	Other changes - add/(deduct)	Balance at end of period
YEAR ENDED DECEMBER 31, 1991					
Exploration and production	$1,593,936	159,448	24,557	(184) (1)	
				(8,397) (2)	
				161 (3)	
				9,128 (4)	1,729,535
Refining	215,012	17,358	95	5 (1)	
				(793) (2)	231,487
Marketing	40,969	5,988	2,370	3 (1)	
				(421) (2)	
				853 (5)	45,022
Transportation	24,375	2,638	35	177 (1)	
				35 (2)	27,190
Farms, timber, and real estate	43,513	3,221	346	-	46,388
Corporate and other	20,476	3,673	257	(1) (1)	
				(29) (2)	
				99 (4)	23,961
	$1,938,281	192,326	27,660	636	2,103,583
YEAR ENDED DECEMBER 31, 1992					
Exploration and production	$1,729,535	147,407	111,051	15,964 (1)	
				(91,893) (2)	
				1,494 (3)	1,691,456
Refining	231,487	20,623	193	(14) (1)	
				(8,487) (2)	243,416
Marketing	45,022	6,696	3,076	45 (1)	
				(4,817) (2)	43,870
Transportation	27,190	2,560	120	(3,220) (1)	
				(1,262) (2)	25,148
Farms, timber, and real estate	46,388	3,120	710	-	48,798
Corporate and other	23,961	1,432	297	(12,775) (1)	
				(644) (2)	
				123 (7)	11,800
	$2,103,583	181,838	115,447	(105,486)	2,064,488
YEAR ENDED DECEMBER 31, 1993					
Exploration and production	$1,691,456	148,689	49,518	(421) (1)	
				(32,965) (2)	
				97 (3)	
				26,003 (6)	1,783,341
Refining	243,416	19,873	56	119 (1)	
				(764) (2)	262,588
Marketing	43,870	7,014	4,552	20 (1)	
				(432) (2)	45,920
Transportation	25,148	2,698	101	433 (1)	
				(552) (2)	27,626
Farms, timber, and real estate	48,798	3,500	1,381	(11) (7)	50,906
Corporate and other	11,800	1,582	2,709	(151) (1)	
				(171) (2)	10,351
	$2,064,488	183,356	58,317	(8,795)	2,180,732

(1) Transfers between classifications.
(2) Amounts applicable to foreign currency translations.
(3) Depreciation applicable to used well equipment included in purchase of producing properties.
(4) Reclassified from investments.
(5) Cancellation or reclassification of capitalized lease obligations.
(6) Effect of SFAS No. 109 on prior business combinations.
(7) Other.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SCHEDULE IX - SHORT-TERM BORROWINGS
Three years ended December 31, 1993

(Thousands of dollars)

	At end of period		Outstanding during the period		
Category of aggregate short-term borrowings	Balance (1)	Weighted average interest rate	Maximum amount	Average amount (2)	Weighted average interest rate (2)
Year ended December 31, 1991					
Payable to banks for borrowings	$ 37,680	6.2%	$ 88,663	15,576	7.7%
Year ended December 31, 1992					
Payable to banks for borrowings	2,795	7.2% (3)	123,886	27,418	5.7%
Year ended December 31, 1993					
Payable to banks for borrowings	-	-%	3,104	1,355	6.2%

(1) The unused lines of credit can be withdrawn by the banks at any time. Outstanding amounts are normally repayable within one year and bear interest based on the banks' prime lending rates or costs of funds rates.

(2) Average interest rates and average amounts outstanding are based on daily rates and amounts.

(3) Primarily borrowings in the U.K., with a corresponding deposit earning interest at a rate that may be up to .5% lower.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SCHEDULE X - SUPPLEMENTARY INCOME STATEMENT INFORMATION
Three years ended December 31, 1993

(Thousands of dollars)

Item	Charged to Costs and Expenses 1993	1992	1991
Maintenance and repairs	$88,618	90,238	72,840

No other items required to be reported on this schedule exceeded one percent of total revenues.

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 JACK W. McNUTT
Jack W. McNutt, President

Date: March 29, 1994

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on March 29, 1994 by the following persons on behalf of the registrant and in the capacities indicated.

C. H. MURPHY JR.
C. H. Murphy Jr., Chairman of the Board and Director

VESTER T. HUGHES JR.
Vester T. Hughes Jr., Director

JACK W. McNUTT
Jack W. McNutt, President and Director (Principal Executive Officer)

MICHAEL W. MURPHY
Michael W. Murphy, Director

CLAIBORNE P. DEMING
Claiborne P. Deming, Executive Vice President and Director

WILLIAM C. NOLAN JR.
William C. Nolan Jr., Director

R. MADISON MURPHY
R. Madison Murphy, Executive Vice President and Chief Financial and Administrative Officer and Director (Principal Financial Officer)

CAROLINE G. THEUS
Caroline G. Theus, Director

B. R. R. BUTLER
B. R. R. Butler, Director

LORNE C. WEBSTER
Lorne C. Webster, Director

JOHN W. DEMING
John W. Deming, Director

RONALD W. HERMAN
Ronald W. Herman, Controller (Principal Accounting Officer)

H. RODES HART
H. Rodes Hart, Director

EXHIBIT INDEX

Exhibit No.		Page Number or Incorporation by Reference to
3.1	Certificate of Incorporation of Murphy Oil Corporation as of September 25, 1986	Exhibit 3.1, Page Ex. 3.1-0 of Murphy's Annual Report on Form 10-K for the year ended December 31, 1991
3.2	Bylaws of Murphy Oil Corporation at February 3, 1993	Exhibit 3.3, Page 3.3-0 of Murphy's Annual Report on Form 10-K for the year ended December 31, 1992
3.3	Bylaws of Murphy Oil Corporation at February 2, 1994	Ex. 3.3-1
4	Instruments Defining the Rights of Security Holders. Murphy Oil Corporation is party to several long-term debt instruments, none of which authorizes securities that exceed 10 percent of the total assets of Murphy Oil Corporation and its subsidiaries on a consolidated basis. 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	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, Page 4.1-0 of Murphy's Annual Report on Form 10-K for the year ended December 31, 1989
10.1	1982 Management Incentive Plan	Exhibit 10.2, Page Ex. 10.2-0 of Murphy's Annual Report on Form 10-K for the year ended December 31, 1991
10.2	1987 Management Incentive Plan (adopted May 13, 1987, amended February 7, 1990 retroactive to February 3, 1988)	Exhibit 10.3, Page 10.3-0 of Murphy's Annual Report on Form 10-K for the year ended December 31, 1989
10.3	1992 Stock Incentive Plan	Exhibit 10.3, Page 10.3-0 of Murphy's Annual Report on Form 10-K for the year ended December 31, 1992.
13	1993 Annual Report to Security Holders	Ex. 13-0 - pages 4 through 62
	Appendix - Narrative of Graphic and Image Material	A-1
21	Subsidiaries of the Registrant	Ex. 21-1
23	Independent Auditors' Consent	Ex. 23-1
99.1	Undertakings	Ex. 99.1-1
99.2	Form 11-K, Annual Report for the fiscal year ended December 31, 1993 covering Combined Thrift Plans for Employees of Murphy Oil USA, Inc., and Deltic Farm & Timber Co., Inc.	To be filed as an amendment of this Annual Report on Form 10-K not later than 180 days after December 31, 1993.

Exhibits other than those listed above have been omitted since they either are not required or are not applicable.

BYLAWS

OF

MURPHY OIL CORPORATION

(A Delaware corporation)

ARTICLE I.

Offices.

Section 1. Offices. Murphy Oil Corporation (hereinafter called the Company) may have, in addition to its principal office in Delaware, a principal or other office or offices at such place or places, either within or without the State of Delaware, as the board of directors may from time to time determine or as shall be necessary or appropriate for the conduct of the business of the Company.

ARTICLE II.

Meetings of Stockholders.

Section 1. Place of Meetings. The annual meeting of the stockholders shall be held at the place therein determined by the board of directors and stated in the notice thereof, and other meetings of the stockholders may be held at such place or places, within or without the State of Delaware, as shall be fixed by the board of directors and stated in the notice thereof.

Section 2. Annual Meetings. The annual meeting of stockholders for the election of directors and the transaction of such other business as may come before the meeting shall be held in each year on the second Wednesday in May. If this date shall fall upon a legal holiday, the meeting shall be held on the next succeeding business day. At each annual meeting the stockholders entitled to vote shall elect a board of directors and they may transact such other corporate business as shall be stated in the notice of the meeting.

Section 3. Special Meetings. Special meetings of the stockholders for any purpose or purposes may be called by the Chairman of the Board or by order of the board of directors and shall be called by the Chairman of the Board or the Secretary upon the written request of stockholders holding of record at least a majority of the outstanding shares of stock of the Company entitled to vote at such meeting. Such written request shall state the purpose or purposes for which such meeting is to be called.

Section 4. Notice of Meetings. Except as otherwise expressly required by law, notice of each meeting of stockholders, whether annual or special, shall be given at least 10 days before the date on which the meeting is to be held to each stockholder of record entitled to vote thereat by delivering a notice thereof to him personally, or by mailing such notice in a postage prepaid envelope directed to him at his address as it appears on the books of the Company, unless he shall have filed with the Secretary of the Company a written request that notices intended for him be directed to another address, in which case such notice shall be directed to him at the address designated in such request. Notice of any meeting of stockholders shall not be required to be given to any stockholder who shall attend such meeting in person or by proxy; and if any stockholder shall in person or by attorney thereunto authorized, in writing or by telegraph, cable, radio or wireless and confirmed in writing, waive notice of any meeting of the stockholders, whether prior to or after such meeting, notice thereof need not be given to him. Notice of any adjourned meeting of the stockholders shall not be required to be given except where expressly required by law.

Section 5. Quorum. At each meeting of the stockholders the holders of record of a majority of the issued and outstanding stock of the Company entitled to vote at such meeting, present in person or by proxy, shall constitute a quorum for the transaction of business except where otherwise provided by law, the certificate of incorporation or these bylaws. In the absence of a quorum, any officer entitled to preside at or act as secretary of such meeting shall have the power to adjourn the meeting from time to time until a quorum shall be constituted. At any such adjourned meeting at which a quorum shall be present any business may be transacted which might have been transacted at the meeting as originally called.

Section 6. Voting. At every meeting of stockholders each holder of record of the issued and outstanding stock of the Company entitled to vote at such meeting shall be entitled to one vote in person or by proxy, but no proxy shall be voted after three years from its date unless the proxy provides for a longer period, and, except where the transfer books of the Company have been closed or a date has been fixed as the record date for the determination of stockholders entitled to vote, no share of stock shall be voted directly or indirectly. At all meetings of the stockholders, a quorum being present, all matters shall be decided by majority vote of those present in person or by proxy, except as otherwise required by the laws of the State of Delaware or the certificate of incorporation. The vote thereat on any question need not be by ballot unless required by the laws of the State of Delaware.

ARTICLE III.

Board of Directors.

Section 1. General Powers. The property, business and affairs of the Company shall be managed by the board of directors.

Section 2. Number and Term of Office. The number of directors shall be twelve, but may from time to time be increased or diminished to not less than three by amendment of these bylaws. Directors need not be stockholders. Each director shall hold office until the annual meeting of the stockholders next following his election and until his successor shall have been elected and shall qualify, or until his death, resignation or removal.

Section 3. Quorum and Manner of Acting. Unless otherwise provided by law the presence of six members of the board of directors shall be necessary to constitute a quorum for the transaction of business. In the absence of a quorum, a majority of the directors present may adjourn the meeting from time to time until a quorum shall be present. Notice of any adjourned meeting need not be given. At all meetings of directors, a quorum being present, all matters shall be decided by the affirmative vote of a majority of the directors present, except as otherwise required by the laws of the State of Delaware.

Section 4. Place of Meetings, etc. The board of directors may hold its meetings and keep the books and records of the Company at such place or places within or without the State of Delaware as the board may from time to time determine.

Section 5. Annual Meeting. Promptly after each annual meeting of stockholders for the election of directors and on the same day the board of directors shall meet for the purpose of organization, the election of officers and the transaction of other business. Notice of such meeting need not be given. Such meeting may be held at any other time or place as shall be specified in a notice given as hereinafter provided for special meetings of the board of directors or in a consent and waiver of notice thereof signed by all the directors.

Section 6. Regular Meetings. Regular meetings of the board of directors may be held at such time and place, within or without the State of Delaware, as shall from time to time be determined by the board of directors. After there has been such determination and notice thereof has been once given to each member of the board of directors, regular meetings may be held without further notice being given.

Section 7. Special Meetings; Notice. Special meetings of the board of directors shall be held whenever called by the Chairman of the Board or by a majority of the directors. Notice of each such meeting shall be mailed to each director, addressed to him at his residence or usual place of business, at least 10 days before the day on which the meeting is to be held, or shall be sent to him at such place by telegraph, cable, radio or wireless, or be delivered personally or by telephone, not later than the day before the day on which such meeting is to be held. Each such notice shall state the time and place of the meeting but need not state the purposes thereof. Notice of any meeting of the board of directors need not be given to any director, however, if waived by him in writing or by telegraph, cable, radio or wireless and confirmed in writing, whether before or after such meeting, or if he shall be present at such meeting. Any meeting of the board of directors shall be a legal meeting without any notice thereof having been given if all the directors then in office shall be present thereat.

Section 8. Resignation. Any director of the Company may resign at any time by giving written notice to the Chairman of the Board or the Secretary of the Company. The resignation of any director shall take effect upon receipt of notice thereof or at such later time as shall be specified in such notice; and, unless otherwise specified therein, the acceptance of such resignation shall not be necessary to make it effective.

Section 9. Removal. Any director may be removed at any time, either with or without cause, by the affirmative vote of the holders of record of a majority of the issued and outstanding class of stock of the Company entitled to vote for the election of such director, given at a special meeting of the stockholders called for that purpose. The vacancy in the board of directors caused by any such removal may be filled by the stockholders at such meeting.

Section 10. Vacancies. Any vacancy that shall occur in the board of directors by reason of death, resignation, disqualification or removal or any other cause whatever, unless filled as provided in Section 9 hereof, shall be filled by the majority (even if that be only a single director) of the remaining directors theretofore elected by the holders of the class of capital stock which elected the directors whose office shall have become vacant. If any new directorship is created by increase in the number of directors, a majority of the directors then in office may fill such new directorship. The term of office of any director so chosen to fill a vacancy or a new directorship shall terminate upon the election and qualification of directors at any meeting of stockholders called for the purpose of electing directors.

Section 11. Compensation of Directors. Directors may receive a fee, as fixed by the Chairman of the Board, for their services, together with expenses for attendance at regular or special meeting of the board. Members of committees of the board of directors may be allowed compensation for attending committee meetings. Nothing herein contained shall be construed to preclude any director from serving the Company or any subsidiary thereof in any other capacity and receiving compensation therefor.

ARTICLE IV.

Committees of the Board.

Section 1. Executive Committee. The board of directors shall elect from the directors an executive committee.

The board of directors shall fill vacancies in the executive committee by election from the directors.

The executive committee shall fix its own rules of procedure and shall meet where and as provided by such rules or by resolution of the board of directors, but in every case the presence of at least three members of the committee shall be necessary to constitute a quorum for the transaction of business.

In every case the affirmative vote of a majority of all of the members of the committee present at the meeting shall be necessary for the adoption of any resolution.

Section 2. Membership and Powers. The executive committee shall consist of five members in addition to the Chairman of the Board, who by virtue of his office shall be a member of the executive committee and chairman thereof. Unless otherwise ordered by the board of directors, each elected member of the executive committee shall continue to be a member thereof until the expiration of his term of office as a director.

The executive committee, subject to any limitations prescribed by the board of directors, shall have special charge of all financial accounting, legal and general administrative affairs of the Company. During the intervals between the meetings of the board of directors the executive committee shall have all the powers of the board in the management of the business and affairs of the Company, including the power to authorize the seal of the Company to be affixed to all papers which require it, except that said committee shall not have the power of the board (i) to fill vacancies in the board, (ii) to amend the bylaws, (iii) to adopt a plan of merger or consolidation, (iv) to recommend to the stockholders the sale, lease, exchange, mortgage, pledge or other disposition of all or substantially all of the property and assets of the Company otherwise than in the usual and regular course of its business, or (v) to recommend to the stockholders a voluntary dissolution of the Company or a revocation thereof.

Section 3. Other Committees. The board of directors may, by resolution or resolutions passed by a majority of the whole board, designate one or more other committees, each committee to consist of two or more of the directors of the Company, which, to the extent provided in said resolution or resolutions, shall have and may exercise the powers of the board of directors in the management of the business and affairs of the Company, and may have power to authorize the seal of the Company to be affixed to all papers which may require it. Such committee or committees shall have such name or names as may be determined from time to time by resolution adopted by the board of directors.

ARTICLE V.

Officers.

Section 1. Number. The principal officers of the Company shall be a Chairman of the Board, President, an Executive Vice President, one or more Vice Presidents, a Secretary, a Treasurer, and a Controller. No officers except the Chairman of the Board and President need be directors. One person may hold the offices and perform the duties of any two or more of said offices.

Section 2. Election and Term of Office. The principal officers of the Company shall be chosen annually by the board of directors at the annual meeting thereof. Each such officer shall hold office until his successor shall have been chosen and shall qualify, or until his death or until he shall resign or shall have been removed in the manner hereinafter provided.

Section 3. Subordinate Officers. In addition to the principal officers enumerated in Section 1 of this Article V, the Company may have one or more Assistant Vice Presidents, one or more Assistant Treasurers, one or more Assistant Secretaries and such other officers, agents and employees as the board of directors may deem necessary, each of whom shall hold office for such period, have such authority, and perform such duties as the board or the President may from time to time determine. The board of directors may delegate to any principal officer the power to appoint and to remove any such subordinate officers, agents or employees.

Section 4. Compensation of Principal Officers. The salaries of the principal officers shall be fixed from time to time either by the board of directors or by a committee of the board to which such power may be delegated. The salaries of any other officers shall be fixed by the President or by a committee or committees to which he may delegate such power.

Section 5. Removal. Any officer may be removed, either with or without cause, at any time, by resolution adopted by the board of directors at any regular meeting of the board or at any special meeting of the board called for the purpose at which a quorum is present.

Section 6. Vacancies. A vacancy in any office may be filled for the unexpired portion of the term in the manner prescribed in these bylaws for election or appointment to such office for such term.

Section 7. Chairman of the Board. The Chairman of the Board shall preside at all meetings of the stockholders and directors at which he may be present. He shall have such other authority and responsibility and perform such other duties as may be determined by the board of directors.

Section 8. President. The President shall be the chief executive officer of the Company and as such shall have general supervision and management of the affairs of the Company subject to the control of the board of directors. He may enter into any contract or execute any deeds, mortgages, bonds, contracts or other instruments in the name and on behalf of the Company except in cases in which the authority to enter into such contract or execute and deliver such instrument, as the case may be, shall be otherwise expressly delegated. In general he shall perform all duties incident to the office of President as herein defined and all such other duties as from time to time may be assigned to him by the board of directors. In the absence of the Chairman of the Board, the President shall preside at meetings of the stockholders and directors.

Section 9. Executive Vice President. The Executive Vice President shall in the absence or disability of the President perform the duties and exercise the powers of such office. He shall perform such other duties and have such other powers as the President or the board of directors may from time to time prescribe.

Section 10. Vice Presidents. The Vice Presidents, in order of their seniority unless otherwise determined by the board of directors, shall in the absence or disability of the President, and the Executive Vice President, perform the duties and exercise the powers of such offices. The Vice Presidents shall perform such other duties and have such other powers as the President or the board of directors may from time to time prescribe.

Section 11. Secretary. The Secretary shall attend all sessions of the board and all meetings of the stockholders, and record all votes and the minutes of all proceedings in a book to be kept for that purpose, and shall perform like duties for the committees of the board of directors when required. He shall give or cause to be given, notice of all meetings of the stockholders and of special meetings of the board of directors, and shall perform such other duties as may be prescribed by the board of directors, or the President, under whose supervision he shall be. He shall keep in safe custody the seal of the Company and, when authorized by the board of directors, affix the same to any instrument requiring it, and when so affixed it shall be attested by his signature or by the signature of the Treasurer or an Assistant Secretary.

Section 12. Treasurer. The Treasurer shall have custody of the corporate funds and securities and shall keep full and accurate accounts of receipts and disbursements in the books belonging to the Company, and shall deposit all moneys and other valuable effects in the name and to the credit of the Company in such depositories as may be designated from time to time by the Board of Directors.

He shall disburse the funds of the Company as may be ordered by the board, taking proper vouchers for such disbursements, and shall render to the President and board of directors at the regular meetings of the board, or whenever they may require it, an account of the financial condition of the Company.

If required by the board of directors, he shall give the Company a bond, in such sum and with such surety or sureties as shall be satisfactory to the board, for the faithful performance of the duties of his office, and for the restoration to the Company, in case of his death, resignation, retirement or removal from office, of all books, papers, vouchers, money and other property of whatever kind in his possession or under his control belonging to the Company.

Section 13. Controller. The Controller shall be in charge of the accounts of the Company and shall perform such duties as from time to time may be assigned to him by the President or by the board of directors.

ARTICLE VI.

Shares and Their Transfer.

Section 1. Certificates for Stock. Certificates for shares of capital stock of the Company shall be numbered, and shall be entered in the books of the Company, in the order in which they are issued.

Section 2. Regulations. The board of directors may make such rules and regulations as it may deem expedient, not inconsistent with the certificate of incorporation or these bylaws, concerning the issue, transfer and registration of certificates for shares of capital stock of the Company. It may appoint, or authorize any principal officer or officers to appoint, one or more transfer clerks or one or more transfer agents and one or more registrars, and may require all such certificates to bear the signature or signatures of any of them.

Section 3. Stock Certificate Signature. The certificates for shares of the respective classes of such stock shall be signed by, or in the name of the Company by, the Chairman of the Board, the President or any Vice President and the Treasurer or an Assistant Treasurer, or the Secretary or an Assistant Secretary, and where signed (a) by a transfer agent or an assistant transfer agent or (b) by a transfer clerk acting on behalf of the Company and a registrar, the signature of any such Chairman of the Board, President, Vice President, Treasurer, Assistant Treasurer, Secretary or Assistant Secretary may be facsimile. Each such certificate shall exhibit the name of the holder thereof and number of shares represented thereby and shall not be valid until countersigned by a transfer agent.

The board of directors may, if it so determines, direct that certificates for shares of any class or classes of capital stock of the Company be registered by a registrar, in which case such certificates will not be valid until so registered.

In case any officer of the Company who shall have signed, or whose facsimile signature shall have been used on, any certificate for shares of capital stock of the Company shall cease to be such officer, whether because of death, resignation or otherwise, before such certificate shall have been delivered by the Company, such certificate shall nevertheless be deemed to have been adopted by the Company and may be issued and delivered as though the person who signed such certificate or whose facsimile signature shall have been used thereon had not ceased to be such officer.

Section 4. Designations, Preferences, etc. on Certificates for Stock. Certificates for shares of capital stock of the Company shall state on the face or back thereof that the Company will furnish without charge to each stockholder who so requests (which request may be addressed to the Secretary of the Company or to a transfer agent) a statement of the designations, preferences and relative, participating, optional or other special rights of each class of stock or series thereof which the Company is authorized to issue and the qualifications, limitations or restrictions of such preferences and/or rights.

Section 5. Stock Ledger. A record shall be kept by the Secretary or by any other officer, employee or agent designated by the board of directors of the name of the person, firm, or corporation holding the stock represented by such certificates, the number of shares represented by such certificates, respectively, and the respective dates thereof, and in case of cancellation the respective dates of cancellation.

Section 6. Cancellation. Every certificate surrendered to the Company for exchange or transfer shall be canceled, and no new certificate or certificates shall be issued in exchange for any existing certificate until such existing certificate shall have been so canceled.

Section 7. Transfers of Stock. Transfers of shares of the capital stock of the Company shall be made only on the books of the Company by the registered holder thereof or by his attorney thereunto authorized on surrender of the certificate or certificates for such shares properly endorsed and the payment of all taxes thereon. The person in whose name shares of stock stand on the books of the Company shall be deemed the owner thereof for all purposes as regards the Company; provided, however, that whenever any transfer of shares shall be made for collateral security, and not absolutely, such fact, if known to the Secretary or the transfer agent making such transfer, shall be so expressed in the entry of transfer.

Section 8. Closing of Transfer Books. The board of directors may by resolution direct that the stock transfer books of the Company be closed for a period not exceeding 60 days preceding the date of any meeting of the stockholders, or the date for the payment of any dividend, or the date for the allotment of any rights, or the date when any change or conversion or exchange of capital stock of the company shall go into effect, or for a period not exceeding 60 days in connection with obtaining the consent of stockholders for any purpose. In lieu of such closing of the stock transfer books, the board may fix in advance a date, not exceeding 60 days preceding the date of any meeting of stockholders, or the date for the payment of any dividend, or the date for the allotment of rights, or the date when any change or conversion or exchange of capital stock shall go into effect or a date in connection with obtaining such consent, as a record date for the determination of the stockholders entitled to notice of, and to vote at, such meeting, and any adjournment thereof, or to receive payment of any such dividend, or to receive any such allotment of rights, or to exercise the rights in respect of any such change, conversion, or exchange of capital stock or to give such consent, as the case may be, notwithstanding any transfer of any stock on the books of the Company after any record date so fixed.

ARTICLE VII.

Miscellaneous Provisions.

Section 1. Corporate Seal. The board of directors shall provide a corporate seal which shall be in the form of a circle and shall bear the name of the Company and words and figures showing that it was incorporated in the State of Delaware in the year 1964. The Secretary shall be the custodian of the seal. The board of directors may authorize a duplicate seal to be kept and used by any other officer.

Section 2. Fiscal Year. The fiscal year of the Company shall be fixed by resolution of the board of directors.

Section 3. Voting of Stocks Owned by the Company. The board of directors may authorize any person in behalf of the Company to attend, vote and grant proxies to be used at any meeting of stockholders of any corporation in which the Company may hold stock.

Section 4. Dividends. Subject to the provisions of the certificate of incorporation, the board of directors may, out of funds legally available therefor, at any regular or special meeting declare dividends upon the capital stock of the Company as and when they deem expedient. Dividends may be paid in cash, in property, or in shares of capital stock of the Company, subject to the provisions of the certificate of incorporation. Before declaring any dividend there may be set apart out of any funds of the Company available for dividends such sum or sums as the directors from time to time in their discretion deem proper for working capital or as a reserve fund to meet contingencies or for equalizing dividends or for such other purposes as the directors shall deem conducive to the interests of the Company.

ARTICLE VIII.

Indemnification of Officers, Directors, Employees and Agents; Insurance.

Section 1. Indemnification.

(a) The Company may indemnify any person who was or is a party or is threatened to be made a party to any threatened, pending or completed action, suit or proceeding, whether civil, criminal, administrative or investigative (including an action by or in the right of the Company) by reason of the fact that he is or was a director, officer, employee or agent of the Company, or is or was serving at the request of the Company as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise, against expenses (including attorneys' fees) and, except for an action by or in the right of the Company, judgments, fines and amounts paid in settlement, actually and reasonably incurred by him in connection with such action, suit or proceeding, if he acted in good faith and in a manner he reasonably believed to be in or not opposed to the best interests of the Company, and, with respect to any criminal action or proceeding, had no reasonable cause to believe his conduct was unlawful. Except for an action by or in the right of the Company, the termination of any action, suit or proceeding by judgment, order, settlement, conviction, or upon a plea of nolo contendere or its equivalent, shall not, of itself, create a presumption that the person did not act in good faith and in a manner which he reasonably believed to be in or not opposed to the best interests of the Company, and, with respect to any criminal action or proceeding, had reasonable cause to believe that his conduct was unlawful. With respect to an action by or in the right of the Company, no indemnification shall be made in respect of any claim, issue or matter as to which such person shall have been adjudged to be liable for negligence or misconduct in the performance of his duty to the Company unless and only to the extent that the Delaware Court of Chancery or the court in which such action or suit was brought shall determine upon application that, despite the adjudication of liability but in view of all the circumstances of the case, such person is fairly and reasonably entitled to indemnity for such expenses which such court shall deem proper.

(b) To the extent that a director, officer, employee or agent of the Company has been successful on the merits or otherwise in defense of any action, suit or proceeding referred to in subsection (a) or in defense of any claim, issue or matter therein, he shall be indemnified against expenses (including attorneys' fees) actually and reasonably incurred by him in connection therewith.

(c) Any indemnification under subsection (a) (unless ordered by a court) shall be made by the Company only as authorized in the specific case upon a determination that indemnification of the director, officer, employee or agent is proper in the circumstances because he has met the applicable standard of conduct set forth in subsection (a). Such determination shall be made (i) by the board of directors by a majority vote of a quorum consisting of directors who were not parties to such action, suit or proceeding, or (ii) if such a quorum is not obtainable, or, even if obtainable a quorum of disinterested directors so directs, by independent legal counsel in a written opinion, or (iii) by the stockholders.

(d) Expenses incurred in defending a civil or criminal action, suit or proceeding may be paid by the Company in advance of the final disposition of such action, suit or proceeding as authorized by the board of directors in the manner provided in subsection (c) upon receipt of an undertaking by or on behalf of the director, officer, employee or agent to repay such amount unless it shall ultimately be determined that he is entitled to be indemnified by the Company as authorized in this section.

(e) The indemnification provided by this Article shall not be deemed exclusive of any other rights to which those seeking indemnification may be entitled under any agreement, vote of stockholders or disinterested directors or otherwise, both as to action in their official capacities and as to action in other capacities while holding such offices, and shall continue as to a person who has ceased to be a director, officer, employee or agent and shall inure to the benefit of the heirs, executors and administrators of such a person.

Section 2. Insurance. The Company may purchase and maintain insurance on behalf of any person who is or was a director, officer, employee or agent of the Company, or is or was serving at the request of the Company as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise against any liability asserted against him and incurred by him in any such capacity, or arising out of his status as such, whether or not the Company would have the power to indemnify him against such liability under the provisions of either the General Corporation Law of the State of Delaware or of these bylaws.

ARTICLE IX.

Amendments.

The bylaws of the Company may be altered, amended or repealed either by the affirmative vote of a majority of the stock issued and outstanding and entitled to vote in respect thereof and represented in person or by proxy at any annual or special meeting of the stockholders, or by the affirmative vote of a majority of the directors then in office given at any regular or special meeting of the board of directors. Bylaws, whether made or altered by the stockholders or by the board of directors, shall be subject to alteration or repeal by the stockholders as in this Article provided.

EXHIBIT 13

MURPHY OIL CORPORATION
1993 ANNUAL REPORT TO SECURITY HOLDERS

CONTENTS

BUSINESS ACTIVITIES

Murphy Oil Corporation is a natural resources company that operates through wholly owned subsidiaries in the United States and internationally to conduct the various business activities of the Murphy enterprise. As used in this report, the terms Murphy, we, our, its, and Company may refer to any one or more of the consolidated subsidiaries as well as to Murphy Oil Corporation.

PETROLEUM

Exploration and Production --

During 1993 Murphy was engaged in onshore and/or offshore exploration activities in nine countries. Crude oil and natural gas liquids are produced in the United States, Canada, the U.K. North Sea, Gabon, and Spain. Natural gas is produced in the United States, Canada, the U.K. North Sea, and Spain.

Refining, Marketing, and Transportation --

Murphy owns two refineries in the United States and shares ownership in a refinery in the United Kingdom. Petroleum products are sold at wholesale and retail in the United States, Western Europe, and Canada. Murphy also purchases, transports, and resells crude oil in Canada.

FARM, TIMBER, AND REAL ESTATE

Murphy is engaged in farming, timber and land management, and lumber manufacturing operations, primarily in Arkansas and North Louisiana, and in real estate development in western Little Rock, Arkansas.

COVER

In January 1992, the Company sold its contract drilling business for $372 million in cash and announced a program to reinvest the proceeds of that sale in its oil and gas business. The pictured production platform for "T" Block in the U.K. North Sea is symbolic of the results of that program, which has added substantial reserves to Murphy's books at a cost we believe to be attractive.

HIGHLIGHTS

FINANCIAL

(Thousands of dollars except per share data)	1993	1992	1991
FOR THE YEAR*			
Revenues	$ 1,671,137	1,685,415	1,690,086
Income (loss) from continuing operations	86,798	62,761	(9,607)
Income (loss) before extraordinary item and cumulative effect of changes in accounting principles	86,798	86,616	(11,157)
Net income (loss)	102,136	105,565	(11,157)
Cash dividends paid	55,945	53,821	47,234
Capital expenditures -- continuing operations	637,556	235,565	223,221
Net cash provided by continuing operations	362,973	284,159	213,635
Average Common shares outstanding	44,856,635	44,931,208	39,457,719
AT YEAR-END			
Working capital	$ 130,242	371,682	156,204
Total assets	2,168,859	1,936,514	2,174,626
Notes payable and other long-term obligations	21,709	24,929	193,152
Nonrecourse debt of a subsidiary	87,509	--	--
Stockholders' equity	1,222,350	1,200,088	1,200,819
PER SHARE OF COMMON STOCK*			
Income (loss) from continuing operations	$ 1.94	1.40	(.24)
Income (loss) before extraordinary item and cumulative effect of changes in accounting principles	1.94	1.93	(.28)
Net income (loss)	2.28	2.35	(.28)
Cash dividends paid	1.25	1.20	1.20
Stockholders' equity	27.28	26.76	26.71

*Includes unusual or infrequently occurring items that are detailed in Management's Discussion and Analysis, page 24.

OPERATING

	1993	1992	1991
Net crude oil and gas liquids produced -- barrels a day	34,311	30,820	33,495
United States	13,727	13,354	13,326
International	20,584	17,466	20,169
Net natural gas sold -- thousands of cubic feet a day	274,908	250,600	208,397
United States	215,471	188,068	151,157
International	59,437	62,532	57,240
Crude oil refined -- barrels a day	137,081	131,294	127,944
United States	109,090	107,049	101,975
United Kingdom	27,991	24,245	25,969
Petroleum products sold -- barrels a day	153,595	146,042	137,506
United States	120,842	114,379	104,011
Western Europe	32,519	31,491	33,366
Canada	234	172	129

[GRAPH: Working Capital and Long-Term Obligations at Year-End]

[GRAPH: Capital Expenditures]

[GRAPH: Market Price and Stockholders' Equity at Year-End]

LETTER FROM EXECUTIVE MANAGEMENT

DEAR SHAREHOLDER:

[Picture appears here]

Much of the industrialized world remained mired in recession during 1993. Growth in Gross Domestic Product dropped to 1.1 percent in the OECD as a whole, with Germany and Japan registering negative rates of 1.5 percent and .5 percent, respectively. In contrast, the U.S. grew three percent for the year, bolstered by a booming fourth quarter annualized rate of 7.5 percent. The most attractive financing costs in two decades finally "kicked in," and inflation remained moderate at about three percent in both the U.S. and OECD.

Predictably, world crude oil demand was weak, declining by .2 million barrels to 66.9 million barrels a day. The strengthening U.S. economy consumed 17.2 million barrels of oil a day, up .4 percent, and 20.5 trillion cubic feet of natural gas, up 4.8 percent. On the supply side, decline in former U.S.S.R. production was more than offset by increased output from other producers.

A weak world economy, with reduced and oversupplied oil demand, had a disastrous effect on prices. Average oil price for 1993 was about $2.25 a barrel lower than in 1992, and year-end 1993 was more than $5 below the previous year-end. In the U.S., higher total energy requirements had a positive impact on gas markets. Domestic prices exceeded 1992 by $.35 a thousand cubic feet. Downstream margins widened because of lower raw material cost and increased refinery utilization of 91.5 percent in the U.S.

Low interest rates accelerated housing starts from an annual rate of 1.2 million in January to 1.6 million in December. Higher demand and restricted cutting on federal lands propelled lumber prices to record highs by year-end.

FINANCIAL HIGHLIGHTS

Net income for 1993 was $102.1 million, $2.28 a share, compared to $105.6 million, $2.35 a share, in 1992. The overall numbers masked improved operating results, which totaled $76.4 million, $1.71 a share, up from $54.9 million, $1.22 a share, in 1992. Unusual items added $25.7 million to 1993 income, largely a result of the cumulative effect of accounting changes and settlement of income tax matters. All operating segments registered improvement over 1992. Lower oil prices were offset by higher oil and record gas volumes, lower exploration expenses, and improved North American gas prices. Downstream earnings, while not robust, improved considerably from 1992. Farm, timber, and real estate turned in record earnings on the combined strength of stumpage prices and sawmill margins.

Net cash provided by operating activities increased $79 million to $363 million, which when supplemented by a $237 million drawdown of cash, essentially covered capital expenditures and dividends to shareholders. Quarterly dividends were increased 8.33 percent to 32.5 cents a share. Oil and gas property acquisitions and attendant development costs of $342 million boosted total capital expenditures to $638 million. At year-end, long-term debt was $109.2 million, of which $87.5 million was nonrecourse to the Company; cash and marketable securities totaled $141.2 million.

OPERATING HIGHLIGHTS

Reserves -- On a per-equivalent-barrel basis, proved hydrocarbon reserves increased 101.1 million barrels, or 48 percent, to 311.3 million barrels. Major additions resulted from the acquisition of: (1) an 11.26-percent interest in Block 16/17, "T" Block, in the U.K. North Sea, 16.5 million barrels (reflecting only Tiffany and Toni fields); (2) a five-percent stake in the Syncrude project in northern Alberta, 83.8 million barrels (an additional 23 million barrels will be booked when the license is extended by seven years to 2025); and (3) the assumption of a 6.5-percent interest in the Hibernia oil field, offshore Newfoundland, 13.9 million barrels (approximately 19 million additional barrels will be added at Hibernia subsequent to start-up of production based on a consensus view of 525 million barrels of recoverable reserves).

Acquisitions -- Financial terms of the acquisitions of interests in Hibernia and "T" Block have been reported in earlier communications. The interest in Syncrude was purchased near year-end for $109 million. Similar to the Hibernia transaction, this acquisition involved nonrecourse debt, with the seller financing 60 percent of the consideration at a 6.25-percent fixed rate over five years. Cost of Syncrude reserves was $1.30 a barrel. Production from Syncrude averaged a record 183,500 barrels a day in 1993, with operating costs of $11.60 a barrel.

On a smaller scale, an additional 3.8-percent interest in the Ninian field was acquired effective January 1, 1994 through exercise of preemption rights. At five million barrels for $15 million, this was an unexpected bargain, a view shared by two other Ninian partners, who acquired the balance of the available interest.

Production -- Production in the second quarter should average in excess of 100,000 barrels of oil equivalent a day, including over 50,000 barrels of oil and 300 million cubic feet of natural gas. This increase results from start-up of 50 million cubic feet a day of new field developments and "first fruits" from acquisitions. The former is a combination of three Gulf of Mexico fields -- Viosca Knoll Blocks 203-204 (67%), South Timbalier Block 86 (87%), and Viosca Knoll Block 783, or Tahoe (30%). The latter is primarily production from "T" Block -- Tiffany field commenced in November and Toni field in December.

Exploration -- Although several discoveries were made in the Gulf of Mexico, onshore South Louisiana, and Canada, no major accumulations were found during 1993. Several "impact" wildcats, however, are drilling or will spud in the first half of 1994. Mobile Block 908 No. 3 (100%) is drilling, as is Mobile Block 863 No. 3 (11.5%). Pending results of these wells, other Norphlet prospects will likely spud in the second half of the year. The second well in Peru Block 62 was successfully farmed out and should commence drilling at no cost to the Company in the third quarter. A 20-percent interest is retained in the block.

Downstream -- Refinery crude throughputs increased 4.4 percent for the year to a record 137,000 barrels a day. Environmental considerations dominate investment decisions and operating results. Units designed to make mandated low-sulfur diesel came on stream on time and below budget at both Meraux and Superior. Milford Haven refinery (30%) is heavily engaged in front-end engineering on a similar unit. An additional sulfur plant will be added at Meraux this year, while a state-of-the-art waste-water treatment facility will be added at Superior.

Canadian pipelines enjoyed their fourth consecutive record throughput year, averaging 152,000 barrels a day. Milk River Pipeline (100%), one of Murphy's two U.S.-Canada border crossings, was the big gainer.

Farm and Timber -- This segment enjoyed its best year ever. An upgrade and expansion at the Ola sawmill came on stream just as margins improved. An expansion at Waldo, designed to increase volume and quality of finished lumber, is under way and will be completed at year-end. A record 147 residential lots were sold in Chenal during 1993.

OUTLOOK

No one expects continuation of economic growth in the U.S. at the extraordinary rate experienced in the fourth quarter. Nonetheless, recovery is under way. As a consequence, demand for oil and natural gas will increase at a time of shrinking oil supplies from the former U.S.S.R. and much-reduced surplus in the North American natural gas market. This is a recipe for growth.

Your Company is superbly positioned with strategic and financial balance provided by integrated operations and flexibility afforded by a strong financial condition. Even under draconian commodity price and margin assumptions, we expect cash flow from operations to carry the 1994 capital budget with only a modest draft of working capital. Borrowing capacity is reserved for opportunistic purchases and/or development of hydrocarbon reserves. The people and assets are in place for a good year. On the exploration front, important wildcats are planned, both in the U.S. and out, with renewed focus on obtaining frontier concessions. Crude oil production increases again when Ecuador comes on stream in the second quarter. Downstream, refineries will run heavier and higher sulfur crudes, and we are expanding our retail network, most notably in the U.K. Timber and real estate markets are booming, with no signs of letup.

Your Company's employees continue to merit confidence and support. They are our finest asset and are dedicated to increasing your wealth, while preserving the environment and maintaining safe work practices.

R. Madison Murphy
Executive Vice President
and Chief Financial and
Administrative Officer

Claiborne P. Deming
Executive Vice President
and Chief Operating Officer

Jack W. McNutt
President and
Chief Executive Officer

March 2, 1994

PETROLEUM

EXPLORATION AND
PRODUCTION

(Thousands of dollars)	1993	1992
Income contribution*	$ 36,861	35,935
United States	32,701	42,182
International	4,160	(6,247)
Total assets	1,223,118	789,494
United States	461,087	426,231
International	762,031	363,263
Capital expenditures	536,963	159,998
United States	92,912	72,883
International	444,051	87,115
Crude oil and liquids produced -- barrels a day	34,311	30,820
United States	13,727	13,354
International	20,584	17,466
Natural gas sold -- MCF a day	274,908	250,600
United States	215,471	188,068
International	59,437	62,532

* Before unusual or infrequently occurring items.

Earnings from the Company's exploration and production activities, excluding unusual or infrequently occurring items, totaled $36.9 million in 1993 compared to $35.9 million a year ago. The increase was due to higher crude oil production, record natural gas production, higher average sales prices for U.S. natural gas, and lower exploration expenses. These factors were partially offset by lower average crude oil prices. Production of crude oil and liquids totaled 34,311 barrels a day, up 11 percent, with all of our oil-producing areas experiencing increases. Natural gas production increased 10 percent to a record 274.9 million cubic feet a day, with the U.S. and Canada accounting for most of the increase. Crude oil prices in the U.S. and U.K. were each down 12 percent. Canadian light oil prices were down 10 percent, and heavy oil prices declined 11 percent. Sales prices for U.S. and Canadian natural gas were up 20 percent and 21 percent, respectively. On an energy equivalent basis, the Company's production was up 10 percent to 80,129 barrels a day.

The exploration and production function represents the Company's best opportunity for extraordinary growth. Murphy's exploration program includes a balance between low-cost, low-risk wells and high-risk frontier prospects that have potential for significant reserve additions.

Capital expenditures for exploration and production, including exploration expenditures charged to expense, totaled $537 million in 1993 compared to $160 million in 1992. In addition to participation in 166 wells, the current year included $259.7 million for acquisitions of proved properties. The more significant acquisitions are reviewed in the sections that follow. All but seven of 114 development wells were successful, and 28 of 52 exploratory wells were successful.

As shown in the schedules on pages 55 and 56, proved reserves of crude oil and liquids increased 106.4 million barrels, while natural gas reserves declined by 31.8 billion cubic feet. The acquisition of an 11.26-percent interest in "T" Block in the U.K. added an initial 16.5 million barrels of oil. Additional reserves will be added as development of this multi-field block takes place.

[GRAPH: Income Contribution -- Exploration and Production]

[GRAPH: Capital Expenditures -- Exploration and Production]

[MAP: Gulf of Mexico]

The five-percent interest acquired in a synthetic crude oil project in Canada (Syncrude) added 83.8 million barrels. During the year, the Company also booked 13.9 million of the 32.6 million barrels of oil attributable to its acquisition of a 6.5-percent interest in the Hibernia oil field, offshore Newfoundland. The Company expects to add the remaining 18.7 million barrels subsequent to start-up of production. The reserve amounts are based on the consensus of participants in the project that the field contains 525 million barrels of gross recoverable reserves. Other changes included a 2 million barrel reduction in Ecuador because of low oil prices at year-end, a 4.1 billion cubic feet upward revision in Spain due to well performance in the Gaviota field, and a 5.9 billion cubic feet addition in Spain due to the decision to develop the Albatros field. On an energy equivalent basis, Murphy's reserves totaled 311.3 million barrels at the end of 1993 compared to 210.2 million barrels at year-end 1992.

Details concerning the Company's exploration and production activities are presented in the sections that follow. The Company's working interest percentage is given, generally following the name of each field or block, and unless otherwise indicated, average daily production rates are net to the Company after deduction for royalty interests.

UNITED STATES

Average U.S. crude oil and liquids production totaled 13,727 barrels a day in 1993, up three percent from 1992, when production from certain fields was curtailed as a result of damage sustained from Hurricane Andrew in August. Natural gas production reached a record 215.5 million cubic feet a day in 1993, an increase of 15 percent when compared to 1992. The increase was due in part to commencement of production from Viosca Knoll Blocks 203 and 204 in October, and as with crude oil, 1992 production levels were adversely affected by Hurricane Andrew. Two other developments -- Viosca Knoll Block 783, a deep-water gas development project known as Tahoe, and South Timbalier Block 86, a sour gas discovery -- will be first quarter 1994 additions to production.

Exploration activities were conducted in the Gulf of Mexico; onshore Louisiana, Arkansas, and Texas; and offshore Alaska. In the Gulf of Mexico, the Company participated in 23 exploratory wells; 12 of which were successful. In addition, two deep tests of the Norphlet gas formation commenced in the fourth quarter. The Company also participated in 10 onshore exploratory wells; seven were successful. Offshore Alaska, we participated in two disappointing delineation wells. A total of 16 development wells were drilled in the U.S. during 1993; all were successful.

Gulf of Mexico -- Repair and replacement activities resulting from damages caused by Hurricane Andrew continued during 1993. The eye of the hurricane passed through several of the Company's major fields in the Ship Shoal, South Pelto, and South Timbalier areas. Four major production platforms were lost, and 55 satellite well structures were lost or severely damaged. Restoration of pre-hurricane production levels was completed in June 1993, and replacement of platforms and other facilities was completed by year-end. As a result of the storm, daily oil volumes were reduced by approximately 700 barrels in 1993 and 1,400 in 1992, and daily natural gas volumes were reduced by approximately 5 million cubic feet in 1993 and 13 million in 1992. The Company is adequately insured for costs of repair and replacement of property damaged, the effect on recoverable reserves was minor, and there was no environmental damage.

Ongoing interpretation of 3-D seismic data acquired in prior years led to drilling four successful wells during 1993 in the Ship Shoal Block 113 field (50-70%), one of the Company's oldest

[PICTURE APPEARS HERE]

[GRAPH: Crude Oil and NGL Production]

[GRAPH: Natural Gas Sales]

[PICTURE APPEARS HERE]

properties and our primary source of oil production in the U.S. Another 3-D location being drilled at year-end was successfully completed in early 1994. Four of the wells were oil and one was gas. To date, 31 of the 34 wells drilled from use of the 3-D data have been successful, and the results have more than offset normal production declines. Drilling is expected to continue through 1994 in this important field. Additional 3-D seismic data was acquired over the western portion of the field during the year, and early interpretation has already resulted in several leads. Oil production averaged 4,103 barrels a day in 1993 compared to 3,550 in 1992, and natural gas production averaged 14.5 million cubic feet a day compared to 10.6 million in 1992.

Drilling based on 3-D data in the South Pelto Block 20 field (50%), another older property, resulted in one successful oil well and one dry hole. In addition, two unsuccessful wells were drilled on the adjacent South Pelto Blocks 12 (85%) and 19 (50%). Oil production averaged 1,408 barrels a day in 1993 compared to 1,215 in 1992. Natural gas production averaged 7.8 million cubic feet a day in 1993 compared to 4.7 million a year ago.

The Ship Shoal Block 113A field (100%) was again one of the Company's major sources of natural gas production. Production associated with workover activity during 1993 offset normal decline, resulting essentially in a constant level of production. Although performance of this field continues to be excellent, it has been on stream since 1982, and deliverability is being affected. Production averaged 45.9 million cubic feet a day in 1993 compared to 39.2 million in 1992.

Oil production from the South Timbalier Block 86 field (86.9%) averaged 441 barrels a day in 1993, down from 695 in 1992. Development of a 1990 sour gas discovery is scheduled for completion in the first quarter of 1994, with an expected production rate of 5 million cubic feet a day.

In South Timbalier Block 63 (100%), oil production averaged 449 barrels a day in 1993 compared to 255 in 1992. Natural gas production averaged 9.8 million cubic feet a day compared to 5.3 million in 1992. An aggressive exploratory program is planned for this block in 1994 following interpretation of a 3-D seismic survey acquired during 1993.

A well in progress on Matagorda Island Block 589 (62.7%) at the end of 1992 was successfully completed and connected to facilities in Matagorda Island Block 604 (62.7%). The Block 604/589 area, another major source of gas production, currently has 13 wells on production, and two shallow gas wells drilled in prior years are available for hookup. Production in 1993 averaged 40.4 million cubic feet of natural gas a day compared to 36.9 million in 1992.

The Company has an interest in four natural gas fields offshore Alabama. Two wells in Mobile Blocks 952 and 953 (33.3%) and one in Mobile Block 955 (50%) flow into the facilities of the four-block Mobile Block 864 unit (13.1%). Production from these three fields commenced in March 1992 and averaged 8.7 million cubic feet a day in 1993 compared to 6.4 million in 1992. Production from the fourth field, Viosca Knoll Blocks 203 and 204 (66.7%), commenced in October 1993, when a gas pipeline was placed in service. The field includes production from eight wells, including one drilled horizontally for 1,200 feet. The horizontal completion allows the well to produce at a rate approximately three times that of a conventional completion. Production for the year averaged 7 million cubic feet of natural gas a day, with year-end production at 33 million.

During 1993, the Company participated in the development of Viosca Knoll Block 783 (30%), a 300-billion cubic feet natural gas discovery located in 1,500 feet of water. The first phase of development included a subsea completion of a previously drilled well, and installation of two four-inch pipelines and a control umbilical to connect the subsea wellhead to production facilities on a platform 12 miles to the north in 275 feet of water. The well came on stream in January 1994 at a rate of 10.4 million cubic feet of natural gas a day. The second phase, which anticipates full development of the block, will depend on evaluation of the reservoir and subsea production performance of the first phase.

A well drilled during the year on Mustang Island Block 789 (40%) resulted in a natural gas discovery. Field development will include installation of a 6.5-mile pipeline to existing production facilities in an adjacent block. First production is expected in the third quarter of 1994 at an estimated rate of 6.7 million cubic feet a day.

The Company holds a 33.3-percent interest in the Destin Dome Block 56 unit, which includes 11 leases covering 63,360 acres located approximately 40 miles south of Pensacola, Florida. A well tested in 1990 confirmed a 1988 natural gas discovery in the Norphlet formation, the source of production from several large natural gas fields in the Mobile Bay area, about 45 miles to the west. The two wells have proven an accumulation of natural gas at depths between 22,000 and 23,000 feet, and 64 billion cubic feet of natural gas attributable to these wells are included in the Company's reserves. A 3-D seismic survey over the 11-block unit has been acquired and interpreted. Other prospective Norphlet structures have been identified on several of the blocks. The operator of the unit continues to seek regulatory approval of a Plan of Development that addresses operational matters and environmental concerns.

The Company also holds interests in 10 leases in federal waters south of Mobile Bay, Alabama, the majority of which are prospective for significant Norphlet gas reserves below 20,000 feet. Wells on two high-potential Norphlet prospects, Mobile Blocks 908 (100%) and 863 (11.5%), were commenced in the fourth quarter of 1993. These wells should reach total depth in the second quarter of 1994. Interpretation of 3-D seismic data is ongoing, and wells to evaluate other Norphlet structures are planned.

The Company participated in 12 other exploratory wells in the Gulf of Mexico during 1993, five of which were successful. One of the successful wells resulted in a small oil discovery in Ship Shoal Block 101 (40%), which will be produced using facilities in an adjacent block. The remaining successful wells were in existing gas fields and included two in South Marsh Island Block 249 (15% and 16.7%), one in High Island Block A-370 (18.8%), and one in High Island Block A-332 (19.4%).

Murphy participated in the two 1993 federal lease sales held in the Gulf of Mexico and acquired 25- to 100-percent interests in eight blocks.

Onshore -- U.S. onshore exploration activity was principally in South Louisiana. Drilling activity in the East Riceville field (33.3%), located in Vermilion Parish, Louisiana, included a well drilled as an extension to the west of the field. The well did not encounter the sand found in the two producing wells and was abandoned. A field wildcat well (41.6%) on a separate fault block is planned for the second quarter of 1994. Daily production from the two producing wells in this field, which were placed on stream during 1992, averaged 9.6 million cubic feet of natural gas and 207 barrels of oil in 1993. Production in 1992 averaged 4.3 million cubic feet and 92 barrels of oil.

During 1993, the Company drilled the Cherry

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[MAP; CANADA]

Ridge Land Co. No. 1 (75%), located in Cameron Parish, Louisiana. Although the well was dry in its deep objective, it was completed as a gas/condensate well in a shallower sand. Production commenced in late February 1994 at 2.2 million cubic feet of natural gas a day.

Alaska -- During 1993, the Company participated in two disappointing wells in an effort to delineate the size of the 1992 Kuvlum (3.9%) discovery in the eastern Beaufort Sea, offshore Alaska. Current plans are to complete the processing of 700 lines of seismic data acquired over the prospect area and update our interpretation by integrating the well data and the new seismic information. Other activities in Alaska during 1993 included ongoing geophysical interpretation of the Sandpiper unit (57.6%), where two wells drilled in prior years found accumulations of hydrocarbons. We currently have interests in 47 leases offshore Alaska, mostly in the Beaufort Sea area.

Acreage Summary -- A summary of Murphy's net undeveloped acreage in the U.S. by area at year-end 1993 and 1992 follows.

(Thousands of acres)	1993	1992
Offshore - Lower 48		
Gulf of Mexico	351	344
Atlantic Coast	34	34
Offshore - Alaska		
Beaufort Sea	94	105
Chukchi Sea	--	41
Bering Sea	11	11
Onshore - Lower 48	36	55
	526	590

CANADA

Production of crude oil and liquids in Canada increased 25 percent in 1993 to 12,692 barrels a day, with light oil at 5,243 barrels a day and heavy oil at 7,449 barrels a day. Natural gas production was up 21 percent from a year ago to 36.8 million cubic feet a day. The 1993 production volumes for both oil and gas were at record levels.

The Company conducted an active drilling program in 1993, targeting high-margin development projects and high-reward exploratory plays. Development of light oil in 1993 included the drilling of eight successful horizontal wells at Bonanza, Parkman, Elswick, and Grand Forks (12.5-33.3%). In addition, eight successful vertical light oil development wells were drilled at Trout-Kidney and Grand Forks (20.5-33.2%). Light oil production also increased 501 barrels a day with the acquisition of a 32.5-percent interest in 11 Nisku oil wells in the Swalwell area of southern Alberta. The heavy oil program included 31 successful horizontal wells. In Saskatchewan, nine wells were drilled in Plover, Cactus Lake, Senlac, Tangleflags, and Eyehill (33-100%). Twenty-one wells were drilled in Alberta at South Bodo and Hayter (6.3-25%), and a 100-percent well was drilled at Lindbergh. A program at West Provost (25%) for 20 vertical wells and three wells at Tangleflags and Hayter (6.3-50%) completed the heavy oil program. This program resulted in a 39-percent increase in heavy oil production in 1993. However, because of the sharp drop in crude oil prices late in the year, some of the heavy oil production has been shut in, and development activities for heavy oil in 1994 will depend on the level of oil prices. Natural gas drilling activity consisted of eight successful wells in Umbach, Three Hills Creek, and Boundary Lake South (18-50%). In the Manir field (26.2%) in central Alberta, a conservation project to process gas that was being flared was successfully completed in March 1993. Another gas conservation project was initiated at Haynes to process the gas being flared from a 1992 light oil discovery. The project will also generate fees from processing third-party oil and gas in the area.

Murphy's exploration program in Canada during 1993 focused on high-potential prospects for gas in northeastern British Columbia and for light oil in central Alberta. The Company participated in 15 exploratory wells, eight of which were successful. Two were successful natural gas discoveries at Boundary Lake (25%) and Fort Pitt (100%). Three light oil step-out wells were completed in the Trout area (30.9-33.3%), and three exploratory horizontal heavy oil wells were successful in the Senlac and Cactus Lake areas (50-66.7%). In addition, a light oil prospect started at Loon Lake (66.7%) in December resulted in a discovery in January 1994. Further drilling is planned for 1994 to delineate the reserves. Two separate prospects offsetting this discovery are also scheduled for testing in 1994.

The Company continued to be selective in its land acquisition program. A total of 38,465 net acres were acquired, with our working interest averaging 72 percent. Natural gas prospects were acquired in northeastern British Columbia, including prospects on the high-potential Devonian Foothills trend. Light oil acreage continued to be enhanced with further acquisitions in Pembina, Cutbank, Haynes, Loon Lake, and Otter.

In December 1993, the Company acquired a five-percent interest in the Syncrude project, the world's largest oil sands mining and synthetic crude oil upgrading operation. This project is located on 96,645 acres leased from the province of Alberta in the Athabasca oil sands area near Fort McMurray. Synthetic crude oil is produced by a process that includes mining, extraction, and upgrading. The deposits are mined by large draglines and moved to an extraction plant, where the oil sands are mixed with hot water, steam, and caustic soda to produce a slurry, from which the oil floats as a froth. The froth is treated to remove water and solids and is fed into an upgrading process in the form of bitumen, which is then "cracked" into naphtha, light gas oil, and heavy gas oil streams. These streams are hydrotreated to remove sulfur and nitrogen impurities and mixed together to form synthetic crude oil. The current Syncrude license expires in the year 2018. Application has been made to the Alberta Energy Resources Conservation Board for an extension to 2025. Murphy's share of the reserves is estimated at 83.8 million barrels, and our share of production will be approximately 9,000 barrels a day of synthetic crude oil.

During 1993, the Company also acquired a 6.5-percent interest in the Hibernia oil field in the Grand Banks area, offshore Newfoundland. This field, discovered in 1979, is under

[MAP; HIBERNIA]
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development, with first production projected in 1997. The peak production level of 125,000 gross barrels of oil a day is expected to be reached in 1999. Gross recoverable reserves are estimated to be 525 million barrels. The central production facility for the Hibernia field is a Gravity Base Structure (GBS) -- the first GBS to be constructed to resist the impact of an iceberg. The skirting and base slab of the GBS are completed, and work is progressing on the walls and shafts. Construction of the main topside modules is well under way. Total pre-production costs to be incurred by the Company, net of government grants, are currently estimated at approximately $165 million, the majority of which will be funded through government-guaranteed nonrecourse loans.

UNITED KINGDOM

Production from the Ninian field (10%) averaged 5,780 barrels of oil a day in 1993, virtually the same as a year ago. Deployment of a flotel alongside the central platform, to provide accommodations for construction personnel, has allowed workover and drilling crews to accomplish an active and successful program to slow the rate of decline in production from this important field. Construction continued on the central and southern platforms in preparation for transporting third-party production from the Lyell and Strathspey fields to the Sullom Voe terminal. Lyell production commenced in March 1993, and Strathspey followed in December. Tariff income from third-party fields is expected to make an increasingly significant contribution to future Ninian cash flow. In November, an agreement was reached among the Ninian field owners to provide a commercial framework that will allow nearby marginal fields and prospects, containing a total of approximately 100 million barrels of oil, to use Ninian's processing facilities at predetermined tariff rates. Some of this oil is expected to be developed for production and transportation in 1994. A review of operating costs completed in 1992 led to a 15-percent cost reduction in 1993, with further reductions expected in 1994. Early in 1994, the Company exercised preemption rights to acquire an additional 3.82-percent interest in the Ninian field, increasing our interest to 13.82 percent.

Daily production from the Amethyst field (6.8%), which averaged 13.1 million cubic feet of natural gas and 99 barrels of condensate, was level with 1992 production. A 3-D seismic survey was acquired over the field and surrounding prospects during 1993, and interpretation of the data is in progress to finalize the locations for three development wells planned in 1994. The second redetermination of field equity interests is due to commence in March 1994.

Appraisal of the Mungo and Monan fields (12.7%) in Blocks 23/16a and 22/20 continued throughout the year, and interpretation of the 3-D seismic survey acquired in 1992 was completed. A well in the Mungo field, which underlies both blocks, was successfully tested at gross daily rates of 12,000 barrels of oil and 7 million cubic feet of natural gas. Due to the results of the short-term well test, an extended test was carried out during the summer of 1993 to determine well productivity and assist in estimating reserves. The test was conducted using a semi-submersible rig linked to a dynamically positioned storage tanker. A total of 777,500 barrels of oil were produced, the sale of which offset most of the cost of the test. The results of the test were encouraging, and gross recoverable reserves are expected to exceed 100 million barrels of oil equivalent. Feasibility studies for development of the two fields have shown that it is more attractive to jointly develop several fields in the area than pursue stand-alone development. The joint development project, known as the Eastern Trough Area Project (ETAP), will likely include a central processing platform for one of the larger fields, with other fields, including Mungo and Monan, produced via satellite platforms or subsea facilities. An engineering design agreement was signed by the ETAP participants in January 1994. Development approval is anticipated in 1995, at which time the Company will book its share of reserves. First production is expected in late

[PICTURE APPEARS HERE]

[MAP; NORTH SEA]

1998 or early 1999.

During 1993, the Company purchased an 11.26-percent interest in Block 16/17, also known as "T" Block. The block is located in the central North Sea approximately 150 miles northeast of Aberdeen, Scotland, and contains four separate oil and gas fields: Tiffany, Toni, Thelma, and Southeast Thelma. The first phase of development involved the Tiffany and Toni fields, using a conventional steel platform in the Tiffany field, with wells in the Toni field being connected to the platform from two subsea manifolds. Production commenced from Tiffany in November 1993 and from Toni in December. Peak production from Tiffany and Toni is expected to average 10,500 barrels a day. The 1993 average was 462 barrels a day. Initial production from Tiffany has been from four wells drilled in prior years. Three additional production wells and four water injection wells will be drilled from the platform in 1994 and 1995, with water injection commencing in mid-1994. The development of Toni involved two subsea well clusters, one for production and one for water injection. Four production wells and two injection wells have been drilled, and a third injection well will be drilled in 1994, if required. Control and monitoring of the subsea facilities is conducted from the Tiffany platform. Oil production from Tiffany and Toni flows to the Brae/Forties pipeline system; associated gas is transported to the Brae system for reinjection.

The Thelma and Southeast Thelma fields lie approximately five miles south of the Tiffany field, and development studies are under way, with first production from a subsea system anticipated in 1996. Development plans will be submitted to the U.K. government in 1994 for approval.

The Company has added 16.5 million barrels of oil to its proved reserves for the Tiffany and Toni fields. The associated gas has not been recognized in reserves because it is being sold at a price significantly lower than market to facilitate field development.

Exploration activity in the U.K. declined in 1993 from levels in recent years, partly as a result of tax changes announced in March by the U.K. government. At year-end, the Company was participating in two exploratory wells. One was designed to test a structure adjacent to a natural gas discovery on Block 43/22 (28%), which tested in 1992 at a gross daily rate of 12.5 million cubic feet, and the other was in Block 3/3 (19.4%) on the northeast flank of the Ninian field. Success at Block 43/22 may lead to commercial development. Success at Block 3/3 would lead to processing through the Ninian northern platform. Additional exploratory wells may be drilled to identify analogous structures on the east flank of the Ninian field. A 3-D seismic survey over Block 204/25a (17.7%) is planned for 1994. Evaluation of this block, located west of the Shetland Islands, will be of particular interest since a recent well drilled by others on Block 204/20 reportedly resulted in a significant oil discovery. The discovery is located approximately one mile north of our block. In the 14th Licensing Round, the Company was awarded Block 29/20b (30%), where an exploratory well is planned in 1994.

SPAIN

Production from the Gaviota field (18%) in the Bay of Biscay off the northern coast of Spain, averaged 9.6 million cubic feet of natural gas and 103 barrels of condensate a day in 1993. In 1992, daily production averaged 19.4 million cubic feet of gas and 239 barrels of condensate. Although gas and condensate rates were down substantially from

[MAP; ECUADOR]

1992 levels, well performance following the water breakthrough experienced last year has been better than predicted, and the original forecast for gas production in 1993 was exceeded by 36 percent. Cost-cutting initiatives led to a 30-percent reduction in operating costs, and modest reductions are expected in 1994. Evaluation of reservoir performance has led to an eight-percent increase in gross recoverable natural gas reserves, from 268 to 290 billion cubic feet, resulting in an addition to the Company's reserves in 1993 of 4.1 billion cubic feet.

Based on remaining reserves and current production rates, abandonment of the Gaviota field would likely occur in 1995 or 1996. However, plans have been formulated by the operator of the field to use the reservoir for strategic gas storage, and natural gas owned by third parties will be injected into the reservoir during the summer months and extracted for distribution during the winter months. The current production facilities will require modifications, and three gas-injection wells will be drilled. Capital expenditures, operating costs, and a profit element will be recovered by means of tariffs. The operator has agreed on the project terms with ENAGAS, the Spanish gas distribution company, and as a co-owner of the Gaviota field, the Company is negotiating final commercial details for participation in the project. Under the agreement, production from the Gaviota field will cease at the end of March 1994, and ENAGAS will purchase all remaining reserves. The target date for first gas injection is August 1994.

Conversion of the Gaviota field to long-term use as a gas storage facility now permits development of the Albatros field (18%), located 11 miles west of Gaviota. This field, discovered several years ago, contains gross recoverable reserves of up to 50 billion cubic feet of natural gas and will be developed in 1994 using a single subsea well connected to the Gaviota platform. First gas production is expected in mid-1995. Plans for 1994 also include a step-out well to the west of the discovery well.

GABON

Virtually all of the production in Gabon is from the Breme field (45%). Production quantities reported under Production Sharing Contracts include entitlements for cost recovery and a share of the profit oil after cost recovery. Entitlements for 1993 averaged 1,447 barrels of oil a day compared to 1,111 in 1992.

ECUADOR

The Company has a 20-percent interest in risk-service contracts (similar to production-sharing contracts) covering Block 16 and the Tivacuno field, an oil discovery north of Block 16. Block 16 is a 494,000-acre license located east of the Andes mountains in the Oriente Basin. This block is adjacent to and on trend with major producing fields to the west and north and has multiple structures similar to those producing in the area. In addition, the Capiron field, also located to the north, has been unitized as part of Block 16. The development plan, which is based on gross reserves in excess of 200 million barrels of crude oil, provides for construction of two central production facilities, an extensive drilling program, and construction of a pipeline to connect with the existing pipeline infrastructure. In 1993, development activity involving the northern fields -- Capiron, Tivacuno, and the Bogi field on Block 16 -- included drilling and/or completion of six wells, with two wells in progress at year-end. In addition, 147 miles of pipeline were installed, and 47 miles of road were constructed. Completion of pipelines, roads, and the northern production facility is anticipated late in the first quarter of 1994, allowing for first production from the Capiron, Tivacuno, and Bogi fields. During 1994, road and pipeline construction will continue to the Amo field in the southern part of Block 16, and development drilling will be concentrated at Capiron and Amo. As a result of the fall in oil prices, construction of the southern

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production facility has been deferred until 1995-96. Prior to completion of the southern facility, the Amo field will be produced through the northern facility and is expected to be on stream in the fourth quarter of 1994.

The Block 16 owners submitted the sole bid in 1990 for a license to Block 22, directly east of Block 16; however, an exploratory work program remains to be negotiated.

OTHER

During 1993, Murphy entered into a farmin agreement covering an onshore block in the Maranon Basin of Peru, under which the Company earned a 40-percent interest in a production-sharing contract covering 2.4 million acres. A well drilled during the year on the Pucacuro prospect was dry. A second well is planned in mid-1994 on a closure known as the Arabella prospect. Subsequent to year-end, the Company farmed out half of its interest in this block. Technical evaluations of the other areas in Peru are ongoing.

A study group was formed with two other companies to evaluate acreage available in the Irish Frontier Licensing Round. As a result, in December 1993 the group applied for a large area west of Ireland. In China, preparations are under way to participate in the second onshore bid round scheduled for the second quarter of 1994.

In Somalia, Murphy has a 10-percent interest in four million acres encompassing onshore Block 35 and offshore Block M10A. The Company also has a 100-percent interest in the 6.7-million acre Kharan concession in Pakistan. Both of these concessions remained in a force majeure status during 1993; however, discussions were held with the Pakistani government during the year on lifting the force majeure in order to commence exploration activity.

REFINING, MARKETING, AND TRANSPORTATION

(Thousands of dollars)	1993	1992
Income contribution*...........	$ 31,541	8,005
United States................	11,188	(6,011)
International................	20,353	14,016
Total assets....................	589,202	575,061
United States.................	378,405	346,151
International.................	210,797	228,910
Capital expenditures............	86,885	68,073
United States.................	71,363	44,198
International.................	15,522	23,875
Crude oil processed--barrels a day.........................	137,081	131,294
United States.................	109,090	107,049
International.................	27,991	24,245
Products sold--barrels a day....	153,595	146,042
United States.................	120,842	114,379
International.................	32,753	31,663
Average gross margin on products sold--dollars a barrel		
United States.................	$ .82	.48
Western Europe................	3.08	2.67

*Before unusual or infrequently occurring items.

Earnings from the Company's refining, marketing, and transportation operations, excluding unusual or infrequently occurring items, totaled $31.5 million in 1993 compared to $8 million in 1992. Our U.S. operations earned $11.2 million compared to a loss of $6 million a year ago. Earnings from operations in Western Europe totaled $11.7 million, up from $4.6 million in 1992. The earnings contribution from purchasing, transporting, and reselling crude oil in Canada totaled $8.6 million in 1993 compared to $9.4 million a year ago. The Company's composite average gross margin on product sales in the U.S. was up 71 percent. Regionally, margins in the Southeast continued to be under pressure, while in the upper-Midwest, margins increased due primarily to an improved asphalt season. Margins in Western Europe were up 15 percent from the depressed levels of 1992. Sales volumes increased six percent in the U.S. to 120,842 barrels a day and three percent in Western Europe to 32,519 barrels. The decline in Canadian earnings was due primarily to lower crude oil trading volumes.

Maintaining modern, efficient, and competitive refining and distribution systems is a key element of Murphy's strategy for its downstream business. This strategy has required investment of substantial sums in recent years, and additional projects are under way or planned. Capital expenditures for 1993 totaled $86.9 million compared to $68.1 million in 1992. The 1993 expenditures included nearly $38 million for distillate desulfurization projects. A significant portion of capital expenditures in our downstream operations relates to the responsibility to operate in an environmentally safe manner. Capital expenditures addressing environmental concerns, including the distillate desulfurization expenditures, were $54 million in 1993.

[GRAPH: Income Contribution--Refining, Marketing, and Transportation]
[GRAPH: Capital Expenditures--Refining, Marketing, and Transportation]
[GRAPH: Refined Products Sold]

UNITED STATES

The Company is engaged in downstream activities in two separate regions of the U.S. A 100,000-barrel-a-day refinery in Meraux, Louisiana, produces refined petroleum products for distribution over an eleven-state area in the southeastern part of the U.S. that is generally referred to as the Gulf Coast market. A five-state area in the upper-Midwest is served by a 35,000-barrel-a-day refinery in Superior, Wisconsin.

The Gulf Coast market is highly competitive, and margins in the area have been depressed in recent years by excess refinery capacity and a weak U.S. economy. A successful refiner in this market must seek advantage through operating efficiencies and a continuing effort to reduce costs. To achieve those goals, the Company has under way a capital investment program that commenced with expansion of crude oil processing capacity to the current 100,000-barrel-a-day level in 1991. During 1993, construction of a distillate desulfurizer was completed. This important project, finished ahead of schedule and below budget, enables the refinery to produce low-sulfur diesel fuel as mandated by the 1990 Clean Air Act. Low-sulfur diesel accounted for 79 percent of the refinery's diesel production for the final four months of 1993, allowing the Company to capitalize on the initial high spreads between low-sulfur and conventional diesel fuel. In addition to producing a new value-added product, the distillate desulfurizer has also allowed us to include additional quantities of less expensive, heavier crudes in the array of crudes we can process. The unit also served as the foundation to further reduce crude costs by increasing

[MAP: United States]
[GRAPH: Meraux Refinery Crude Charge]
[GRAPH: Meraux Refinery Yields]

sour crude processing capacity, and a project is scheduled for completion in 1994 that will move the Meraux refinery to the next level by permitting a 50-percent light sour crude slate. Completion of the sour crude project will finish the capital investment program designed to improve the competitiveness of the Meraux refinery. Additional capital investments planned at Meraux include a low-cost project to produce reformulated gasoline by January 1995.

Crude oil processed at the Meraux refinery during 1993 averaged 78,732 barrels a day, down from 80,842 in 1992. Inputs of other feedstocks averaged 6,398 barrels a day compared to 5,477 a year ago. Market-driven curtailments and downtime on the No. 2 cat cracker combined to reduce inputs in the current year. Crude oil requirements at Meraux are met through a combination of foreign-source crudes, our own production of U.S. crudes, and third-party purchases at posted prices. The flexibility provided by this mix, along with the ongoing capital investment program, are providing opportunities to minimize overall crude costs. This combination has resulted in reducing the light sweet crude component of our crude runs during the past two years from 69 percent in 1991 to 45 percent in 1993. The light sweet crude has been replaced with less expensive heavy and sour crudes. Average crude gravity declined from 34.2 degrees in 1991 to 32.8 degrees in 1993, and despite the reduction in crude quality, residual yields declined from 12.8 percent to 11.7 percent during the two-year period. Light sour crude runs have increased from two percent in 1991 to 26 percent in 1993.

Crude runs at the Company's Superior refinery were 30,358 barrels a day, an increase of 16 percent over 1992. Asphalt sales were up 25 percent over 1992. A key component of the increase in asphalt sales was the successful operation of the Company's new Crookston, Minnesota, asphalt terminal. New markets reached by this terminal were major contributors to the successful year. The blend of crude oil processed at the refinery continued to complement Murphy's Canadian production of heavy oil. The volume of heavy asphaltic crude processed in 1993 increased by 27 percent over 1992 runs. Additional synergies will be achieved in 1994 by processing the Company's share of production from the Canadian synthetic crude oil project.

A revamp of an existing hydrotreater was completed at Superior in August 1993, enabling low-sulfur diesel to be introduced ahead of schedule and allowing the refinery to capitalize on initial demand and attendant high margins during the third quarter.

The Company's distribution system in the Southeast consists of 29 terminals, 21 of which are either wholly or jointly owned, that are supplied from the Meraux refinery by barge or pipeline. The refinery's strategic location on the Mississippi River provides flexibility to maximize margins through product trading and by shifting between terminal and cargo sales as market conditions dictate. Total product sales in the Southeast totaled 91,618 barrels a day, an increase of two percent. In the upper-Midwest, 10 terminals serving markets in North Dakota, Minnesota, and western Wisconsin are supplied from the Superior refinery by pipeline. Markets in southeastern Wisconsin and western Michigan are served from five terminals supplied by pipeline from Chicago, where products are received from others in exchange for deliveries at Superior. Asphalt terminals in Crookston and Rhinelander, Wisconsin, are supplied by truck. Total product sales in the upper-Midwest increased by 18 percent to 29,224 barrels a day.

Sixty-nine percent of Murphy's U.S. gasoline sales were at terminals in 1993, 39 percent of which were sales to SPUR branded outlets. The remaining 31 percent of gasoline sales were in the bulk cargo market. Seventy percent of diesel and home heating oil sales were at terminals, with the balance going to the cargo market. Twenty-three percent of the terminal sales were to SPUR outlets. We sold 14 percent of our kerosine at terminals, and the remaining 86 percent

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was sold in the bulk cargo market.

During 1993, the Company's U.S. marketing efforts included a program of consolidation that emphasized retaining quality stations in our primary market areas. Emphasis is being placed on providing attractive outlets for our products, with particular attention directed to expansion of convenience stores. At December 31, 1993, there were 606 SPUR branded stations in 14 states.

UNITED KINGDOM

During 1993, Murphy processed an average of 27,991 barrels of crude oil a day at our jointly owned refinery in Milford Haven, Wales, compared with 24,245 in 1992. As a result of higher crude runs in 1993, processing of intermediate feedstocks was reduced from 7,102 barrels a day in 1992 to 3,638 barrels in the current year. The triennial maintenance turnaround occurred in the second quarter, at which time modifications were made to further increase the capacity of the alkylation unit. Turnaround work on the crude unit allowed an increase in crude runs. Modifications were also undertaken to improve the quality of feedstocks to the naphtha isomerization unit. This unit, commissioned in late 1992, has increased the ability of the refinery to produce higher octane unleaded gasolines. To further accommodate the increasing demand for unleaded gasolines, along with reducing volatility and benzene levels, facilities to handle methyl tertiary butyl ether are under construction and should be available for use early in the second quarter of 1994.

Concerns over environmental emissions within the European Union continue to influence investment decisions. Regulations to impose further reductions in the sulfur content of both diesel oil and gasoline are scheduled to take effect over the next few years. An engineering design study has been completed for construction of a high-pressure distillate

[MAP: United Kingdom]

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hydrotreater to start operating in 1996. A project is also under review to modify the cat cracker to meet lower sulfur limits in gasoline while maintaining the capability to process medium-sulfur crudes. Other projects under review include an on-line gasoline blending system that would provide more consistent product quality and improve production flexibility. Detailed planning for a butane isomerization unit has also commenced. This unit will enable the refinery to produce higher-value feedstock for the alkylation unit from lower-value butane, which will no longer be blended into gasoline due to restrictions on vapor emissions.

Milford Haven is supplied by North Sea crude oil purchased in the spot market or, alternatively, with proprietary Brent or Forties Blend. Exposure to price volatility is reduced to the extent possible by pricing each spot purchase over the same period of time that crude is processed and products are sold. Additional feedstocks for the cat cracker and alkylation units are purchased in the spot market when required. Transportation to the refinery is provided by tankers chartered at spot rates.

Demand for road fuels in the U.K. remained weak in 1993 -- diesel sales showed a modest increase, but gasoline sales were down for the second consecutive year. However, retail sales through the Company's branded outlets increased by five percent, from 7,717 barrels a day in 1992 to 8,119 in 1993, despite increased competition from supermarket operators. Gross margin from branded retail sales was up 8.6 percent. The Company opened a new marketing area in southwest Wales during 1993, and 12 stations were in operation at year-end. Company-owned stations totaled 134 at the end of 1993, an increase of nine; dealer stations were up 28 to 294. Wholesale product sales in the U.K. were down from 1,135 barrels a day in 1992 to 520 in 1993.

The remainder of the Company's Milford Haven production is sold into the bulk cargo markets; these sales totaled 23,880 barrels a day in 1993, up five percent over 1992. Demand for kerosine and diesel increased over 1992, but gasoline sales were down, accounting for 25 percent of bulk sales in 1993 compared to 28 percent a year ago.

CANADA

Murphy conducts an active crude oil trading operation in Canada and has interests in four crude oil pipeline systems, including two of the six systems that cross the border from Canada into the U.S. Anciliary activities include crude oil and LPG trucking operations and sale of refined products in Thunder Bay, Ontario. Margins on sales of purchased crude were essentially unchanged from a year ago, but sharply lower crude oil prices adversely affected trading volumes. While pipeline throughputs increased 29 percent in 1993 to 151,722 barrels a day, operating costs also increased and partially offset the volumetric gains.

The Manito pipeline system (52.5%) transported 44,844 barrels a day of heavy oil blend in 1993, basically unchanged from a year ago. Throughput volumes on the Bodo/Cactus Lake system (26.3%/13.1%) increased 48 percent to 31,195 barrels a day on increased crude production in areas supplying the system. Throughput volume in the Milk River system (100%), one of the systems crossing the U.S. border, was up 53 percent to 47,152 barrels a day, partially due to a new light oil stream. The other cross-border pipeline is the Wascana system (100%), which had a throughput of 28,531 barrels a day, an improvement of 43 percent. The increase was partially due to a higher level of demand for medium-sour crude in the Rocky Mountain area of the U.S. (PADD IV) that is expected to continue in 1994. Crude oil hauled by our trucking operations was down in 1993, but sales of refined products at Thunder Bay increased 36 percent. Thunder Bay is supplied from our Superior refinery, and the Company operates seven branded retail outlets and one branded wholesale outlet in the area.

[MAP: Canada--Pipelines]
[GRAPH: Canadian Pipeline Throughputs]

FARM, TIMBER, AND REAL ESTATE

(Thousands of dollars)	1993	1992
Income contribution............	$ 13,154	8,362
Total assets....................	150,261	141,784
Capital expenditures............	9,674	6,017
Lumber sales--thousand board feet	115,136	105,619
Residential lots sold...........	147	120
Land owned--acres		
Farm..........................	36,000	36,000
Timber........................	341,000	342,000
Real Estate...................	10,000	10,000

The Company's farm, timber, and real estate operations are conducted through its wholly owned subsidiary, Deltic Farm & Timber Co., Inc. Deltic reported record earnings in 1993 of $13.1 million, up 56 percent from the $8.4 million earned in 1992. Substantial improvements were recorded by timber and real estate operations, while operating results on the farms were off sharply compared to 1992.

Farming operations reported a loss of $.1 million in 1993 compared to earnings of $1.2 million a year ago. Cold, wet, springtime conditions were followed by heavy rainfall during early summer and prolonged drought during late summer. These weather patterns reduced yields on all crops. Corn yields of 70 bushels per acre in 1993 were 48 bushels per acre lower than in 1992, a decrease of 41 percent. Soybean yields declined 38 percent to 24 bushels per acre in 1993 compared to 39 bushels per acre in 1992. Cotton yields of 661 pounds per acre in 1993 represented a 170-pound per acre reduction from 1992, down 20 percent. Although adverse weather conditions resulted in disappointing yields during 1993, Deltic is confident that no-till and minimum-till cultivation practices will enhance the profitability of the farms and prove to be ecologically beneficial. Future efforts will continue to emphasize improved cultivation methods, more effective cost-control practices, and research for heavy-soil crop alternatives.

The interest-rate-induced pickup in U.S. housing starts and the associated effect on lumber demand pushed Deltic's earnings from timber operations to an all-time high of $11.3 million, up 95 percent compared to 1992 earnings of $5.8 million. Finished lumber production from Deltic's two sawmills reached record levels and totaled 112.4 million board feet, an increase of 11 percent from the 101.2 million produced in 1992. The average sales price for finished lumber also set a record, rising to $335 per thousand board feet in 1993 compared to $259 in 1992, an increase of 29 percent. Average pretax mill margins were $82 per thousand board feet compared to $34 a year ago. The Ola, Arkansas, mill upgrade was completed, and production using the new equipment started in April 1993. The upgrade allowed the Ola mill to produce a more valuable mix of finished lumber and increases the yield per log by over 20 percent. The Waldo, Arkansas, mill increased production of finished lumber by 5.8 million board feet in 1993 to 71.1 million, due in part to the new trimmer-optimizer installed in 1992. An additional $8.3-million expansion planned for the Waldo mill in 1994, will provide the product flexibility needed to further maximize the value from each log processed.

[GRAPH: Income Contribution -- Farm, Timber, and Real Estate]
[GRAPH: Capital Expenditures -- Farm, Timber, and Real Estate]
[GRAPH: Sales of Finished Lumber]

[PICTURE APPEARS HERE]

Rising lumber prices and harvest curtailments on federal lands continue to enhance the value of Deltic's timber. Sales of pine sawtimber increased to 37.6 million board feet in 1993 compared to 30.2 million in 1992. Average sales prices increased 13 percent to $310 per thousand board feet. Hardwood sawtimber sales were 2.8 million board feet in 1993, unchanged from a year ago. Pine pulpwood sales totaled 12,536 cords in 1993 compared to 8,767 in 1992.

Real estate operations contributed $2.4 million to earnings in 1993 compared to $1.8 million in 1992, an increase of 33 percent. Lower long-term mortgage rates sparked an increase in residential lot sales at Chenal Valley, Deltic's 4,300-acre planned community in Little Rock, Arkansas. This development is firmly established as the location of preference in the Little Rock area and continued to increase its residential market share with a total of 147 lot sales in 1993 compared to 120 in 1992. Chenal's newest residential areas -- Avignon Court, Aberdeen Court, Bayonne Place, and LaMarche Place -- accounted for sales of 126 lots in 1993. Aberdeen Court and Bayonne Place were the first two areas to be opened on the north slope of Chenal Valley. Plans are under way to continue development in this area in 1994. Construction of the first model home in The Oaks will commence in early 1994 as part of Deltic's plans to capture a greater portion of the residential real estate dollar. Lot buyers will be able to select from a set of eight floor plans under a turnkey arrangement that will provide a finished home. Deltic also believes that the number of homes in Chenal has now reached a level that will support commercial development, and plans are under way to enter that market in 1994.

[PICTURE APPEARS HERE]
[PICTURE APPEARS HERE]

FINANCIAL REVIEW

SELECTED FINANCIAL INFORMATION

(Thousands of dollars except per share data)	1993	1992	1991	1990	1989
RESULTS OF OPERATIONS FOR THE YEAR(1)					
Sales and other operating revenues	$1,636,668	1,631,441	1,600,935	1,867,381	1,551,557
Net cash provided by continuing operations	362,973	284,159	213,635	284,431	303,673
Income (loss) from continuing operations	86,798	62,761	(9,607)	113,524	78,783
Income (loss) before extraordinary item and cumulative effect of changes in accounting principles	86,798	86,616	(11,157)	98,746	46,551
Net income (loss)	102,136	105,565	(11,157)	114,009	46,551
Per Common share					
Income (loss) from continuing operations	1.94	1.40	(.24)	3.34	2.32
Income (loss) before extraordinary item and cumulative effect of changes in accounting principles	1.94	1.93	(.28)	2.91	1.37
Net income (loss)	2.28	2.35	(.28)	3.36	1.37
Dividends	1.25	1.20	1.20	1.00	1.00
Percentage return on					
Average stockholders' equity	8.4	8.8	(1.1)	13.8	6.2
Average borrowed and invested capital	8.4	9.7	1.5	13.2	6.8
Average total assets	5.0	5.3	(.6)	6.5	2.2
CAPITAL EXPENDITURES FOR THE YEAR					
Exploration and production(2)	$ 536,963	159,998	155,017	146,679	135,366
Refining, marketing, and transportation	86,885	68,073	63,143	59,056	28,205
Farm, timber, and real estate	9,674	6,017	2,858	10,375	11,201
Corporate and other	4,034	1,477	2,203	4,039	4,886
	$ 637,556	235,565	223,221	220,149	179,658
FINANCIAL CONDITION AT YEAR-END					
Current ratio	1.32	1.87	1.30	1.17	1.30
Working capital	$ 130,242	371,682	156,204	106,518	144,846
Net property	1,549,250	1,073,179	1,128,641	1,040,825	1,075,585
Total assets	2,168,859	1,936,514	2,174,626	2,126,719	2,064,042
Long-term obligations(3)	109,218	24,929	193,152	207,867	330,339
Minority interest	--	--	--	180,516	158,803
Stockholders' equity	1,222,350	1,200,088	1,200,819	873,163	769,578
Per share	27.28	26.76	26.71	25.76	22.71
Long-term obligations(3) -- percent of capital employed	8.2	2.0	13.9	16.5	26.2

(1) Includes effects on income of unusual or infrequently occurring items in 1993, 1992, and 1991 that are detailed in Management's Discussion and Analysis, page 24. Also, unusual or infrequently occurring items in 1990 and 1989 resulted in an increase (decrease) to net income of $17,923 and $(32,232), $.53 a share and $(.95) a share, respectively.

(2) Includes amounts expensed and cost of assets acquired by assuming directly related liabilities.

(3) Includes nonrecourse debt in 1993 of $87,509, which is 6.6 percent of capital employed.

[GRAPH: Income Excluding Unusual Items]

[GRAPH: Cash Provided by Continuing Operations]

[GRAPH: Stockholders' Equity at Year-End]

MANAGEMENT'S DISCUSSION AND ANALYSIS

RESULTS OF OPERATIONS

Consolidated net income for 1993 was $102.1 million, $2.28 a share, compared to $105.6 million, $2.35 a share, in 1992. In 1991, the Company reported a loss of $11.2 million, $.28 a share, on fewer average Common shares outstanding. As reviewed in Note D to the consolidated financial statements, the Company sold its contract drilling business effective January 1, 1992. This activity has been accounted for as discontinued operations, and net income for 1992 included a gain of $23.9 million, $.53 a share, from disposal of the contract drilling business. Consolidated results of operations in 1991 included a loss from discontinued contract drilling operations of $1.6 million, $.04 a share. Results of operations for the three years ended December 31, 1993 also included other unusual or infrequently occurring items that resulted in a net gain of $25.7 million, $.57 a share, in 1993; a net gain of $26.8 million, $.60 a share, in 1992; and a net charge of $67.3 million, $1.71 a share, in 1991. The 1993 net gain included $15.3 million, $.34 a share, from adoption of new accounting standards.

Income from continuing operations before unusual or infrequently occurring items totaled $76.4 million in 1993, an increase of $21.5 million, or 39 percent, over 1992. Earnings from the Company's exploration and production operations increased $1 million, and income from the refining, marketing, and transportation function improved $23.5 million. Income from farm, timber, and real estate operations increased $4.7 million, and the contribution from corporate activities declined $7.7 million.

In 1992, earnings from continuing operations before unusual or infrequently occurring items were $54.9 million, a decrease of $2.8 million from 1991. Income from exploration and production operations improved $12.5 million. Refining, marketing, and transportation profits declined $35.3 million from 1991, while earnings from farm, timber, and real estate operations increased $3.6 million. Corporate functions were profitable in 1992, a $16.4 million improvement compared to 1991.

In the following table, the Company's results of operations for the three years ended December 31, 1993 are presented by function, and unusual or infrequently occurring items are detailed. A review of the information presented follows the table.

(Millions of dollars)	1993	1992*	1991
Exploration and production			
United States	$ 32.7	42.2	27.1
Canada	6.3	1.2	(3.4)
United Kingdom	3.5	(1.6)	1.8
Spain	1.4	6.3	2.0
Other international	(7.0)	(12.2)	(4.1)
	36.9	35.9	23.4
Refining, marketing, and transportation			
United States	11.2	(6.0)	20.9
Western Europe	11.7	4.6	15.6
Canada	8.6	9.4	6.8
	31.5	8.0	43.3
Farm, timber, and real estate	13.1	8.4	4.8
Corporate and other	(5.1)	2.6	(13.8)
Income from continuing operations before unusual or infrequently occurring items	76.4	54.9	57.7
Refund and settlement of income tax matters	14.4	33.7	34.5
Provision for environmental remediation matters	(4.0)	(6.9)	--
Write-off of costs to acquire minority interest in a subsidiary not attributable to specific assets	--	--	(83.9)
Write-down of oil and gas properties	--	--	(33.3)
Settlement of insurance subsidiary litigation	--	--	10.6
Settlement of windfall profit tax dispute	--	--	4.8
Income (loss) from continuing operations	86.8	81.7	(9.6)
Cumulative effect of changes in accounting principles for			
Income taxes	31.8	--	--
Postretirement benefits other than pensions, net	(16.5)	--	--
Loss from discontinued contract drilling operations	--	--	(1.6)
Gain on disposal of contract drilling	--	23.9	--
Net income (loss)	$102.1	105.6	(11.2)

*The tax benefit of utilizing a financial net operating loss carryforward of $18.9, reported in the 1992 Consolidated Statement of Income as an extraordinary item, is allocated in this summary.

[GRAPH: Income Contribution by Operating Function]

EXPLORATION AND PRODUCTION--Earnings from exploration and production operations before unusual or infrequently occurring items were $36.9 million in 1993, $35.9 million in 1992, and $23.4 million in 1991. While the net increase in earnings in 1993 was modest, crude oil and liquids production was up 11 percent, natural gas production increased 10 percent to a record level of 274.9 million cubic feet a day, the average sales price for U.S. natural gas was up 20 percent, and exploration expenses declined 26 percent. These improvements were essentially offset by lower average crude oil sales prices throughout most of the year, exacerbated by a near-collapse at the end of 1993. The increase in 1992 was due primarily to a 20-percent increase in natural gas production and an eight-percent increase in the average sales price for U.S. natural gas. As partial offsets, crude oil and liquids production was down eight percent, average crude oil sales prices were generally lower, and exploration expenses were higher.

Oil and gas revenues for each of the last three years are shown by major operating area on page 59. A summary is presented in the following table.

(Millions of dollars)	1993	1992	1991
United States			
Crude oil............	$ 81.7	90.9	94.7
Natural gas..........	165.8	122.0	89.8
Canada			
Crude oil............	54.1	48.8	44.9
Natural gas..........	16.4	11.2	10.6
United Kingdom			
Crude oil............	38.4	41.0	56.6
Natural gas..........	11.0	13.4	10.2
Spain -- natural gas...	9.2	18.3	23.2
Other -- crude oil.....	8.0	10.0	17.0
Total................	$384.6	355.6	347.0

Daily production rates and weighted average sales prices are shown in the statistical summary on page 60. As subsequently reviewed, the Company made several acquisitions in 1993 that will result in substantial contributions to production levels in future years. Expected initial contributions of the significant acquisitions are indicated in the following paragraphs. These contributions may be partially offset by normal production declines from other producing properties.

Crude oil and liquids production in the U.S. was essentially unchanged during the two years ended December 31, 1993. In 1993, normal production declines nearly offset the restoration of production from certain fields damaged by Hurricane Andrew in August 1992. In 1992, a generally higher level of production during the first eight months of the year was offset by the temporary loss of production from fields damaged by the hurricane. Canadian production increased 25 percent in the current year following an eight-percent increase in 1992. The improvements include increases in heavy oil of 39 percent in 1993 and 13 percent in 1992, both resulting from an accelerated program to develop the Company's heavy oil reserves. This program may be adversely affected if the low level of crude oil prices at the end of 1993 continues. The Company's acquisition of a five-percent interest in a synthetic crude oil project (Syncrude), reviewed in subsequent sections, is expected to contribute approximately 9,000 barrels a day commencing January 1, 1994. Murphy's average production from the U.K. increased seven percent in 1993 and included 462 barrels a day as a result of the acquisition of an 11.26-percent interest in Block 16/17 ("T" Block) in the North Sea. This block commenced production in November 1993 and is expected to reach peak production in the second quarter of 1994, with the year projected to average 8,000 barrels a day. Production from the Ninian field in the North Sea was down one percent in 1993 and 24 percent in 1992. Production levels in both years were affected by construction activity in the field in preparation for transporting crude oil and natural gas from other fields through the Ninian facilities. Production in 1993 benefited from a successful workover program. The acquisition of an additional 3.82-percent interest in the Ninian field in early 1994 is projected to add 1,900 barrels a day to U.K. production.

Natural gas production in 1993 increased 15 percent in the U.S. to an all-time high and also reached record levels in Canada on the strength of a 21-percent increase. Natural gas production was about level in the U.K. Production in Spain, which is all from the Gaviota field, declined 51 percent. This field is nearing depletion, and the Company is in final negotiations to participate in a project to use the field's facilities to store third-party natural gas. The increase in U.S. natural gas production was partially due to commencement of production from a new field in the Gulf of Mexico during the fourth quarter of 1993. Two additional fields in the Gulf of Mexico commenced production early in 1994, and after allowing for normal declines from other properties, a 10-percent increase in U.S. natural gas production in 1994 could be achieved under market and other conditions existing at the end of 1993. Production of natural gas in 1992 increased 24 percent in the U.S. despite the adverse effects of Hurricane Andrew. Production increased 18 percent in Canada and 37 percent in the U.K., but declined 13 percent in Spain.

As previously indicated, worldwide crude oil prices were under pressure throughout most of 1993 and at year-end were well below levels of recent years. In the U.S., Murphy's 1993 average monthly sales prices for crude oil

[GRAPH: Range of U.S. Crude Oil Sales Prices]
[GRAPH: Range of U.S. Natural Gas Sales Prices]

ranged from $18.42 a barrel to $14.73 through November, before falling to $12.52 in December. U.K. average sales prices ranged from $19.51 a barrel to $15.22 over the first 11 months, and then declined to $13.56 in the final month of the year. Yearly averages were $16.60 a barrel in the U.S. and $16.63 in the U.K., both decreases of 12 percent when compared to 1992. In Canada, the average sales price for light oil was $15.01 a barrel, a decrease of 10 percent, and the average price for heavy oil declined 11 percent to $9.84. In December 1993, light and heavy oil sales prices averaged $10.73 a barrel and $6.58 a barrel, respectively. Average crude oil prices in 1992 were five percent lower in the U.S. and the U.K. and four percent lower for light oil in Canada. The average sales price for heavy oil in Canada ran counter to the trend and increased 21 percent compared to 1991.

In 1993, natural gas sales prices in the U.S. were more stable than in 1992 and ranged from $2.51 an MCF to $1.63. Prices for the year averaged $2.10 an MCF compared to $1.75 a year ago. In Canada, the average 1993 sales price for natural gas increased 21 percent, reflecting a gradual recognition of market conditions, as expiring contracts are being renewed at higher prices. Prices declined 19 percent in the U.K., mostly the result of a stronger U.S. dollar in relation to the pound sterling, and increased two percent in Spain.

Based on 1993 volumes and deducting taxes at marginal rates, each $1 a barrel and $.10 an MCF fluctuation in price would have affected annual exploration and production earnings by $7.2 million and $6.4 million, respectively. Consolidated net income could have been affected differently because of contrary or corollary effects on other business segments.

Production costs were $114.4 million in 1993, $110 million in 1992, and $106.2 million in 1991. These amounts are shown by major operating area on page 59. Geographically, costs per equivalent barrel during the last three years were as follows.

(Millions of dollars)	1993	1992	1991
United States..........	$3.21	3.00	3.42
Canada.................	3.70	4.18	4.90
United Kingdom.........	6.80	8.73	7.25
Spain..................	5.18	4.69	3.02

U.S. costs were down because of higher production volumes, offset in 1993 by higher insurance costs as a result of Hurricane Andrew. Reductions in Canada were due to higher production volumes and a strengthening of the U.S. dollar in relation to the Canadian dollar. The 1993 decline in U.K. cost per equivalent barrel was due to a cost-reduction program in the Ninian field, higher volumes, and strengthening of the U.S. dollar, partially offset by an increase in Ninian workover costs. The increase in 1992 was primarily due to lower production volumes.

The per-barrel equivalent costs for the most significant acquisitions -- "T" Block and Syncrude -- are estimated to be $2.70 and $11.30, respectively, in 1994.

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 58 and 59.

(Millions of dollars)	1993	1992	1991
Included in capital expenditures			
Dry hole costs.......	$21.5	29.9	21.3
Geological and geophysical costs..	7.6	8.9	11.1
Other costs..........	4.9	5.9	5.8
	34.0	44.7	38.2
Undeveloped lease amortization...........	12.1	17.4	14.1
Total.................	$46.1	62.1	52.3

Exploration expenses included in "Other international" in the table on page 24 totaled $6.6 million in 1993, $13.5 million in 1992, and $6.3 million in 1991.

Depreciation, depletion, and amortization totaled $141.2 million in 1993; $129.7 million in 1992; and $116.1 million in 1991, excluding write-downs of oil and gas properties. The increase in each year was primarily due to higher production volumes. In addition, as reviewed in Note B to the consolidated financial statements, adoption of Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes, resulted in an addition to net property, plant, and equipment, representing the tax effect of prior business combinations originally recorded net of tax. Depreciation, depletion, and amortization in 1993 included $10.9 million attributable to that adjustment; this amount was essentially offset by additional deferred income tax benefits. The 1993 acquisitions of proved properties will result in a substantial increase in depreciation, depletion, and amortization in 1994 as the acquired reserves are produced. The projected 1994 rates per barrel, including dismantlement costs, are $11.25 for "T" Block and $1.50 for Syncrude.

REFINING, MARKETING, AND TRANSPORTATION--Earnings from refining, marketing, and transportation operations before unusual or infrequently occurring items were $31.5 million in 1993, $8 million in 1992, and $43.3 million in 1991. Operations in the U.S. earned $11.2 million in 1993 compared to a

[GRAPH: Exploration Expenses]

loss of $6 million in 1992. U.S. earnings in 1991 totaled $20.9 million. Operations in Western Europe earned $11.7 million compared to $4.6 million in 1992 and $15.6 million in 1991. Canadian operations contributed $8.6 million to 1993 earnings compared to $9.4 million in 1992 and $6.8 million in 1991.

Unit margins (sales realizations less crude and other feedstocks, refining, and costs to point of delivery) averaged $.82 a barrel in the U.S. in 1993, $.48 in 1992, and $1.59 in 1991. U.S. product sales increased six percent in 1993 and 10 percent in 1992. Margins in the Company's southeastern marketing area remained under pressure during 1993 in a highly competitive environment. Margins in the upper-midwest area benefited from a strong asphalt market and were up substantially compared to a year ago. In 1992, the weak U.S. economy adversely affected product prices, and margins suffered in both areas compared to 1991.

Margins in Western Europe averaged $3.08 a barrel in 1993, $2.67 in 1992, and $3.52 in 1991. Sales of petroleum products increased three percent following a six-percent decline in 1992. Western European margins fluctuated widely in 1993, but were on an upward trend late in the year. Margins in 1992 were also affected by depressed economic activity and reflected a reduced level of demand for petroleum products.

Based on sales volumes for 1993 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 $14.9 million. Consolidated net income could have been affected differently because of contrary or corollary effects on other business segments.

The earnings decline in 1993 from purchasing, transporting, and reselling crude oil in Canada was due to lower crude trading volumes and increased pipeline operating costs, which more than offset higher pipeline throughputs. The improvement in 1992 was due to higher crude trading volumes and margins and an increase in throughput volumes.

FARM, TIMBER, AND REAL ESTATE--Earnings from farm, timber, and real estate operations were $13.1 million in 1993, $8.4 million in 1992, and $4.8 million in 1991. The increase in 1993 was due to a strong performance from timber operations, which earned $11.3 million, a $5.5 million improvement. Sales of finished lumber increased nine percent, and the average sales price increased 29 percent to a record $335 per thousand board feet. The earnings contribution from real estate operations totaled $2.4 million, up $.6 million on increased lot sales. Farming operations were hampered by adverse weather throughout the year and basically broke even in 1993 compared to earning $1.2 million in 1992. The improvement in 1992 earnings was primarily from timber operations, a $2.7 million increase, and farming operations, a $.9 million increase. Timber earnings were up mainly as a result of an increase in lumber sales combined with higher sales prices and improved operating efficiencies. The farms enjoyed favorable weather compared to 1991, when spring rains hurt early crops and led to higher operating costs. The earnings contribution from real estate operations increased $.1 million in 1992.

CORPORATE AND OTHER--This segment includes interest income and expense and corporate overhead not allocated to operating functions and ordinarily results in a net burden. The contribution to earnings in 1992 of $2.6 million was due to use of proceeds from sale of the contract drilling business, which resulted in a substantial increase in interest income from invested funds and a significant reduction in long-term debt and related interest expense when compared to 1991. During 1993, a substantial amount of the invested funds were used to acquire oil and gas properties, resulting in lower interest income compared to a year ago.

UNUSUAL OR INFREQUENTLY OCCURRING ITEMS--Net income for each of the three years ended December 31, 1993 included certain unusual or infrequently occurring items reviewed below. The information presented indicates the quarter in which the item occurred. Certain other quarterly information is presented on page 31.

. Refund and settlement of income tax matters--Gains of $11.3 million and $3.1 million were recorded in the first and fourth quarters of 1993, respectively, for refund and settlement of income tax matters in the U.K. A $21.5 million gain for refund of U.S. income taxes was recorded in the second quarter of 1992, and a $12.2 million gain for settlement of income tax matters in the U.K. and Gabon was recorded in the third quarter of 1992. A gain of $34.5 million for refund of U.S. income taxes was recorded in the third quarter of 1991.
. Provision for environmental remediation matters--An after-tax provision of $4 million was recorded in the fourth quarter of 1993 for environmental remediation matters. After-tax provisions of $3.6 million and $3.3 million were recorded in the second and fourth quarters of 1992, respectively.
. Write-off of costs to acquire minority interest in a subsidiary not attributable to specific assets--The second quarter of 1991 included a charge of $83.9 million related to acquisition of the minority interest in Ocean Drilling & Exploration Company. The charge represents write-off of the cost of acquisition in excess of the fair values of the assets

[GRAPH: Average Sales Price of U.S. Refined Products]
[GRAPH: Average Sawmill Margin]
[GRAPH: Selling and General Expenses]

acquired and includes estimated expenses of consolidating the organizations. (See Note C to the consolidated financial statements.)

- Write-down of oil and gas properties -- The second quarter of 1991 included a loss from the write-down in carrying value of certain oil and gas properties. The write-down included $17.3 million for Canadian properties and $16 million for U.S. properties.
- Settlement of insurance subsidiary litigation--Litigation relating to the liquidation of an insurance subsidiary was settled in early 1992, and the fourth quarter of 1991 reflected a $10.6 million reversal of the excess portion of a loss provision made in 1987. (See Note E to the consolidated financial statements.)
- Settlement of windfall profit tax dispute--Settlement of the dispute resulted in a first quarter 1991 gain of $4.8 million.
- Discontinued operations--The first quarter of 1992 included a net gain of $20.3 million from sale of the contract drilling business; the fourth quarter included a $3.6 million adjustment to increase that gain. In 1991, the discontinued contract drilling business had losses of $5 million, $1 million, and $.2 million in the first, second, and fourth quarters, respectively, partially offset by income of $4.6 million in the third quarter. (See Note D to the consolidated financial statements.)
- Cumulative effect of changes in accounting principles--The first quarter of 1993 included a net benefit of $15.3 million for the cumulative effect of accounting changes that were adopted effective January 1, 1993. (See Note B to the consolidated financial statements.)

Excluding the cumulative effect of accounting changes in 1993 and discontinued contract drilling operations in 1992 and 1991, the income (loss) effects of unusual or infrequently occurring items are summarized by function in the following table for the three years ended December 31, 1993.

(Millions of dollars)	1993	1992	1991
Exploration and production			
United States........	$ --	(.2)	(11.1)
Canada...............	--	--	(17.3)
United Kingdom.......	14.4	3.3	--
Other international..	--	4.2	--
	14.4	7.3	(28.4)
Refining, marketing, and transportation			
United States........	(3.9)	(5.9)	--
Western Europe.......	(.1)	(2.8)	--
	(4.0)	(8.7)	--
Corporate and other......	--	28.2	(38.9)
Total...............	$10.4	26.8	(67.3)

Certain of the unusual or infrequently occurring items had a significant effect on the Company's consolidated effective income tax rates, which were 35 percent in 1993, nine percent in 1992, and 124 percent in 1991. (See Note J to the consolidated financial statements.)

IMPACT OF INFLATION

General inflation was moderate during the last three years in most countries where the Company operates; however, Murphy's revenues and costs do not necessarily correlate to changes in the general inflation rate. The Company's 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/demand balance in the near future. Natural gas prices are affected by supply and demand and by the fact that delivery of supplies is generally restricted to specific geographical areas. Lumber and farm commodities reflect the balance between supply and demand, while real estate sales respond to changes in the general economy and interest rates.

CAPITAL EXPENDITURES

As shown on page 23, capital expenditures were $637.6 million in 1993 compared to $235.6 million in 1992 and $223.2 million in 1991. Capital expenditures for exploration and production activities totaled $537 million in 1993, 84 percent of the Company's total capital expenditures for the year, and included $259.7 million for acquisition of proved properties. Excluding this amount, exploration and production activities accounted for 73 percent of 1993 capital expenditures and totaled $277.3 million--$4.4 million for acquisition of undeveloped leases, $60.2 million for exploration activities, and $212.7 million for development projects. Development expenditures included $67.7 million for oil fields in Ecuador. The expenditures for acquisition of proved properties included $143.1 million for the 11.26-percent interest in "T" Block. The five-percent interest in the Syncrude project in Canada accounted for $109 million of the proved property acquisition costs, $67.4 million of which was noncash and seller-financed by nonrecourse debt. Development expenditures associated with properties acquired in 1993 included $23.7 million for "T" Block and $38.4 million attributable to a 6.5-percent interest in the Hibernia oil field, offshore Newfoundland. A 1992 acquisition of a 30-percent interest in Viosca Knoll Block 783 required development expenditures of $20.2 million during 1993. Exploration and production capital expenditures are shown by major operating area on page 58.

[GRAPH: Capital Expenditures in 1993]

Amounts shown under "Other" in 1993 include $4.4 million for an unsuccessful well in Peru.

Refining, marketing, and transportation expenditures, detailed below, were $86.9 million in 1993, or 13 percent of total capital expenditures.

(Millions of dollars)	1993	1992	1991
Refining			
United States	$64.3	36.9	31.9
United Kingdom	2.1	11.1	12.7
Total refining	66.4	48.0	44.6
Marketing			
United States	6.9	6.8	9.5
United Kingdom	9.9	6.5	5.3
Canada	.1	.8	.4
Total marketing	16.9	14.1	15.2
Transportation			
United States	.2	.6	.3
Canada	3.4	5.4	3.0
Total transportation	3.6	6.0	3.3
Total	$86.9	68.1	63.1

Refining expenditures of $66.4 million included $32.3 million at Meraux, Louisiana, and $5.1 million at Superior, Wisconsin, for distillate desulfurization projects; $6.1 million at Meraux for sour crude processing facilities; and $13.7 million related to environmental standards and regulations. The remaining $9.2 million was for replacements and improvements and included $6.1 million at Meraux, $1.3 million at Superior, and $1.8 million at Milford Haven. Marketing expenditures of $16.9 million included the costs of sites and new service stations, acquisition of stations, and improvements and normal replacements at existing stations and terminals. The U.S. expenditures included $.6 million for replacement of underground storage tanks and installation of leak detection systems at stations.

Deltic spent $5.7 million for real estate development, $3.6 million for timber operations including sawmill upgrades, and $.4 million on the farms.

CASH FLOWS

Cash provided by continuing operations was $363 million in 1993, $284.2 million in 1992, and $213.6 million in 1991. Resolution of certain tax matters provided $11.8 million of cash in 1993, $41.5 million in 1992, and $39.3 million in 1991. Cash provided by nonrecourse debt arrangements totaled $27.7 million in 1993. Disposition of assets provided $365.4 million in 1992, primarily from sale of the contract drilling business. Cash provided by discontinued operations was $26 million in 1991.

Capital expenditures required $570.2 million of cash in 1993, $235.6 million in 1992, and $223.2 million in 1991. These amounts included $34 million, $44.7 million, and $38.2 million of exploration expenditures that were expensed. Other significant cash outlays during the three years included $217 million in 1992 for net reductions of debt. Cash used for dividends to stockholders was $55.9 million in 1993; $53.8 million in 1992; and $49.2 million in 1991, including $2 million to minority stockholders of a subsidiary. The Company also repurchased 48,400 shares of its Common Stock in 1993 and 161,100 shares in 1992 for $1.6 million and $5.4 million, respectively. Cash used for investing activities of discontinued operations totaled $18.4 million in 1991, primarily for capital expenditures.

FINANCIAL CONDITION

Year-end working capital totaled $130.2 million in 1993, $371.7 million in 1992, and $156.2 million in 1991. The changes during the two most recent years primarily reflect in 1992 the cash sale of the Company's contract drilling business for $372 million and the retirement of most debt, and in 1993 the investments to expand the Company's oil and gas business. The current level of working capital does not fully reflect the Company's liquidity position, as the relatively low historical costs assigned to inventories under LIFO accounting were $46.3 million below current costs at December 31, 1993. Cash and equivalents at the end of 1993 totaled $141.2 million compared to $377.8 million a year ago and $242.1 million at year-end 1991.

Long-term obligations increased $84.3 million and were $109.2 million at year-end, 8.2 percent of total capital employed, and included $87.5 million of nonrecourse debt incurred in connection with the acquisition and development of proved properties. Long-term obligations totaled $24.9 million at the end of 1992 compared to $193.1 million at year-end 1991. Stockholders' equity was $1.2 billion at each year-end. A summary of transactions in the equity accounts is presented on page 36.

The primary sources of the Company's liquidity are internally generated funds, access to outside financing by bank borrowings, 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. Because of the Company's current financial position, no problem is anticipated in meeting future requirements for funds. Current financing arrangements are set forth in Note H to the consolidated financial statements.

The Company had commitments of $274 million for capital projects in progress at December 31, 1993.

[GRAPH: Sources of Cash and Cash Equivalents in 1993]
[GRAPH: Uses of Cash and Cash Equivalents in 1993]

ENVIRONMENTAL OBLIGATIONS

The Company's worldwide operations are subject to numerous laws and regulations designed to protect the environment. In addition, the Company may be involved in personal injury claims, allegedly caused by exposure to materials manufactured or used by the Company. Under the Company's accounting policies, liabilities for environmentally related obligations are recorded when such obligations are probable and the cost can be reasonably estimated. In instances where there is a range of reasonably estimated costs, the Company will record the most likely amount, or if no amount is most likely, the minimum of the range will be recorded. The need to adjust amounts recorded is reviewed quarterly. Actual cash expenditures often follow recognition of the obligation by a number of years.

The Company currently operates or has previously operated certain sites or facilities, including refineries, oil and gas fields, service stations, and terminals, for which known or potential obligations for environmental remediation exist. During 1993, the Company increased its reserve for remediation obligations by a pretax provision of $6.3 million. Included in the reserve are certain amounts that are based on anticipated regulatory approval of proposed remediation processes involving a land farm, formerly used for disposal of refinery waste, and closure of water basins. If regulatory authorities require more costly alternatives than the proposed processes, future expenditures could increase by up to an estimated $9 million above the amount reserved.

The Company has received notices from the U.S. Environmental Protection Agency that it is a Potentially Responsible Party (PRP) at two Superfund sites and has been assigned responsibility by defendants at another Superfund site. In addition, the Company is aware of three other sites at which it could be named as a PRP. The potential total cost to all parties to perform necessary remediation work at these sites is substantial. However, based on information currently available, the Company is a de minimus party, with assigned or potentially assigned responsibility of less than one percent at each site. The Company has recorded a reserve totaling $.1 million for these sites. Due to these minor percentages, the Company does not expect that its remediation costs at these sites will be material to its financial condition. Additional information may become known in the future that would alter this assessment, including a requirement to bear a pro rata share of costs attributable to nonparticipating PRP's or indications of additional responsibility by the Company.

Although the Company is not aware of any environmental matters that might have a material 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 have a material impact on the results of operations in a future period.

The Company believes that certain of the environmental remediation obligations are covered by insurance; however, the issue is the subject of ongoing litigation and no assurance can be given that the Company's position will be sustained. Therefore, no insurance recoveries have been used to reduce the environmental liabilities recorded at December 31, 1993.

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 $2.6 million in 1993.

In addition to remediation and other recurring expenditures, Murphy commits a substantial amount of its capital expenditure program for compliance with environmental laws and regulations. Such capital expenditures were approximately $74 million in 1993 and are expected to be $58 million in 1994.

OUTLOOK

In planning for 1994, prices for the Company's products remain an uncertainty. Crude oil prices, which dropped sharply in late 1993, remain at depressed levels in early 1994, and prices for natural gas and product margins have fluctuated significantly in recent months. In such an environment, constant reassessment of spending plans is required. The Company's capital expenditure budget for 1994 was prepared during the fall of 1993 and provides for expenditures of $444 million. A major portion of this amount, $313 million or 70 percent, is allocated for exploration and production. Geographically, about 36 percent of the exploration and production money is designated for the U.S., with primary emphasis in the Gulf of Mexico; 30 percent for Canada, including $49 million for development of the Hibernia oil field (most of which will be funded by additional nonrecourse debt); 17 percent for development of oil fields in Ecuador; and the remaining 17 percent for other overseas operations. Capital expenditures for refining, marketing, and transportation are budgeted at $108 million, including $19 million to expand sour crude processing capabilities at the Meraux refinery and $13 million for environmental compliance projects at the Superior refinery. Budgeted marketing capital expenditures total $12 million in the U.S. and $14 million in the U.K. Other budgeted expenditures include $16 million for farm, timber, and real estate, about equally divided between real estate and sawmills, and $7 million for miscellaneous items. Capital and other expenditures are under constant review, and these budgeted amounts may be adjusted to reflect changes in estimated cash flow.

QUARTERLY INFORMATION

(Millions of dollars except per share amounts)	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	YEAR
			1993(1)		
Sales and other operating revenues	$390.9	421.5	410.4	413.9	1,636.7
Income from continuing operations before income taxes	23.3	42.2	33.8	34.3	133.6
Income from continuing operations	23.9	22.7	20.2	20.0	86.8
Cumulative effect of changes in accounting principles	15.3	--	--	--	15.3
Net income	39.2	22.7	20.2	20.0	102.1
Per Common share(2)					
Income from continuing operations	.53	.51	.45	.45	1.94
Cumulative effect of changes in accounting principles	.34	--	--	--	.34
Net income	.87	.51	.45	.45	2.28
Dividends	.30	.30	.325	.325	1.25
Market Price					
High	42 3/8	45 1/8	47 3/4	47 7/8	47 7/8
Low	33	38 7/8	39 1/2	37 5/8	33
			1992(1)		
Sales and other operating revenues	$359.2	409.9	415.3	447.0	1,631.4
Income (loss) from continuing operations before income taxes	5.3	36.1	(1.0)	28.9	69.3
Income (loss) from -- Continuing operations	(1.1)	27.5	14.7	21.7	62.8
Discontinued operations	20.3	--	--	3.5	23.8
Income before extraordinary item	19.2	27.5	14.7	25.2	86.6
Extraordinary item(3)	4.1	6.4	2.4	6.1	19.0
Net income	23.3	33.9	17.1	31.3	105.6
Per Common share(2)					
Income (loss) from -- Continuing operations	(.02)	.61	.33	.48	1.40
Discontinued operations	.45	--	--	.08	.53
Income before extraordinary item	.43	.61	.33	.56	1.93
Extraordinary item(3)	.09	.14	.05	.14	.42
Net income	.52	.75	.38	.70	2.35
Dividends	.30	.30	.30	.30	1.20
Market Price					
High	37 1/4	38 3/8	37 7/8	37 7/8	38 3/8
Low	32 3/8	32 5/8	33 1/8	34 1/4	32 3/8

(1) The amounts reflected in continuing operations include certain unusual or infrequently occurring gains (losses) that are reviewed in Management's Discussion and Analysis. Quarterly totals, in millions of dollars, and the effect per Common share are reported in the following table.

	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	YEAR
1993					
Quarterly totals	$ 11.3	--	--	(.9)	10.4
Per Common share(2)	.25	--	--	(.02)	.23
1992					
Quarterly totals	$ --	17.9	12.2	(3.3)	26.8
Per Common share(2)	--	.40	.27	(.07)	.60

(2) Based on average number of Common and Common equivalent shares outstanding during the respective periods.

(3) Represents a credit for tax benefit from utilization of a financial net operating loss carryforward. This credit offsets an equivalent charge in continuing operations.

Market prices of Common Stock are as quoted on the New York Stock Exchange. There were 5,265 stockholders of record at December 31, 1993.

REPORT OF MANAGEMENT

Preparation and integrity of the accompanying consolidated financial statements and other financial data are the responsibility of management. 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. Effectiveness of the controls is monitored by the Company's audit staff, which independently and systematically evaluates and formally reports on the adequacy and effectiveness of components of the system.

Our independent auditors, KPMG Peat Marwick, 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 Peat Marwick 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.

Annually the Board of Directors appoints an Audit Committee 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 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
Murphy Oil Corporation:

We have audited the accompanying consolidated balance sheets of Murphy Oil Corporation and Consolidated Subsidiaries as of December 31, 1993 and 1992, and the related consolidated statements of income, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 1993. 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, 1993 and 1992, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 1993, in conformity with generally accepted accounting principles.

As discussed in Note B to the consolidated financial statements, the Company adopted the provisions of Financial Accounting Standards Board's Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, and Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes, in 1993.

KPMG PEAT MARWICK

Shreveport, Louisiana
March 4, 1994

CONSOLIDATED STATEMENTS OF INCOME

(Thousands of dollars except per share amounts)			
Years Ended December 31	1993	1992	1991
REVENUES			
Sales	$1,599,833	1,596,394	1,573,314
Other operating revenues	36,835	35,047	27,621
Interest and other revenues	34,469	53,974	89,151
Total revenues	1,671,137	1,685,415	1,690,086
COSTS AND EXPENSES			
Crude oil, products, and operating expenses	1,247,831	1,301,485	1,229,117
Exploration expenses, including undeveloped lease amortization	46,071	62,097	52,339
Selling and general expenses	65,195	72,861	71,842
Depreciation, depletion, and amortization	176,213	164,822	149,648
Write-off of costs to acquire minority interest in a subsidiary not attributable to specific assets	--	--	85,644
Write-down of oil and gas properties	--	--	43,471
Interest expense	7,614	17,079	30,982
Interest capitalized	(5,414)	(2,254)	(2,972)
Total costs and expenses	1,537,510	1,616,090	1,660,071
Income from continuing operations before income taxes and minority interest	133,627	69,325	30,015
Federal and state income taxes	40,383	19,018	23,682
Foreign income taxes (benefits)	6,446	(12,454)	13,475
Minority interest in income of a subsidiary	--	--	2,465
Income (loss) from continuing operations	86,798	62,761	(9,607)
DISCONTINUED OPERATIONS			
Loss from operations, net of minority interest	--	--	(1,550)
Gain on disposal	--	23,855	--
Income (loss) from discontinued operations	--	23,855	(1,550)
Income (loss) before extraordinary item and cumulative effect of changes in accounting principles	86,798	86,616	(11,157)
Extraordinary tax benefit from utilization of financial net operating loss carryforward	--	18,949	--
Cumulative effect of changes in accounting principles	15,338	--	--
NET INCOME (LOSS)	$ 102,136	105,565	(11,157)
PER COMMON SHARE			
Income (loss) from continuing operations	$ 1.94	1.40	(.24)
Income (loss) from discontinued operations	--	.53	(.04)
Income (loss) before extraordinary item and cumulative effect of changes in accounting principles	1.94	1.93	(.28)
Extraordinary item	--	.42	--
Cumulative effect of changes in accounting principles	.34	--	--
Net income (loss)	$ 2.28	2.35	(.28)
Average Common shares outstanding	44,856,635	44,931,208	39,457,719

See notes to consolidated financial statements, page 37.

CONSOLIDATED BALANCE SHEETS

(Thousands of dollars)		
December 31	1993	1992
ASSETS		
Current assets		
Cash and interest-bearing deposits	$ 26,876	137,861
Marketable securities	114,349	239,984
Cash and cash equivalents	141,225	377,845
Accounts receivable, less allowance for doubtful accounts of $5,379 in 1993 and $6,318 in 1992	196,214	241,397
Inventories		
Crude oil and raw materials	76,741	60,977
Finished products	42,959	50,497
Materials and supplies	32,323	25,383
Prepaid expenses	35,042	42,509
Deferred income taxes	18,497	--
Total current assets	543,001	798,608
Investments and noncurrent receivables	42,518	27,403
Property, plant, and equipment, at cost less accumulated depreciation, depletion, and amortization of $2,180,732 in 1993 and $2,064,488 in 1992	1,549,250	1,073,179
Deferred charges and other assets	34,090	37,324
	$2,168,859	1,936,514
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term obligations	$ 10,859	3,662
Short-term notes payable	--	2,795
Accounts payable	255,332	251,462
Accrued insurance obligations	28,420	34,941
Accrued taxes other than taxes on income	33,303	29,392
Other accrued liabilities	55,551	62,733
Income taxes	29,294	41,941
Total current liabilities	412,759	426,926
Notes payable and other long-term obligations	21,709	24,929
Nonrecourse debt of a subsidiary	87,509	--
Deferred income taxes	117,571	43,918
Reserve for dismantlement costs	123,107	112,719
Reserve for major repairs	26,023	19,139
Deferred credits and other liabilities	157,831	108,795
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 in 1993 and 1992	48,775	48,775
Capital in excess of par value	507,292	506,962
Retained earnings	772,172	725,981
Currency translation adjustments	(1,514)	21,595
Unamortized restricted stock awards	(660)	(835)
Treasury stock	(103,715)	(102,390)
Total stockholders' equity	1,222,350	1,200,088
	$2,168,859	1,936,514

See notes to consolidated financial statements, page 37.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of dollars)			
Years Ended December 31	1993	1992	1991
OPERATING ACTIVITIES			
Income (loss) from continuing operations	$ 86,798	62,761	(9,607)
Adjustments to reconcile income (loss) to net cash provided by operating activities			
Depreciation, depletion, amortization	176,213	164,822	149,648
Write-off of costs to acquire minority interest in a subsidiary not attributable to specific assets, net of taxes	--	--	83,944
Write-down of oil and gas properties, net of taxes and minority interest	--	--	33,260
Expenditures for major repairs and dismantlement costs	(13,391)	(3,455)	(29,757)
Exploratory expenditures charged against income	33,945	44,701	38,259
Amortization of undeveloped leases	12,126	17,396	14,080
Deferred and noncurrent income tax charges (credits)	36,970	(21,740)	23,175
Charge equivalent to federal income tax benefit of operating loss carryforward	--	18,949	--
Minority interest in income of a subsidiary	--	--	4,816
Gains from disposition of assets	(1,474)	(1,709)	(697)
Other -- net	32,422	39,399	20,005
	363,609	321,124	327,126
(Increase) decrease in operating working capital other than cash and cash equivalents	418	(30,917)	(96,436)
Cumulative effect of accounting changes on working capital	25,437	--	--
Net expenditures under insurance claim to repair hurricane damage	(18,172)	(11,560)	--
Other adjustments related to continuing operations	(8,319)	5,512	(17,055)
Net cash provided by continuing operations	362,973	284,159	213,635
Net cash provided by discontinued operations	--	--	26,008
Net cash provided by operating activities	362,973	284,159	239,643
INVESTING ACTIVITIES			
Capital expenditures requiring cash	(570,186)	(235,565)	(223,221)
Proceeds from sale of property, plant, and equipment	5,721	3,716	12,105
Other continuing operations -- net	2,481	(2,847)	(1,661)
Sale of discontinued operations	--	361,673	--
Investing activities of discontinued operations	--	--	(18,390)
Net cash provided (required) by investing activities	(561,984)	126,977	(231,167)
FINANCING ACTIVITIES			
Additions to notes payable and other long-term obligations	161	236	49,760
Reductions of notes payable and other long-term obligations	(3,738)	(182,355)	(67,479)
Increase in nonrecourse debt of a subsidiary	27,693	--	--
Increase (decrease) in short-term notes payable	(2,795)	(34,885)	32,175
Dividends paid			
Murphy shareholders	(55,945)	(53,821)	(47,234)
Minority shareholders	--	--	(2,006)
Purchase of Common Stock for treasury	(1,636)	(5,440)	--
Net cash required by financing activities	(36,260)	(276,265)	(34,784)
Effect of exchange rate changes on cash and cash equivalents	(1,349)	(7,230)	1,951
Net increase (decrease) in cash and cash equivalents	(236,620)	127,641	(24,357)
(Increase) decrease applicable to discontinued operations	--	8,139	(3,676)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS OF CONTINUING OPERATIONS	(236,620)	135,780	(28,033)
Cash and cash equivalents of continuing operations at January 1	377,845	242,065	270,098
CASH AND CASH EQUIVALENTS OF CONTINUING OPERATIONS AT DECEMBER 31	$ 141,225	377,845	242,065

See notes to consolidated financial statements, page 37.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(Thousands of dollars)			
Years Ended December 31	1993	1992	1991
CUMULATIVE PREFERRED STOCK -- par $100, authorized 400,000 shares, none issued	$ --	--	--
COMMON STOCK			
Balance at beginning of year	48,775	48,775	37,742
Add 11,032,956 shares issued to acquire minority interest in a subsidiary	--	--	11,033
Common Stock, par $1.00, authorized 80,000,000 shares, issued 48,775,314 shares at end of year	48,775	48,775	48,775
CAPITAL IN EXCESS OF PAR VALUE			
Balance at beginning of year	506,962	506,559	150,977
Issuance of Common Stock to acquire minority interest in a subsidiary	--	--	355,499
Exercise and surrender of stock options	224	115	24
Restricted stock transactions	106	288	--
Capital transactions of subsidiaries	--	--	59
Capital in excess of par value at end of year	507,292	506,962	506,559
RETAINED EARNINGS			
Balance at beginning of year	725,981	674,237	732,628
Net income (loss) for the year	102,136	105,565	(11,157)
Cash dividends -- $1.25 a share in 1993, $1.20 a share in 1992 and 1991	(55,945)	(53,821)	(47,234)
Retained earnings at end of year	772,172	725,981	674,237
CURRENCY TRANSLATION ADJUSTMENTS			
Balance at beginning of year	21,595	69,223	50,718
Increase applicable to acquisition of minority interest in a subsidiary	--	--	18,399
Translation gains (losses) during the year	(23,109)	(47,628)	106
Currency translation adjustments at end of year	(1,514)	21,595	69,223
UNAMORTIZED RESTRICTED STOCK AWARDS			
Balance at beginning of year	(835)	--	--
Stock awards	--	(1,180)	--
Amortization, forfeitures, and changes in price of Common Stock	175	345	--
Unamortized restricted stock awards at end of year	(660)	(835)	--
TREASURY STOCK -- 3,967,631 shares of Common Stock in 1993, 3,931,076 shares in 1992, and 3,809,785 shares in 1991, at cost	(103,715)	(102,390)	(97,975)
TOTAL STOCKHOLDERS' EQUITY	$1,222,350	1,200,088	1,200,819

See notes to consolidated financial statements, page 37.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE A - SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation--The consolidated financial statements include the accounts of Murphy Oil Corporation and all majority-owned subsidiaries. The contract drilling business segment, which was sold effective January 1, 1992, is accounted for as discontinued operations. Information presented in the footnotes is based on continuing operations unless otherwise indicated. Investments in jointly owned companies are accounted for by the equity method. All significant intercompany accounts and transactions have been eliminated.

Marketable Securities--Marketable securities (short-term investments in government securities, or with government securities as collateral, that have a maturity of three months or less from the date of purchase) are recorded at cost plus accrued interest, which approximates market value, and are treated as cash equivalents.

Inventories--Inventories of crude oil and refined products are generally valued at cost applied on a last-in, first-out (LIFO) basis, which in the aggregate is lower than market. Raw materials and lumber are stated at the lower of average cost or market. Materials and supplies are valued at the lower of average cost or estimated value.

Exploration and Development--The Company uses the successful efforts method of accounting for exploration and development expenditures. Direct acquisition costs of developed and undeveloped leases are capitalized. Cost of undeveloped leases on which proved reserves are found is transferred to producing oil and gas properties. Each undeveloped lease with significant acquisition cost is reviewed periodically, and a valuation allowance is provided for any estimated decline in value. Cost of all other undeveloped leases is amortized over the estimated average holding period of the leases. Costs of exploratory drilling are initially capitalized, but if proved reserves are not found, the costs are subsequently expensed. All other exploratory costs are charged to expense as incurred. Development costs are capitalized, including the cost of unsuccessful development wells. Worldwide undiscounted future net revenues are compared annually to net capitalized cost of proved properties to determine if an impairment has occurred in the amount capitalized. As warranted by events, significant, high-cost properties are assessed for permanent impairment based on discounted future net revenues.

Depreciation and Depletion--Depreciation and depletion of producing oil and gas properties are provided under the unit-of-production method on a property-by-property basis. Developed reserves are used to compute unit rates for unamortized tangible and intangible development costs, and proved reserves are used for unamortized leasehold costs. Estimated costs (net of salvage value) of dismantling oil and gas production facilities, including abandonment and site restoration costs, are computed by the Company's engineers and included in depreciation and depletion using the unit-of-production method. Depreciation of refining and marketing facilities is calculated using the composite straight-line method. Depletion of timber is based on board feet cut. Office buildings, pipelines, and other properties are depreciated by individual unit based on the straight-line method.

Asset Retirements--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.

Major Repairs--Provisions are made for refinery turnarounds by monthly charges to expense. Costs incurred are charged against the reserve. All other maintenance and repair costs are charged to expense. Renewals and betterments are capitalized.

Environmental Liabilities--A provision for environmentally related obligations is recorded by a charge to expense when it is determined that 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 expenditures that have future economic benefit are capitalized.

Income Taxes--Effective January 1, 1993, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 109, Accounting for Income Taxes. (See Note B to the consolidated financial statements for a discussion of the effects of this change.) Under the asset and liability method of accounting for income taxes required by SFAS No. 109, deferred tax assets and liabilities are based on differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities, and are measured using the enacted tax rates that are assumed will be in effect when the differences are expected to reverse. The effect on deferred taxes of a change in a tax rate is recognized in the statement of income for the period covering the enactment date. Provision for petroleum revenue taxes payable to the U.K. government is based on the estimated effective tax rate over the life of certain properties.

Employee Retirement Plans--Retirement benefits for substantially all employees of the Company are funded by contributions to trustees. Retirement expense is computed in accordance with SFAS No. 87, Employers' Accounting for Pensions.

Foreign Currency Translation--Local currency is the "functional currency" used for recording operations in Canada and Spain and the majority of activities in the U.K. and Gabon. The U.S. dollar is the functional currency used to record all other operations. Gains or losses that result from translating accounts from foreign functional currencies into U.S. dollars are included as a separate component of stockholders' equity entitled "Currency Translation Adjustments." Gains or losses that result from specific transactions in a currency other than the functional currency are included in net income.

Foreign Currency Contracts--Foreign currency contracts may be executed to hedge future commitments or to offset certain U.S. dollar transactions. Gains or losses on capital hedge transactions are included in property, plant, and equipment; gains or losses on hedged nonrecourse debt are recorded in "Currency Translation Adjustments;" and other gains or losses are included in net income.

Excise Taxes on Refined Products--Taxes collected on the sales of refined products and remitted to governmental agencies are not included in revenues or costs and expenses.

Net Income per Common Share--This amount is computed by dividing the weighted average number of Common and Common equivalent shares outstanding during each reporting period into net income.

NOTE B--ACCOUNTING CHANGES--Effective January 1, 1993, the Company elected the immediate recognition basis for implementing SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions. This accounting standard requires the actuarially determined costs of postretirement benefits (supplemental health care and life insurance) to be accrued over the estimated service lives of employees. Previously, the Company expensed these costs when incurred. The cumulative effect of adopting SFAS No. 106, which was recorded as of January 1, 1993 based on a nine-percent discount rate, resulted in a charge against net income of $16,502,000, $.37 a share, after an income tax effect of $8,500,000. Excluding the charge against income for the cumulative effect, the adoption of SFAS No. 106 did not significantly affect 1993 net income.

Effective January 1, 1993, the Company also adopted SFAS No. 109, Accounting for Income Taxes, without restating prior years' results. The cumulative effect of the change on 1993 net income was a benefit of $31,840,000, $.71 a share. In addition, net property, plant, and equipment was increased $82,092,000, and a corresponding increase was recorded in deferred income tax liability, representing the tax effect of prior business combinations originally recorded net of tax. The Company previously accounted for income taxes using the deferred method prescribed by Accounting Principles Board Opinion No. 11. Under this method, deferred income taxes were recognized for certain revenues and expenses that affected financial and taxable income in different years, were recorded using the tax rates applicable for the year of calculation, and were not adjusted for subsequent tax rate changes.

As a result of adopting SFAS No. 109, 1993 income from continuing operations before income taxes was reduced $10,916,000. This reduction was primarily due to increased depreciation, depletion, and amortization expense caused by the adjustment for prior business combinations. The increased expense was essentially offset by additional deferred tax benefits.

In November 1992, the Financial Accounting Standards Board issued SFAS No. 112, Employers' Accounting for Postemployment Benefits, which established standards of accounting for the cost of benefits provided former or inactive employees before they retire. The Company's accounting practices already complied with the new standard in all material aspects; therefore, no cumulative effect of a change in accounting principle was required upon adoption in 1993.

NOTE C--ACQUISITION OF MINORITY SHAREHOLDERS' OWNERSHIP OF OCEAN DRILLING & EXPLORATION COMPANY (ODECO) -- On June 3, 1991, Murphy offered shareholders of ODECO (at that time a 61-percent owned subsidiary) .55 share of Murphy Common Stock for each share of ODECO Common Stock outstanding that was not then owned by Murphy. Required shares of ODECO Common Stock were tendered, and a short-form merger was completed under Delaware law, with ODECO, later renamed Murphy Exploration & Production Company, becoming a wholly owned subsidiary of Murphy. A total of 11,032,956 shares of Murphy Common Stock were issued in the exchange.

The acquisition was accounted for by Murphy using the purchase method. Cost of the acquisition that exceeded the book value of net tangible assets acquired was allocated to those properties up to their fair values at the date of acquisition.

Unallocated amounts that exceeded fair values of the assets and estimated expenses of consolidating the organizations were written off (Write-off) by a charge against income of $85,644,000, $83,944,000 net of tax. The following pro forma information reflects results of operations for the year 1991 as though the acquisition had occurred at January 1, 1991 excluding the Write-off.

(Thousands of dollars, except per share amounts)	
PRO FORMA	1991
Revenues..............................	$ 1,690,086
Income from continuing operations.....	68,416
Net income............................	62,007
Per Common share	
Income from continuing operations...	1.52
Net income..........................	1.38
Average Common shares outstanding.....	44,996,612

NOTE D -- DISCONTINUED OPERATIONS -- Effective January 1, 1992, the Company sold its contract drilling business for $372,127,000 in cash and reported a net gain in 1992 of $23,855,000 from disposal of these operations. As a result of the sale, contract drilling activities have been accounted for as discontinued operations and are presented as net amounts in the Consolidated Statements of Income. Selected operating results in 1991 for the contract drilling business included revenues of $189,051,000, income tax provisions totaling $2,885,000, and a loss from operations, net of minority interest, of $1,550,000.

NOTE E -- MENTOR LIQUIDATION -- In January 1992, ODECO settled litigation related to its discontinued casualty insurance operations that were primarily conducted by a Bermuda subsidiary, Mentor Insurance Limited (Mentor), which is in liquidation. As a part of the settlement, all Mentor-related litigation was dismissed, and ODECO paid $500,000 to the Mentor estate. In settlement of separate litigation with certain banks, ODECO had previously recorded a $100,000,000 loss in 1987 relating to letters of credit issued by such banks on Mentor's behalf. In 1991, the Company included $10,544,000 in "Interest and Other Revenues," primarily representing a reduction of the loss recorded in 1987.

NOTE F -- INVENTORIES -- Inventories valued at cost under the LIFO method totaled $89,721,000 at December 31, 1993 and $77,607,000 at December 31, 1992. These amounts were $46,255,000 and $78,005,000, respectively, less than such inventories would have been valued using the FIFO method.

The Company has entered into crude oil price swap agreements to reduce exposure to changes in the cost of 3,500,000 barrels of the Company's 1996 and 1997 crude oil requirements for U.S. refineries. Any gains anticipated under these agreements will be deferred, with the cost of the related crude oil being adjusted when the agreements are settled. Any losses will similarly be deferred unless at any time prior to settlement the estimated realizable value of products is less than the cost of products produced from crude, as adjusted for the effect of these agreements.

NOTE G -- PROPERTY, PLANT, AND EQUIPMENT

(Thousands of dollars)	1993 ADDITIONS		INVESTMENT DECEMBER 31, 1993			Investment December 31, 1992		
	COST	%	COST	NET	%	Cost	Net	%
Exploration and production.....	$503,018	83	2,858,996	1,075,655*	70	2,350,687	659,231*	62
Refining.......................	66,364	11	484,043	221,455	14	419,297	175,881	16
Marketing......................	16,941	3	140,478	94,558	6	129,347	85,477	8
Transportation.................	3,580	-	61,708	34,082	2	58,899	33,751	3
Farm, timber, and real estate..	9,674	2	158,740	107,834	7	153,865	105,067	10
Corporate and other............	4,034	1	26,017	15,666	1	25,572	13,772	1
	$603,611	100	3,729,982	1,549,250	100	3,137,667	1,073,179	100

*Includes $18,021 in 1993 and $22,959 in 1992 related to administrative assets and support equipment.

Exploration and production additions in 1993 include expenditures for acquiring and/or developing an 11.26-percent interest in U.K. North Sea Block 16/17, $166,807,000; a 6.5-percent interest in the Hibernia oil field, offshore Newfoundland, $38,438,000; and a five-percent interest in the Syncrude project in northern Alberta, $109,005,000, of which $67,370,000 was financed by assuming directly related liabilities.

Capital leases, consisting of a fluid catalytic cracking unit in the U.K. and other refinery assets, were as follows at December 31, 1993 and 1992.

(Thousands of dollars)	1993	1992

Property, plant, and equipment	$ 57,748	58,838
Accumulated amortization	(34,701)	(32,515)
	$ 23,047	26,323

Long-term obligations on the lease of the fluid catalytic cracking unit have been paid. Future rental commitments on this equipment are not material.

The Company also leases land, service stations, and other facilities under operating leases. Future minimum rental commitments under noncancelable operating leases are not material.

Commitments for capital expenditures were approximately $274,000,000 at December 31, 1993. This includes $102,000,000 applicable to the Hibernia oil field, most of which will be financed with additional nonrecourse debt.

NOTE H -- FINANCING ARRANGEMENTS -- At December 31, 1993, Murphy Oil Corporation and certain wholly owned subsidiaries had lines of credit with banks for short-term borrowings at prime or various cost of funds rate options for $90,000,000 plus Cdn $28,000,000 (US $21,151,000 equivalent at December 31, 1993 currency exchange rate). At year-end, no amounts were borrowed under these agreements. These lines may be withdrawn by the banks at any time.

Certain wholly owned subsidiaries have a credit facility available until February 15, 1995, which provides for borrowings of U.S. and/or Canadian dollars up to an aggregate or equivalent of US $100,000,000 (Cdn $132,380,000 at December 31, 1993 currency exchange rate). The Company has options under the facility to select interest rates based on Canadian dollar prime rate or various cost of funds options. At December 31, 1993, US $27,100,000 was outstanding under this facility and classified as long-term nonrecourse debt of a subsidiary. (See Note I to the consolidated financial statements.)

Murphy Oil Corporation and certain wholly owned subsidiaries have a revolving and term loan agreement that provides for borrowings of U.S. and/or Canadian dollars up to an aggregate or equivalent of US $125,000,000, with the Canadian dollar component limited to Cdn $70,000,000. The agreement commenced April 1, 1992 and is comprised of a seven-year revolving period and a two-year term period. Commitment fees are due on the undrawn balance. The Company has options under the agreement to select interest rates based on certain banks' prime rates or various costs of funds options. At December 31, 1993, no amount was outstanding under this agreement.

Murphy Oil Corporation and certain wholly owned subsidiaries also have a short-term facility agreement that provides for borrowings of U.S. and/or Canadian dollars up to an aggregate or equivalent of US $25,000,000 (Cdn $33,095,000 at December 31, 1993 currency exchange rate). The facility, which may be renewed, is scheduled to expire March 28, 1994. Facility fees are due on the entire amount. The Company has options under the agreement to select interest rates based on certain costs of funds options offered by the lending bank. At December 31, 1993, no amount was borrowed under this agreement.

NOTE I -- LONG-TERM OBLIGATIONS

(Thousands of dollars)		
December 31	1993	1992
Notes payable		
Note payable to bank, 10.1%, due 2004	$ 20,000	20,000
Note payable to bank, face value of $3,333 at 7%, discounted to a 10% effective rate, due 1994	3,257	6,429
Other notes due 1994--2000	99	501
Subtotal	23,356	26,930
Capitalized lease obligations due 1994--2022, 6% and 8%	1,658	1,661
Nonrecourse debt of a subsidiary		
Guaranteed credit facility with bank, 3.75% to 3.875%, due 1995	27,100	--
Promissory note, 6.25%, due 1994--1998, payable in Canadian dollars	67,963	--
Subtotal	95,063	--
Total	120,077	28,591
Current maturities	(10,859)	(3,662)
Total long-term obligations	$109,218	24,929

Amounts becoming due for the four years after 1994 are: 1995, $7,565,000; 1996, $10,587,000; 1997, $13,610,000; and 1998, $28,696,000.

The nonrecourse guaranteed credit facility was incurred to finance 1993 expenditures for the Hibernia oil field, in which the Company owns a 6.5-percent interest. In connection with this acquisition, the government of Canada has provided, subject to certain conditions and limitations, an unconditional guarantee of repayment of amounts drawn under the facility to lenders possessing Participation Certificates issued by the guarantee's trustee. The Company's maximum eligible borrowing available under the guarantee is Cdn $154,885,000 (US $117,000,000 at December 31, 1993 currency exchange rate). The Company also received other commitments from the Canadian government, including grants and additional guarantees and loans. The amount guaranteed declines on a quarterly basis beginning the earlier of January 1, 2000 or two years after cumulative production reaches 25 million barrels; no guaranteed financing is available after January 1, 2016. A guarantee fee of .5 percent is payable annually in arrears to the Canadian government. The guaranteed credit facility is not reflected in the amounts becoming due in 1995, since the Company intends to refinance the debt.

Along with a cash payment, the 6.25-percent promissory note of Cdn $89,970,000 (US $67,963,000 at December 31, 1993 currency exchange rate), payable to the province of Alberta, was used to acquire a five-percent interest in the Syncrude project in northern Alberta. As collateral for the note, Murphy gave the province a debenture, which mortgages the acquired assets and the Company's share of production therefrom. The province's right to recover the principal and interest on the note is limited to the mortgaged property and funds available from that production. After year-end, the Company entered into forward foreign exchange contracts with matching amounts and maturities to purchase Canadian dollars payable under terms of the note.

NOTE J -- INCOME AND OTHER TAXES -- As discussed in Note B to the consolidated financial statements, the Company adopted SFAS No. 109, Accounting for Income Taxes, effective January 1, 1993 without restating prior years.

Total income tax expense for the year ended December 31, 1993 was $38,329,000. This amount included $46,829,000 allocated to income from continuing operations, partially offset by a benefit of $8,500,000 allocated to the cumulative effect of a change in accounting for postretirement benefits.

Income tax expense (benefit) attributable to income from continuing operations included the following.

(Thousands of dollars)	1993	1992	1991
Federal -- Current	$29,941*	17,213	6,717
Deferred	97	(6,565)	(5,619)
Noncurrent	4,977	(15,282)	15,487
Charge equivalent to income tax benefit of net operating loss carryforward	--	18,949	--
	35,015	14,315	16,585
State -- Current	5,368	4,703	7,016
Noncurrent	--	--	81
	5,368	4,703	7,097
Foreign -- Current	(32,029)	(12,561)	8,109
Deferred	28,154	(6,363)	(9,013)
Noncurrent	10,321	6,470	14,379
	6,446	(12,454)	13,475
	$46,829	6,564	37,157

*Net of benefits of $8,079 for net operating loss carryforward and $5,757 for alternative minimum tax credit.

Noncurrent taxes relate to petroleum revenue taxes payable to the U.K. government ($26,034,000 and $16,236,000 at December 31, 1993 and 1992 and classified in the Consolidated Balance Sheet as "Deferred Credits and Other Liabilities") and to matters not resolved with various taxing authorities. The significant components of deferred income tax expense attributable to income from continuing operations for the year ended December 31, 1993 were as follows.

(Thousands of dollars)	1993
Deferred tax expense (exclusive of the effects of components listed below on January 1, 1993 deferred tax assets and liabilities)	$18,270
Adjustments for enacted changes in tax laws and rates	190
Estimated net operating loss and tax credit carryforwards used or adjusted	9,791
Total deferred tax expense	$28,251

Prior to adoption of SFAS No. 109, deferred income taxes (benefits) resulted from recognizing income and expenses in different financial and tax reporting periods. Timing differences and the tax effect of each were as follows for the years ended December 31, 1992 and 1991.

(Thousands of dollars)	1992	1991
Unremitted earnings of foreign subsidiaries and other companies not permanently invested	$ (827)	(2,432)
Depreciation	1,018	1,164
Intangible development costs	(580)	(1,789)
Petroleum revenue tax	(1,827)	(4,354)
Product inventory valuation	(283)	3,055
Alternative minimum tax	(9,078)	(3,187)
Asset sales and writedowns	--	(7,860)
Other, net	(1,351)	771
	$(12,928)	(14,632)

A reconciliation of the U.S. statutory income tax rates to the Company's effective rates on income from continuing operations follows.

	1993	1992	1991
U.S. statutory income tax rates	35%	34%	34%
Subsidiary acquisition costs written off	--	--	88
Settlement of prior years' U.S. federal tax audits	--	(10)	(39)
Foreign income (losses) subject to foreign taxes at greater than U.S. statutory rates	7	(8)	5
State income taxes	3	--	16
Asset sales and write-downs	--	--	14
Amortization of fair value in excess of book value of properties acquired	--	7	11
Refund and settlement of foreign tax matters	(11)	(15)	--
Other, net	1	1	(5)
Effective income tax rates	35%	9%	124%

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 1993 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	1993
Deferred tax assets	
Property and leasehold costs..........................	$ 58,673
Reserves for dismantlement costs and major repairs....	51,305
Federal alternative minimum tax credit carryforward...	3,898
Postretirement and other employee benefits...........	16,290
Other deferred tax assets............................	46,816
Total gross deferred tax assets....................	176,982
Less valuation allowance.............................	(33,080)
Net deferred tax assets	143,902
Deferred tax liabilities	
Property, plant, and equipment.......................	(65,841)
Accumulated depreciation, depletion, and amortization.	(151,483)
Other deferred tax liabilities.......................	(25,887)
Total gross deferred tax liabilities	(243,211)
Net deferred tax liabilities	$ (99,309)

In management's judgment, the net deferred tax assets in the preceding table will more likely than not be realized as reductions in future taxable income or by utilizing available tax planning strategies. Uncertainties that may affect the ultimate realization of these assets include the future levels of crude oil and natural gas prices, product margins, operating costs, and tax rates. The Company will periodically review the likelihood of realizing these assets and adjust the valuation allowance as needed. The valuation allowance for deferred tax assets of $33,080,000 at December 31, 1993, has increased $6,410,000 (the same as the increase in certain deferred tax assets) from the amount determined as of January 1, 1993. Any subsequently recognized tax benefits relating to reductions in the valuation allowance will be reported as reductions of income tax expense assuming no offsetting change in the deferred tax asset.

The Company had undistributed earnings in certain foreign subsidiaries of $24,106,000 for which no deferred tax provision has been made because the earnings are considered permanently invested. Determination of the unrecognized tax liability on these earnings is not practicable. The amount of unrecognized deferred tax liability on undistributed earnings of jointly owned companies in the U.S. prior to January 1, 1993 is insignificant.

Income (loss) from continuing operations before income taxes and minority interest was generated from U.S. and foreign sources as follows.

(Thousands of dollars)	1993	1992	1991
United States.........	$84,563	60,105	(4,549)
Foreign...............	49,064	9,220	34,564

Income taxes are levied on the Company by the U.S. and several foreign countries. Because of differences in the tax structures of these countries, the relationship between income reported each year in the preceding table and the related U.S. and foreign income tax provisions is not meaningful.

Income tax returns are subject to audit by the Internal Revenue Service (IRS), which is currently examining the years 1987 and 1988, and tax authorities of other countries. In 1993, the Company recorded benefits to income of $14,409,000 from refund and settlement of U.K. income taxes. During 1992, the Company settled the final issue with the IRS related to the year 1979, resulting in a refund and a $21,500,000 benefit to income. Also during 1992, the Company settled income tax matters in the U.K. and Gabon that resulted in recording benefits to income of $12,186,000. In 1991, U.S. income tax refunds of $34,500,000 were recorded in income and represented the settlement of various issues from audits in prior years. A tentative settlement for the years 1981, 1982, 1983, 1984, and 1986 has been reached with the IRS subject to approval by the Joint Committee on Taxation. Based on this tentative settlement, adequate accruals have been made for all years.

At December 31, 1993, the Company had alternative minimum tax credit carryforwards of $3,898,000 available to reduce future U.S. federal income taxes, if any, over an indefinite period.

Taxes included in various costs and expenses on the Consolidated Statements of Income are as follows.

(Thousands of dollars)	1993	1992	1991
Payroll..	$ 5,729	5,502	5,580
Property.......................................	8,124	7,732	7,222
Production/severance...........................	4,175	4,094	3,997
Other..	3,604	1,959	1,808
Total charged to costs and expenses...........	21,632	19,287	18,607
Excise on petroleum products*..................	391,177	358,968	329,823
Total	$412,809	378,255	348,430

*Excluded from revenues and costs and expenses.

NOTE K -- STOCKHOLDERS' EQUITY -- A portion of the Company's operations is in foreign currencies. Cumulative translation gains and losses are included as a separate component of stockholders' equity as provided by SFAS No. 52, Foreign Currency Translation. At December 31, 1993, components of the net cumulative reduction of $1,514,000 were: a $14,112,000 reduction for Canadian dollars, mostly offset by additions of $10,849,000 for pounds sterling, $1,657,000 for Spanish pesetas, and $92,000 for Gabonese francs.

In 1992, stockholders adopted a Stock Incentive Plan that provides for annual awards of shares of the Company's Common Stock to executives and other key employees. The Executive Compensation Committee (Committee) is authorized to grant: (1) stock options (nonqualified or incentive), (2) stock appreciation rights (SAR), and (3) restricted stock awards. Total shares granted in a year may not exceed .5 percent of shares issued and outstanding at the end of the preceding year, and no more than 50 percent of the shares available each year may be granted as incentive stock options or restricted stock. If a grantee terminates for any reason other than normal retirement, total disability, or death, any outstanding stock options and SAR are canceled. If termination results from retirement, disability, or death, exercisable stock options and SAR may be exercised for the next two years if within the overall term. Other significant provisions of the Plan follow.

Stock options -- Option price for an incentive option is fair market value on date of grant; for a nonqualified option, the Committee may establish a price at no less than fair market on the date of grant. For each option, the Committee fixes the term, not to exceed 10 years from date of grant, and determines the earliest date the option may be exercised. Upon exercise, the grantee may pay the option price by using cash, surrender of shares, or a combination.

SAR -- SAR may be granted in conjunction with or independent of stock options; the Committee determines when SAR may be exercised and the price. When exercised, the grantee is paid the excess of fair market value of SAR shares exercised over the price set by the Committee. Upon exercise, rights under any related stock option terminate, and if a stock option is exercised, any related SAR terminate. Payment to the grantee may be made in cash, shares, or a combination as determined by the Committee. No SAR were awarded in 1993 or 1992.

Restricted stock awards -- Shares are awarded contingent upon the Company's achieving specific financial objectives at the end of a performance period. If the objectives are achieved, the grantee receives full ownership. If achievement is less than a threshold level, all shares are forfeited; if achievement is between the threshold and objectives, a percentage of the shares is forfeited; and if achievement is above objectives, additional shares may be awarded. The grantee may vote and receive dividends on the shares during the performance period and will be reimbursed by the Company for personal income tax liability on the stock, within limitations. Shares are subject to transfer restrictions and are forfeited if a grantee terminates during the performance period for any reason other than normal retirement, death, or full disability. If a grantee terminates for one of these reasons, vesting may occur at the end of the performance period on a pro rata number of shares based on months employed during the period. In 1992, 32,000 restricted shares were awarded. Subsequently, 4,489 shares have been forfeited, leaving 27,511 shares outstanding at December 31, 1993.

Options for 137,517 shares were outstanding and exercisable at December 31, 1993 under two other Murphy stock option plans that have terminated. These options, which will expire from 1994-2001 if not exercised, have an average exercise price of $37.26. At the discretion of the Committee, grantees may surrender these options for Common Stock or cash.

Changes in options outstanding under the Company's plans, excluding restricted stock awards, were as follows.

	Number of Shares	Average Price
Outstanding Jan. 1, 1991......	165,441	$32.04
Granted.......................	89,500	37.88
Conversion of subsidiary's options.....................	59,671	40.65
Exercised.....................	(250)	25.50
Surrendered...................	(9,037)	26.94
Expired.......................	(6,950)	42.92
Outstanding Dec. 31, 1991.....	298,375	35.42
Granted.......................	115,750	35.94
Exercised.....................	(800)	30.46
Surrendered...................	(52,015)	29.82
Expired.......................	(20,274)	45.25
Outstanding Dec. 31, 1992.....	341,036	35.87
Granted.......................	81,000	36.31
Surrendered...................	(45,019)	29.58
Outstanding Dec. 31, 1993	377,017	36.72
Exercisable Dec. 31, 1993	137,517	37.26

Cost of options reported in the preceding table is accrued over the vesting periods and adjusted for subsequent changes in fair market value of the shares. Charges against (credits to) income were $1,190,000 in 1993, $276,000 in 1992, and $(374,000) in 1991.

Changes in treasury stock for each of the three years ended December 31, 1993 are summarized as follows.

(Thousands of dollars)	Number of Shares	Amount
At January 1, 1991...........	3,845,845	$ 98,902
Purchased.....................	11	1
Exercised options for cash....	(250)	(6)
Issued shares for surrender of options........	(2,198)	(57)
Issued shares to effect exchange offer.............	(33,623)	(865)
At December 31, 1991.........	3,809,785	97,975
Purchased.....................	161,100	5,440
Exercised options for cash....	(800)	(20)
Issued shares for surrender of options........	(9,602)	(249)
Awarded restricted stock, net of forfeitures..........	(29,407)	(756)
At December 31, 1992.........	3,931,076	102,390
Purchased.....................	48,400	1,635
Issued shares for surrender of options........	(13,741)	(359)
Forfeited restricted stock....	1,896	49
At December 31, 1993	3,967,631	$103,715

NOTE L -- STOCKHOLDER RIGHTS PLAN -- The Company has a Stockholder Rights Plan, which provides that each Common stockholder at the close of business on December 20, 1989 and each certificate issued thereafter will receive a dividend of one Right for each share of the Company's Common Stock held. The Rights will expire on December 6, 1999, unless earlier redeemed or exchanged.

Rights will detach from the Common Stock and become exercisable following a specified period of time, subject to extension (Distribution Date), after the date of the first public announcement (Stock Acquisition Date) that a person or group of affiliated or associated persons (other than certain persons) has become the beneficial owner of 15 percent or more of the Company's Common Stock (an Acquiring Person). After the Distribution Date, each holder of a Right (excluding those Rights held by an Acquiring Person) will be entitled for each Right to:

. Purchase from the Company for $130.00, subject to adjustment (Purchase Price), .01 of a share of a new series of Participating Cumulative Preferred Stock, par value $100.00 per share.

. Purchase at the then-current Purchase Price Common Stock of the Company (in lieu of the new series of Preferred Stock) that has a value of twice the then-current Purchase Price.

. Purchase at the then-current Purchase Price Common Stock of the other party to a transaction that has a value of twice the then-current Purchase Price if the Company is acquired in a merger or other business combination in which the Company is not the surviving corporation or its Common Stock is changed into or exchanged for other security or assets or sells more than 50 percent of its assets or earning power.

Prior to the Distribution Date, the Board of Directors may redeem the Rights for $.01 each, subject to adjustment. Alternatively, after an Acquiring Person becomes the beneficial owner of at least 15 percent but less than 50 percent of the Company's Common Stock, the Board of Directors may exchange all or part of the Rights for shares of Common Stock at an exchange ratio, subject to adjustment, of one share of Common Stock for each Right.

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. However, 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 of the Rights is qualified in its entirety by, the Rights Agreement between the Company and Harris Trust Company of New York, as Rights Agent.

NOTE M -- FOREIGN CURRENCY TRANSACTIONS -- Net gains (losses) from foreign currency transactions were $10,000 in 1993, $(214,000) in 1992, and $420,000 in 1991.

NOTE N -- EMPLOYEE AND RETIREE BENEFITS
Retirement Plans -- The Company has defined benefit retirement plans that cover substantially all employees. Benefits are based on years of service and final-pay or career-average-pay formulas as defined by the plans. All plans are noncontributory. The Company also has supplemental plans that provide benefits to employees whose defined benefits under their retirement plan formula cannot be fully funded because of statutory limitations on the amount of benefits that may be paid from qualified plans.

Retirement expense (expense reduction) and its components for 1993, 1992, and 1991 are shown in the following table except for an expense reduction of $4,524,000 in 1992 that relates to a U.S. Employee Plan and an expense of $1,555,000 that relates to a Foreign Employee Plan. These amounts arose from Plan curtailments and special termination benefits that occurred primarily upon disposal of the contract drilling business segment. This net expense reduction is included in the 1992 Consolidated Statement of Income under Discontinued Operations as a component of "Gain on Disposal."

Special termination benefits were offered to eligible employees under the provisions of certain U.S. retirement plans in 1993 and 1991. Based on employees who accepted these benefits, actuarially determined costs were charged to retirement expense.

(Thousands of dollars)	1993	1992	1991
U.S. employee plans			
Service cost -- benefits earned during the year.....	$ 3,780	4,422	5,239
Interest accrued on benefits earned in prior years..	10,295	9,995	9,399
Actual return on plan assets........................	(8,564)	(15,996)	(23,034)
Net amortization and deferral.......................	(6,402)	(1,659)	9,909
Retirement expense (expense reduction)*............	(891)	(3,238)	1,513
Special termination benefits........................	1,316	--	681
Curtailment gain....................................	--	(1,091)	--
Net retirement expense (expense reduction)	$ 425	(4,329)	2,194

*Major assumptions were discount rates of 7.00% in 1993 and 7.25% in 1992 and 1991 and long-term rates of return on plan assets of 8.50% in 1993 and 9.00% in 1992 and 1991.

(Thousands of dollars)	1993	1992	1991
Foreign employee plans			
Service cost -- benefits earned during the year.....	$ 1,478	2,174	2,207
Interest accrued on benefits earned in prior years..	2,326	2,282	1,998
Actual return on plan assets........................	(4,466)	(2,458)	(5,875)
Net amortization and deferral.......................	1,463	(1,357)	2,492
Net retirement expense*	$ 801	641	822

*Major assumptions were discount rates of 7.50%-8.50% in each year. Assumed long-term rates of return on plan assets were 7.50%-8.50% in 1993 and 7.50%-9.00% in 1992 and 1991.

Amounts contributed to U.S. funded plans are actuarially determined and are at least the minimum required by the Employee Retirement Income Security Act of 1974. Amounts contributed to foreign plans are based on local laws. Two supplemental plans are unfunded, and projected benefit obligations exceeded assets in two funded plans in 1993 and 1992. Projected benefit obligations in excess of assets in these plans were $8,748,000 in 1993 and $7,338,000 in 1992; these amounts have been netted against assets in the following table, which sets forth the funded status of plans and amounts recognized in the Consolidated Balance Sheets.

(Thousands of dollars)	United States 1993	United States 1992	Foreign 1993	Foreign 1992
Present value of accumulated benefits based on years of service, applicable pay formula, and present pay levels				
Vested	$130,872	116,020	27,428	23,338
Nonvested	5,098	4,606	222	148
Accumulated benefit obligation(1)	135,970	120,626	27,650	23,486
Provision for future pay increases	20,671	21,332	4,918	6,136
Projected benefit obligation(1)	156,641	141,958	32,568	29,622
Plan assets -- at market value(2)	163,319	163,064	36,338	34,865
Plan assets in excess of projected benefit obligation	6,678	21,106	3,770	5,243
Unrecognized net asset from transition to SFAS 87(3)	(19,669)	(21,915)	(2,737)	(6,856)
Unrecognized net loss (gain) from unfavorable (favorable) actuarial experience	24,846	12,730	(5,699)	(1,774)
Unrecognized prior service cost	(130)	(131)	2,892	2,278
Prepaid (accrued) retirement cost	$ 11,725	11,790	(1,774)	(1,109)

(1) Major assumptions were discount rates of 6.50%-7.50% in 1993 and 7.00%-8.50% in 1992 and future pay rate increases of 5.00%-6.00% in 1993 and 5.00%-7.00% in 1992.
(2) Primarily includes listed stocks and bonds, government securities, U.S. agency bonds, corporate bonds, and group annuity contracts.
(3) Being amortized over periods of 15 to 19.7 years.

Thrift Plans -- Most employees of the Company in the U.S. and Canada may participate in thrift plans by allotting up to a specified percentage of their base pay. The Company makes matching contributions at a stated percentage of each employee's allotment based on length of participation in the plans. Aggregate Company contributions to these plans for 1993, 1992, and 1991 were $2,631,000, $2,502,000, and $2,996,000, respectively. Of the 1991 contribution, $793,000 was allocated to discontinued operations.

Postretirement Benefits -- The Company sponsors plans that provide comprehensive health care benefits (as a supplement to Medicare benefits for those eligible) and life insurance benefits for most U.S. retired employees. Retirees contribute the same amounts to the self-funded cost of health care benefits as do active employees, with the Company contributing the remainder. The Company pays premiums for life insurance coverage, which is arranged through an insurance company. The health care plan is funded on a pay-as-you-go basis. The Company has the right to modify the benefits and/or cost-sharing provisions. No postretirement benefits are provided by the Company for foreign employees.

Under SFAS No. 106, which was adopted January 1, 1993, the Company's postretirement expense in 1993 based on actuarial computations was $2,854,000; cash payments totaled $1,411,000 in 1993. The cash costs of these benefits in 1992 and 1991 were $1,295,000 and $1,608,000; amounts were expensed when paid. Components of the postretirement benefit expense for 1993 were as follows.

(Thousands of dollars)	Health Care	Life Insurance	Total
Service cost -- benefits earned during year	$ 581	23	604
Interest cost -- on accumulated postretirement benefit obligations	1,989	261	2,250
Postretirement benefit expense	$2,570	284	2,854

The following table summarizes the accrued obligation recorded in the Consolidated Balance Sheet at December 31, 1993, and classified as "Deferred Credits and Other Liabilities." Calculation of the amount of accumulated unfunded postretirement benefit obligations (APBO) was based on a 7.25-percent discount rate.

(Thousands of dollars)	Health Care	Life Insurance	Total
APBO			
Retirees	$14,229	2,857	17,086
Fully eligible active participants	3,095	361	3,456
Other active participants	13,115	586	13,701
Total unfunded APBO	30,439	3,804	34,243
Unrecognized obligations resulting from change in discount rate	(7,183)	(772)	(7,955)
Accrued APBO obligations	$23,256	3,032	26,288

For measurement purposes, health care inflation cost for 1993 was determined assuming an annual increase of 12 percent, gradually decreasing to a rate of six percent in 2003 and thereafter. An increase of one percent in the assumed health care cost trend in each year would increase the postretirement benefit expense by 12.8 percent and the APBO at December 31, 1993 by 16.8 percent.

NOTE O -- INCENTIVE COMPENSATION PLAN -- In 1992, the Board of Directors adopted an Incentive Compensation Plan that provides for annual cash awards to officers, directors, and key employees based on actual results for the year compared to measurable financial performance objectives established at the beginning of each year. The Plan is administered by the Executive Compensation Committee. Provisions of $1,732,000 and $1,500,000 were recorded in 1993 and 1992 in anticipation of future awards. A provision of $623,000 was recorded in 1991 under terms of a previous management incentive plan.

NOTE P -- FAIR VALUE OF FINANCIAL INSTRUMENTS -- The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value.

- Cash and cash equivalents, trade receivables, short-term debt, and trade payables -- The carrying amounts approximate fair value because of the short maturity of these instruments.
- Investments and noncurrent receivables -- Of the total reported, disclosure of fair value is not required on $29,733,000 of insurance receivables or on $3,002,000 of investments carried on an equity basis. The carrying amount of the remainder approximates fair value.
- Long-term obligations including current maturities -- The fair value is estimated based on current rates offered to the Company for debt of the same remaining maturities.
- Foreign currency contracts -- The fair value is estimated from quotes obtained from brokers.
- Financial guarantees and letters of credit -- The fair value is based on the estimated cost to terminate or otherwise settle these obligations with the counterparties.
- Crude oil price swaps -- The fair value is estimated from quotes for offsetting agreements with the same maturities.

Following is a summary of the estimated fair value at December 31, 1993 and 1992 of the Company's financial instruments other than those on which the carrying amount approximates fair value.

	1993			1992		
(Thousands of dollars)	Carrying Amount	Notional Amount	Estimated Fair Value	Carrying Amount	Notional Amount	Estimated Fair Value
Long-term obligations including current maturities	$120,077		125,172	28,591		31,693
Foreign currency contracts	--	2,639	2,639	--	6,750	6,596
Financial guarantees and letters of credit	--	83,888	83,888	--	92,494	92,494
Crude oil price swaps	--	2,400	2,400	--	--	--

NOTE Q -- CONCENTRATION OF CREDIT RISK -- The Company's cash equivalents consist primarily of U.S. Treasury Bills and securities issued by certain foreign governments. Trade accounts receivable balances arise primarily from sales of crude oil, natural gas, and petroleum products to a large number of customers who are geographically dispersed. The credit history and financial condition of potential customers are reviewed before credit is extended, security may be obtained then or later, routine follow-up evaluations are made, and an allowance for doubtful accounts is maintained, generally based upon a risk evaluation of specific customers. The Company also has certain off-balance-sheet financial instruments including foreign currency contracts, financial guarantees, letters of credit, and crude oil price swaps; the Company controls the credit risks on these instruments through credit approvals and monitoring procedures and believes such risks are minimal. Historically, the Company has not incurred any significant credit-related losses, and at December 31, 1993, the Company had no significant concentration of credit risk.

NOTE R -- SUPPLEMENTAL CASH FLOWS DISCLOSURES -- Cash income taxes paid, net of refunds, were $14,802,000, $(20,347,000), and $85,996,000 in 1993, 1992, and 1991. Interest paid, net of amounts capitalized, was $12,158,000, $14,714,000, and $19,856,000 in 1993, 1992, and 1991.

Noncash investing and financing activities excluded from the Consolidated Statements of Cash Flows were:

1993 -- Assumption of $67,370,000 of nonrecourse debt upon acquisition of a five-percent interest in the Syncrude project.

1991 -- Issuance of Common Stock in exchange for Common Stock of a subsidiary held by minority interests, $385,796,000, and a reduction of $10,545,000 previously shown as a long-term obligation as the result of settling litigation regarding an insurance subsidiary.

(Increases) decreases in noncash operating working capital for each of the three years ended December 31, 1993 were as follows.

(Thousands of dollars)	1993	1992	1991
Accounts receivable	$ 45,183	48,865	31,520
Inventories	(15,166)	(17,107)	8,126
Prepaid expenses	7,467	(23,813)	(4,853)
Deferred income taxes	(18,497)	--	--
Accounts payable and accrued liabilities	(5,922)	(41,409)	(92,409)
Current income tax liability	(12,647)	2,547	(38,820)
	$ 418	(30,917)	(96,436)

NOTE S -- CONTINGENCIES -- The Company's operations and earnings have been and may be affected by various forms of governmental action both in the U.S. 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 issuance of oil and gas or mineral leases; laws and regulations intended for the protection and/or remediation of the environment; promotion of safety; and laws and regulations affecting the Company's relationships with employees, suppliers, customers, shareholders, 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 which such actions may take, or the effect such actions may have on the Company.

DOE Matters -- On February 19, 1987, the U.S. Department of Energy (DOE) published a Proposed Remedial Order (PRO) alleging that the Company received approximately $13,367,000 for crude oil and/or related transportation charges in excess of amounts allowed under DOE regulations that were in effect from September 1973 through January 1981. The PRO sought restitution of this amount, plus interest of approximately $24,522,000 calculated to the date of the PRO.

On June 17, 1992, DOE's Office of Hearings and Appeals sustained the allegations of the PRO in their entirety and issued the Company a Remedial Order. The Company filed a Notice of Appeal to issuance of the Remedial Order and contested the material allegations in an appeal proceeding before the Federal Energy Regulatory Commission (FERC). On January 24, 1994, the presiding FERC administrative law judge issued a Decision and Proposed Order, which sustained the position of the Company on most of the material allegations in the proceeding. The record of the entire proceeding has been certified to the FERC, which will review the Decision and Proposed Order and affirm, reverse, or modify it. If the FERC should reverse the decision of its presiding administrative law judge, the Company will continue to vigorously defend its position on these issues. Under any circumstances, the Company believes that adequate accruals have been made.

Environmental Matters -- The Company's environmental contingencies are reviewed in Management's Discussion and Analysis under the section entitled "Environmental Obligations" on page 30.

Other Matters -- The Company and its subsidiaries are engaged in a number of other legal proceedings, all of which the Company considers routine and incidental to its business and none of which is material as defined. In the normal course of its business activities, 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, 1993, letters of credit outstanding amounted to $68,059,000. Contingent liability under a guaranty and pipeline throughput agreement was $15,829,000 at December 31, 1993.

NOTE T -- BUSINESS SEGMENTS -- Information about business segments and geographic operations is summarized in the following tables. Companies accounted for by the equity method are primarily engaged in the transportation of crude oil and petroleum products. Intracompany and affiliated company transfers are at market prices.

(Thousands of dollars)	1993	1992	1991
Revenues for the year			
Petroleum			
Exploration and production			
United States	$ 248,180	213,865	193,183
Canada	70,507	59,998	55,463
United Kingdom	53,567	56,548	68,358
Other international	17,186	28,267	40,247
	389,440	358,678	357,251
Refining, marketing, and transportation			
United States	940,990	968,398	937,269
Canada	29,444	29,237	22,683
Western Europe	272,699	285,978	329,550
	1,243,133	1,283,613	1,289,502
	1,632,573	1,642,291	1,646,753
Intrasegment transfers elimination	(65,041)	(69,660)	(85,182)
Total petroleum	1,567,532	1,572,631	1,561,571
Farm, timber, and real estate -- United States	69,136	58,810	46,982
Income from equity companies	973	2,180	1,174
Corporate and other	33,496	51,794	80,359
	$1,671,137	1,685,415	1,690,086

(Thousands of dollars)	1993(1)	1992(2)	1991
Operating income (loss) for the year			
Petroleum	$ 91,682	27,752	65,317
Farm, timber, and real estate	20,813	12,624	7,293
Income from equity companies	973	2,180	1,174
Corporate and other	22,359	41,594	(15,759)
	135,827	84,150	58,025
Deductions from (additions to) operating income			
Interest expense--net	2,200	14,825	28,010
Income taxes	46,829	6,564	37,157
Minority interest	--	--	2,465
(Gain) loss from discontinued operations, net of minority interest and income taxes	--	(23,855)	1,550
Extraordinary item	--	(18,949)	--
Cumulative effect of changes in accounting principles	(15,338)	--	--
	33,691	(21,415)	69,182
Net income (loss) for the year			
Petroleum			
Exploration and production			
United States	32,701	42,044	16,026
Canada	6,304	1,181	(20,708)
United Kingdom	17,931	1,692	1,778
Other international	(5,666)	(1,676)	(2,117)
	51,270	43,241	(5,021)
Refining, marketing, and transportation			
United States	7,246	(11,954)	20,924
Canada	8,628	9,377	6,835
Western Europe	11,625	1,895	15,585
	27,499	(682)	43,344
Total petroleum	78,769	42,559	38,323
Farm, timber, and real estate--United States	13,154	8,362	4,790
Corporate and other	(5,125)	30,789	(52,720)
Income (loss) from continuing operations	86,798	81,710	(9,607)
Gain (loss) from discontinued operations	--	23,855	(1,550)
Cumulative effect of changes in accounting principles	15,338	--	--
	$102,136	105,565	(11,157)

(1) As set forth in Note B to the consolidated financial statements, the effect on operating income of the petroleum segment from adoption of SFAS No. 109, Accounting for Income Taxes, was a reduction of $10,916, while the adoption of SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, had no significant effect on operating income.

(2) The tax benefit of utilizing a financial net operating loss carryforward of $18,949 in 1992, reported in the Consolidated Statement of Income as an extraordinary item, is allocated to the applicable segments in the net income (loss) summary.

(Thousands of dollars)	1993	1992	1991
Assets at year-end			
Petroleum			
Exploration and production			
United States	$ 461,087	426,231	402,699
Canada	343,880	162,888	184,159
United Kingdom	306,248	133,499	120,201
Other international	111,903	66,876	84,233
	1,223,118	789,494	791,292
Refining, marketing, and transportation			
United States	378,405	346,151	337,070
Canada	63,353	67,599	51,450
Western Europe	147,444	161,311	164,664
	589,202	575,061	553,184
Total petroleum	1,812,320	1,364,555	1,344,476
Farm, timber, and real estate--United States	150,261	141,784	134,590
Corporate and other	206,278	430,175	357,984
Net investment in discontinued operations	--	--	337,576
	$2,168,859	1,936,514	2,174,626
Additions to property, plant, and equipment for the year			
Petroleum			
Exploration and production			
United States	$ 71,883	56,038	72,264
Canada	172,838	15,988	11,203
United Kingdom	190,269	33,037	24,202
Other international	68,028	10,233	9,089
	503,018	115,296	116,758
Refining, marketing, and transportation			
United States	71,363	44,198	41,753
Canada	3,474	6,225	3,376
Western Europe	12,048	17,650	18,014
	86,885	68,073	63,143
Total petroleum	589,903	183,369	179,901
Farm, timber, and real estate--United States	9,674	6,017	2,858
Corporate and other	4,034	1,477	2,203
	$ 603,611	190,863	184,962

(Thousands of dollars)	1993	1992	1991
Depreciation, depletion, and amortization expense for the year			
Petroleum			
Exploration and production*			
United States	$ 97,196	81,935	80,591
Canada	21,062	19,058	43,582
United Kingdom	18,276	20,294	18,150
Other international	4,651	8,409	17,294
	141,185	129,696	159,617
Refining, marketing, and transportation			
United States	20,144	20,741	17,722
Canada	1,466	1,298	1,212
Western Europe	8,562	8,503	7,529
	30,172	30,542	26,463
Total petroleum	171,357	160,238	186,080
Farm, timber, and real estate -- United States	3,488	3,152	3,221
Corporate and other	1,368	1,432	3,818
	$176,213	164,822	193,119

*Includes amounts related to write-down of oil and gas properties in 1991 and excludes undeveloped lease amortization in all years.

SUPPLEMENTAL OIL AND GAS INFORMATION (unaudited)

The following schedules are presented in accordance with Statement of Financial Accounting Standards No. 69 (SFAS No. 69), Disclosures about Oil and Gas Producing Activities. The schedules 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 GAS RESERVES

Reserves of crude oil, condensate, and natural gas liquids and natural gas are estimated by Company engineers and 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. Quantities reported are considered reasonable, but they are subject to future revisions, some of which may be substantial, as additional information becomes available. Such additional knowledge may be gained as the result of: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes, and other economic factors.

Regulations published by the Securities and Exchange Commission define proved reserves as those volumes of crude oil, condensate, and 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 those volumes expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are those volumes expected to be recovered as a result of making additional investments by drilling new wells on acreage offsetting productive units, recompleting existing wells, and/or installing facilities to collect and transport volumes produced.

Crude oil and natural gas liquids reserves reported at December 31, 1993 under the heading "Other" are located in Spain and Gabon. Production quantities shown are net volumes withdrawn from reservoirs. These generally differ from quantities sold 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. Such differences were insignificant for crude oil and liquids. For natural gas, they amounted to approximately .9 billion cubic feet in 1993, .7 billion cubic feet in 1992, and 4.5 billion cubic feet in 1991.

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

Reserves of synthetic crude oil in Canada are attributable to the Syncrude project and are based on an estimated average gross production rate through the year 2018 of 183,500 barrels a day. Proved reserves will change if the future average production rate varies from the current estimated rate, which is based on the actual rate in 1993, or the operating permit is extended beyond 2018.

SCHEDULE 4 -- 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-percent annual discount factor and year-end (1993 and 1992) 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 calculated 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 at year-end 1993 used for this calculation were $12.53 a barrel for the United States, $11.04 for Canadian light, $6.90 for Canadian heavy, $9.63 for Hibernia, $12.93 for the United Kingdom, $7.71 for Ecuador, and $12.33 for Other. Average natural gas prices were $2.43 an MCF for the United States, $1.49 for Canada, $2.37 for the United Kingdom, and $2.24 for Spain.

Schedule 4 also presents a summary of the principal reasons for change in the standardized measure of discounted future net cash flows for each of the three years ended December 31, 1993.

SCHEDULE 6 -- RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

Results of operations from exploration and production activities by geographic area are reported on this schedule as if these activities were a separate corporate entity, rather than part of an integrated operation that will ultimately refine crude oil and sell refined products. Results of oil and gas producing activities should be considered in conjunction with the Company's overall performance.

SCHEDULE 1 -- ESTIMATED NET PROVED OIL RESERVES

(Millions of barrels)	Crude Oil, Condensate, and Natural Gas Liquids United States	Canada*	United Kingdom	Ecuador	Other	Total	Synthetic Oil-- Canada	Total
PROVED								
JANUARY 1, 1991..................	23.9	24.6	18.8	--	.3	67.6	--	67.6
Revisions of previous estimates..	.6	.4	(1.3)	--	1.0	.7	--	.7
Purchase of minerals in place....	.1	--	--	--	--	.1	--	.1
Extensions, discoveries, and other additions.................	3.1	.2	--	33.5	--	36.8	--	36.8
Production.......................	(4.9)	(3.4)	(2.8)	--	(1.1)	(12.2)	--	(12.2)
DECEMBER 31, 1991................	22.8	21.8	14.7	33.5	.2	93.0	--	93.0
Revisions of previous estimates..	1.9	1.7	.7	2.1	2.1	8.5	--	8.5
Purchases of minerals in place...	1.5	.2	--	--	--	1.7	--	1.7
Extensions, discoveries, and other additions................	1.9	2.5	--	--	--	4.4	--	4.4
Production.......................	(4.9)	(3.7)	(2.3)	--	(.5)	(11.4)	--	(11.4)
Sales of minerals in place.......	--	(.2)	--	--	--	(.2)	--	(.2)
DECEMBER 31, 1992................	23.2	22.3	13.1	35.6	1.8	96.0	--	96.0
REVISIONS OF PREVIOUS ESTIMATES..	.3	.8	(.5)	(2.0)	.7	(.7)	--	(.7)
PURCHASES OF MINERALS IN PLACE...	--	14.8	16.5	--	--	31.3	83.8	115.1
EXTENSIONS, DISCOVERIES, AND OTHER ADDITIONS................	1.5	3.2	--	--	--	4.7	--	4.7
PRODUCTION.......................	(5.0)	(4.6)	(2.4)	--	(.6)	(12.6)	--	(12.6)
SALES OF MINERALS IN PLACE.......	--	(.1)	--	--	--	(.1)	--	(.1)
DECEMBER 31, 1993................	20.0	36.4	26.7	33.6	1.9	118.6	83.8	202.4
PROVED DEVELOPED								
January 1, 1991..................	17.4	24.5	16.9	--	.2	59.0	--	59.0
December 31, 1991................	16.9	21.8	13.0	--	.2	51.9	--	51.9
December 31, 1992................	16.3	22.2	11.7	--	1.8	52.0	--	52.0
DECEMBER 31, 1993................	13.2	22.4	20.8	--	1.9	58.3	83.8	142.1

*Excludes 18.7 million barrels of crude oil to be added to proved reserves subsequent to start-up of production from the Hibernia oil field.

[GRAPH: ESTIMATED NET PROVED OIL RESERVES]

[GRAPH: ESTIMATED NET PROVED GAS RESERVES]

[GRAPH: NET HYDROCARBONS PRODUCTION]

SCHEDULE 2 -- ESTIMATED NET PROVED GAS RESERVES

(Billions of cubic feet)	United States	Canada	United Kingdom	Spain	Total
PROVED					
JANUARY 1, 1991	378.5	201.6	40.9	32.6	653.6
Revisions of previous estimates	4.2	11.3	3.6	(7.9)	11.2
Purchase of minerals in place	10.0	--	--	--	10.0
Extensions, discoveries, and other additions	63.1	1.4	--	--	64.5
Production	(59.6)	(9.4)	(3.4)	(8.1)	(80.5)
DECEMBER 31, 1991	396.2	204.9	41.1	16.6	658.8
Revisions of previous estimates	11.4	1.2	(1.0)	(5.4)	6.2
Purchases of minerals in place	91.9	3.4	--	--	95.3
Extensions, discoveries, and other additions	15.4	8.9	--	--	24.3
Production	(69.5)	(11.1)	(4.7)	(7.1)	(92.4)
Sales of minerals in place	--	(6.9)	--	--	(6.9)
DECEMBER 31, 1992	445.4	200.4	35.4	4.1	685.3
REVISIONS OF PREVIOUS ESTIMATES	48.0	(10.5)	.6	4.1	42.2
PURCHASES OF MINERALS IN PLACE	.3	.9	--	--	1.2
EXTENSIONS, DISCOVERIES, AND OTHER ADDITIONS	14.8	5.5	--	5.9	26.2
PRODUCTION	(79.5)	(13.4)	(4.8)	(3.5)	(101.2)
SALES OF MINERALS IN PLACE	--	(.2)	--	--	(.2)
DECEMBER 31, 1993	429.0	182.7	31.2	10.6	653.5
PROVED DEVELOPED					
January 1, 1991	213.4	142.5	24.1	24.3	404.3
December 31, 1991	230.5	172.5	25.5	16.6	445.1
December 31, 1992	217.0	164.0	32.3	4.1	417.4
DECEMBER 31, 1993	239.1	158.0	28.1	10.6	435.8

SCHEDULE 3 -- CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES

(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Other	Sub-total	Synthetic Oil--Canada	Total
DECEMBER 31, 1993								
Unproved oil and gas properties	$ 92.3	29.1	13.5	--	11.0	145.9	--	145.9
Proved oil and gas properties	1,377.9	457.1(1)	541.3	96.7	94.4	2,567.4	109.9	2,677.3
Gross capitalized costs	1,470.2	486.2	554.8	96.7	105.4	2,713.3	109.9	2,823.2
Accumulated depreciation, depletion, and amortization								
Unproved oil and gas properties	(50.6)	(15.8)	(.7)	--	(5.9)	(73.0)	--	(73.0)
Proved oil and gas properties(2)	(1,069.8)	(246.6)	(284.4)	--	(91.8)	(1,692.6)	--	(1,692.6)
Net capitalized costs	$ 349.8	223.8	269.7	96.7	7.7	947.7	109.9	1,057.6
DECEMBER 31, 1992								
Unproved oil and gas properties	$ 88.2	30.7	10.6	--	11.4	140.9	--	140.9
Proved oil and gas properties	1,298.9	363.2	363.8	27.5	114.9	2,168.3	--	2,168.3
Gross capitalized costs	1,387.1	393.9	374.4	27.5	126.3	2,309.2	--	2,309.2
Accumulated depreciation, depletion, and amortization								
Unproved oil and gas properties	(45.9)	(17.0)	(1.8)	--	(5.2)	(69.9)	--	(69.9)
Proved oil and gas properties(2)	(1,009.1)	(224.9)	(274.1)	--	(94.9)	(1,603.0)	--	(1,603.0)
Net capitalized costs	$ 332.1	152.0	98.5	27.5	26.2	636.3	--	636.3

(1) Includes Hibernia oil field, $37.4.
(2) Does not include reserve for dismantlement costs of $123.1 in 1993 and $112.7 in 1992.

SCHEDULE 4 -- 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	Other	Total
DECEMBER 31, 1993						
FUTURE CASH INFLOWS	$1,284.2	617.2	410.5	220.1	49.1	2,581.1
FUTURE PRODUCTION AND DEVELOPMENT COSTS	(505.7)	(466.4)	(248.0)	(220.1)	(49.0)	(1,489.2)
FUTURE INCOME TAXES	(217.5)	(67.9)	--	(3.0)	--	(288.4)
FUTURE NET CASH FLOWS	561.0	82.9	162.5	(3.0)	.1	803.5
10% ANNUAL DISCOUNT FOR ESTIMATED TIMING OF CASH FLOWS	(184.4)	(59.3)	(18.3)	(16.4)	4.2	(274.2)
STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS	$ 376.6	23.6	144.2	(19.4)	4.3	529.3
DECEMBER 31, 1992						
Future cash inflows	$1,377.8	554.3	296.4	428.0	38.0	2,694.5
Future production and development costs	(549.4)	(284.2)	(197.3)	(288.1)	(45.1)	(1,364.1)
Future income taxes	(235.5)	(97.4)	(28.8)	(29.2)	--	(390.9)
Future net cash flows	592.9	172.7	70.3	110.7	(7.1)	939.5
10% annual discount for estimated timing of cash flows	(212.5)	(64.4)	(16.5)	(85.9)	4.4	(374.9)
Standardized measure of discounted future net cash flows	$ 380.4	108.3	53.8	24.8	(2.7)	564.6

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

(Millions of dollars)	1993	1992	1991
Net changes in prices and costs	$(203.6)	106.0	(612.1)
Sales and transfers of oil and gas produced, net of production costs	(167.0)	(186.3)	(151.9)
Net change due to extensions, discoveries, and improved recovery	47.8	30.8	72.7
Net change due to purchases and sales of minerals in place	26.5	100.0	8.6
Development costs incurred during the period	150.6	58.7	52.7
Accretion of discount	82.2	60.2	115.5
Revisions of previous quantity estimates and other	(25.6)	50.2	(38.6)
Net change in income taxes	53.8	(92.1)	256.6
Net increase (decrease)	(35.3)	127.5	(296.5)
Standardized measure at January 1	564.6	437.1	733.6
Standardized measure at December 31	$529.3	564.6	437.1

(1) Excludes future net cash flows from synthetic oil.
(2) Excludes future net cash flows attributable to 18.7 million barrels of crude oil to be added to proved reserves subsequent to start-up of production from the Hibernia oil field.

SCHEDULE 5 -- COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION, AND DEVELOPMENT ACTIVITIES

	1993							
(Millions of dollars)	United States	Canada	United King-dom	Ecua-dor	Other	Sub-total	Synthetic Oil--Canada	Total
Property acquisition costs								
Unproved	$ 2.2	1.9	--	--	.3	4.4	--	4.4
Proved	1.4	5.0	144.3	--	--	150.7	109.0	259.7
Total acquisition costs	3.6	6.9	144.3	--	.3	155.1	109.0	264.1
Exploration costs	39.9	9.2	5.0	--	6.1	60.2	--	60.2
Development costs	49.4	52.7	42.9	67.7	--	212.7	--	212.7
Total capital expenditures	92.9	68.8	192.2	67.7	6.4	428.0	109.0	537.0
Charged to expense								
Dry hole expense	15.2	2.4	(.5)	--	4.4	21.5	--	21.5
Geophysical and other costs	5.8	2.6	2.5	--	1.6	12.5	--	12.5
Total charged to expense	21.0	5.0	2.0	--	6.0	34.0	--	34.0
Expenditures capitalized	$71.9	63.8	190.2	67.7	.4	394.0	109.0	503.0

	1992						1991					
(Millions of dollars)	United States	Canada	United King-dom	Ecua-dor	Other	Total	United States	Canada	United King-dom	Ecua-dor	Other	Total
Property acquisition costs												
Unproved	2.1	2.4	--	--	3.5	8.0	22.0	1.7	--	--	--	23.7
Proved	12.5	1.4	--	--	--	13.9	.3	--	--	--	--	.3
Total acquisition costs	14.6	3.8	--	--	3.5	21.9	22.3	1.7	--	--	--	24.0
Exploration costs	44.5	7.6	16.5	.1	10.7	79.4	45.1	7.4	15.1	--	10.7	78.3
Development costs	13.8	10.4	28.0	5.7	.8	58.7	17.3	8.3	22.2	4.0	.9	52.7
Total capital expenditures	72.9	21.8	44.5	5.8	15.0	160.0	84.7	17.4	37.3	4.0	11.6	155.0
Charged to expense												
Dry hole expense	11.3	2.7	8.6	--	7.3	29.9	6.9	2.7	9.4	--	2.3	21.3
Geophysical and other costs	5.6	3.1	2.9	.1	3.1	14.8	5.6	3.5	3.6	--	4.2	16.9
Total charged to expense	16.9	5.8	11.5	.1	10.4	44.7	12.5	6.2	13.0	--	6.5	38.2
Expenditures capitalized	56.0	16.0	33.0	5.7	4.6	115.3	72.2	11.2	24.3	4.0	5.1	116.8

SCHEDULE 6 -- RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

	1993							
(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Other	Subtotal	Synthetic Oil--Canada	Total
Revenues								
Crude oil and natural gas liquids								
Transfers to consolidated operations	$ 65.1	--	--	--	--	65.1	--	65.1
Sales to unaffiliated enterprises	16.6	54.1	38.4	--	8.0	117.1	--	117.1
Natural gas	165.8	16.4	11.0	--	9.2	202.4	--	202.4
Total oil and gas revenues	247.5	70.5	49.4	--	17.2	384.6	--	384.6
Settlement of windfall profit tax dispute	--	--	--	--	--	--	--	--
Other	.7	--	4.2	--	--	4.9	--	4.9
Total revenues	248.2	70.5	53.6	--	17.2	389.5	--	389.5
Costs and deductions								
Production costs	58.1	25.4	21.2	--	9.7	114.4	--	114.4
Exploration expenses	21.0	5.0	2.0	--	6.0	34.0	--	34.0
Undeveloped lease amortization	8.9	2.5	--	--	.7	12.1	--	12.1
Depreciation, depletion, and amortization	97.2	21.1	18.3	--	4.6	141.2	--	141.2
Write-down of certain properties	--	--	--	--	--	--	--	--
Minority interest and other deductions	9.2	4.8	3.3	.1	1.7	19.1	--	19.1
Total costs and deductions	194.4	58.8	44.8	.1	22.7	320.8	--	320.8
	53.8	11.7	8.8	(.1)	(5.5)	68.7	--	68.7
Income tax provision (benefit)	21.1	5.4	(9.1)	--	--	17.4	--	17.4
Results of operations*	$ 32.7	6.3	17.9	(.1)	(5.5)	51.3	--	51.3

	1992						1991					
(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Other	Total	United States	Canada	United Kingdom	Ecuador	Other	Total
Revenues												
Crude oil and natural gas liquids												
Transfers to consolidated operations	62.6	--	7.1	--	--	69.7	70.5	--	14.7	--	--	85.2
Sales to unaffiliated enterprises	28.3	48.8	33.9	--	10.0	121.0	24.2	44.9	41.9	--	17.0	128.0
Natural gas	122.0	11.2	13.4	--	18.3	164.9	89.8	10.6	10.2	--	23.2	133.8
Total oil and gas revenues	212.9	60.0	54.4	--	28.3	355.6	184.5	55.5	66.8	--	40.2	347.0
Settlement of windfall profit tax dispute	--	--	--	--	--	--	7.6	--	--	--	--	7.6
Other	1.0	--	2.1	--	--	3.1	1.1	--	1.6	--	--	2.7
Total revenues	213.9	60.0	56.5	--	28.3	358.7	193.2	55.5	68.4	--	40.2	357.3
Costs and deductions												
Production costs	49.1	23.3	25.8	--	11.8	110.0	48.1	24.5	24.7	--	8.9	106.2
Exploration expenses	16.9	5.8	11.5	.1	10.4	44.7	12.5	6.2	13.0	--	6.5	38.2
Undeveloped lease amortization	10.3	3.8	--	--	3.3	17.4	9.8	4.1	--	--	.2	14.1
Depreciation, depletion, and amortization	81.9	19.1	20.3	--	8.4	129.7	62.3	18.4	18.2	--	17.2	116.1
Write-down of certain properties	--	--	--	--	--	--	18.3	25.2	--	--	--	43.5
Minority interest and other deductions	13.5	5.1	5.1	.1	8.7	32.5	20.4	6.9	3.3	--	2.4	33.0
Total costs and deductions	171.7	57.1	62.7	.2	42.6	334.3	171.4	85.3	59.2	--	35.2	351.1

	42.2	2.9	(6.2)	(.2)	(14.3)	24.4	21.8	(29.8)	9.2	--	5.0	6.2
Income tax provision (benefit)..................	.2	1.7	(7.9)	--	(12.8)	(18.8)	5.8	(9.1)	7.4	--	7.1	11.2
Results of operations*.....	42.0	1.2	1.7	(.2)	(1.5)	43.2	16.0	(20.7)	1.8	--	(2.1)	(5.0)

*Excludes corporate overhead and interest.

STATISTICAL SUMMARY

[CAPTION]

	1993	1992	1991	1990	1989
EXPLORATION AND PRODUCTION					
Net crude oil and condensate production -- barrels a day					
United States	12,864	12,586	12,565	12,490	14,026
Canada -- light oil	4,546	3,972	4,305	4,674	4,658
heavy oil	7,449	5,366	4,744	4,921	4,319
United Kingdom	6,342	5,931	7,607	12,324	15,668
Other international	1,550	1,350	2,985	3,063	3,830
Net natural gas liquids production -- barrels a day					
United States	863	768	761	959	876
Canada	697	847	368	336	211
United Kingdom	--	--	160	271	464
Total	34,311	30,820	33,495	39,038	44,052
Net natural gas sold -- MCF a day					
United States	215,471	188,068	151,157	195,017	178,514
Canada	36,792	30,328	25,679	25,598	25,683
United Kingdom	13,074	12,802	9,354	3,716	--
Spain	9,571	19,402	22,207	22,977	27,776
Total	274,908	250,600	208,397	247,308	231,973
Total hydrocarbons produced -- equivalent barrels(1) a day	80,129	72,587	68,228	80,256	82,714
Weighted average sales prices(2)					
Crude oil and condensate -- dollars a barrel					
United States	$16.60	18.85	19.80	22.85	18.40
Canada(3) -- light oil	15.01	16.69	17.47	21.41	16.98
heavy oil	9.84	11.02	9.09	14.56	11.82
United Kingdom	16.63	18.86	19.86	21.50	18.22
Other international	14.14	18.85	16.57	17.70	15.94
Natural gas liquids -- dollars a barrel					
United States	13.36	14.71	15.65	15.32	10.97
Canada(3)	9.59	9.74	13.91	13.39	9.23
United Kingdom	--	--	15.35	13.86	8.85
Natural gas -- dollars an MCF					
United States	2.10	1.75	1.62	1.81	1.81
Canada(3)	1.22	1.01	1.12	1.24	1.17
United Kingdom(3)	2.31	2.86	3.00	2.94	--
Spain(3)	2.64	2.58	2.87	3.05	2.61
Net wells completed					
Oil wells -- United States	3.0	4.9	5.7	8.0	3.8
Canada	24.3	19.1	10.0	5.6	12.4
United Kingdom	.8	.3	.4	.5	.4
Other international	1.2	--	--	--	.2
Gas wells -- United States	8.5	5.1	9.4	10.7	9.2
Canada	4.1	2.4	1.4	10.6	1.7
United Kingdom	--	.5	.2	.4	.2
Other international	--	--	.3	--	--
Dry holes -- United States	6.5	5.2	5.9	10.5	8.3
Canada	6.9	2.6	6.9	6.2	4.6
United Kingdom	.1	1.0	1.1	.5	.4
Other international	.5	1.0	.3	--	1.1
Total	55.9	42.1	41.6	53.0	42.3
Net undeveloped acreage(4) -- thousands of acres	9,306	8,389	10,114	9,935	9,789

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

	1993	1992	1991	1990	1989
REFINING					
Crude capacity* of Company refineries -- barrels per stream day	167,400	167,400	167,400	167,400	147,400
Inputs/yields at Company refineries -- barrels a day					
Crude -- Meraux, Louisiana	78,732	80,842	75,059	74,962	70,204
Superior, Wisconsin	30,358	26,207	26,916	26,350	26,483
Milford Haven, Wales	27,991	24,245	25,969	22,628	25,594
Other feedstocks	10,350	12,857	11,310	13,243	11,959
Total inputs	147,431	144,151	139,254	137,183	134,240
Gasoline	66,460	67,710	60,491	62,469	64,629
Kerosine	16,024	13,338	15,662	15,885	15,824
Diesel and home heating oils	34,356	32,848	32,055	30,462	28,749
Residuals	16,441	18,474	17,237	16,155	13,596
Asphalt, LPG, and other	9,627	7,133	9,838	8,258	7,330
Fuel and loss	4,523	4,648	3,971	3,954	4,112
Total yields	147,431	144,151	139,254	137,183	134,240
Average cost of crude inputs to Company refineries -- dollars a barrel					
United States	$16.81	18.93	19.72	23.60	18.77
United Kingdom	17.44	19.84	20.74	24.06	18.71
MARKETING					
Products sold -- barrels a day					
United States -- Gasoline	61,577	59,128	50,075	52,922	53,636
Kerosine	11,682	10,855	12,156	12,964	12,775
Diesel and home heating oils	29,252	26,446	24,626	23,838	22,204
Residuals	11,812	12,339	11,926	10,823	9,208
Asphalt, LPG, and other	6,519	5,611	5,228	6,021	5,809
	120,842	114,379	104,011	106,568	103,632
Western Europe -- Gasoline	13,270	13,549	13,030	11,546	13,385
Kerosine	4,660	2,724	3,147	2,989	2,772
Diesel and home heating oils	7,525	7,112	7,593	6,262	6,833
Residuals	5,068	6,245	5,383	6,075	4,419
LPG and other	1,996	1,861	4,213	3,422	2,305
	32,519	31,491	33,366	30,294	29,714
Canada	234	172	129	76	39
Total products sold	153,595	146,042	137,506	136,938	133,385
Average gross margin on products sold -- dollars a barrel					
United States	$ .82	.48	1.59	1.49	1.59
Western Europe	3.08	2.67	3.52	3.72	2.78
Branded retail outlets*					
United States	606	643	622	643	644
Canada	8	7	6	4	2
United Kingdom	428	391	370	345	326
TRANSPORTATION					
Pipeline throughputs of crude -- barrels a day -- Canada	151,722	118,050	90,660	62,844	62,492

*At December 31.

	1993	1992	1991	1990	1989
FARM, TIMBER, AND REAL ESTATE					
Acres owned(1) -- Farmland	36,000	36,000	36,000	36,000	36,000
Timberland	341,000	342,000	341,000	341,000	344,000
Real estate	10,000	10,000	10,000	10,000	7,000
Acres harvested					
Cotton	4,839	4,518	4,099	2,919	1,672
Soybeans	14,863	12,798	15,584	14,993	12,169
Wheat	1,482	1,209	6,391	7,889	6,171
Corn	3,717	4,586	4,162	4,313	4,195
Rice	330	622	1,019	1,499	1,186
Yields per acre					
Cotton -- pounds	661	831	969	908	671
Soybeans -- bushels	24	39	30	23	25
Wheat -- bushels	40	59	21	36	29
Corn -- bushels	70	118	87	114	82
Rice -- bushels	107	107	112	107	115
Estimated standing pine timber inventories(1)					
Sawtimber -- thousand board feet -- Doyle scale (MBF-DS)	810,162	805,260	766,130	729,473	773,741
Pulpwood -- cords	962,563	940,477	988,790	972,089	1,002,330
Company-owned pine timber harvested					
Average sawtimber price(2) -- $ per MBF-DS	$ 310	274	202	211	166
Sawtimber -- MBF-DS	37,635	30,177	32,956	44,595	39,221
Pulpwood -- cords	12,536	8,767	15,038	10,004	21,654
Sawmills					
Production					
Finished lumber -- thousand board feet (MBF)	112,365	101,203	92,846	108,209	90,190
Pine chips -- tons	193,618	236,180	229,105	368,631	332,165
Annual capacity(1) -- MBF	122,600	100,100	100,100	120,600	120,600
Sales of finished lumber					
Thousand board feet (MBF)	115,136	105,619	95,024	108,204	92,279
Average price -- $ per MBF	$ 335	259	215	209	209
Average margin -- $ per MBF	82	34	13	2	9
Real estate					
Residential lots sold	147	120	98	53	28
Average price -- $ per lot	$ 48,200	53,200	49,700	74,000	92,500
Commercial acres sold	--	--	17	11	--
Average price -- $ per acre	$ --	--	32,700	37,000	--
STOCKHOLDER AND EMPLOYEE DATA					
Common shares outstanding(1) (thousands)	44,808	44,844	44,966	33,897	33,887
Number of stockholders of record(1)	5,265	6,522	5,826	4,584	4,953
Number of employees(1)	1,803	1,787	3,991	4,029	4,538
Average number of employees	1,787	1,857	4,001	4,213	4,428
Salaries, wages, and benefits (thousands)	$ 90,734	92,486	166,883	158,009	157,044

(1) At December 31.
(2) Includes intracompany transfers at market prices.

DIRECTORS

C. H. MURPHY JR. (1)
Chairman
Murphy Oil Corporation
El Dorado, Arkansas
Director since 1950

JACK W. McNUTT (1)
President and Chief Executive Officer
Murphy Oil Corporation
El Dorado, Arkansas
Director since 1981

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

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

JOHN W. DEMING (3,4)
Physician, Retired
Alexandria, Louisiana
Director since 1950

H. RODES HART (2,3,4)
Chairman and Chief Executive Officer
Franklin Industries, Inc.
Nashville, Tennessee
Director since 1975

VESTER T. HUGHES JR. (2,3,4)
Partner
Hughes & Luce
Dallas, Texas
Director since 1973

MICHAEL W. MURPHY (1,2,3,4)
President
Marmik Oil Company
El Dorado, Arkansas
Director since 1977

R. MADISON MURPHY (1)
Executive Vice President and Chief Financial and Administrative Officer
Murphy Oil Corporation
El Dorado, Arkansas
Director since 1993

WILLIAM C. NOLAN JR. (1,2,3,4)
Partner
Nolan and Alderson
El Dorado, Arkansas
Director since 1977

CAROLINE G. THEUS (2,3,4)
President
Inglewood Land and Development Company
Alexandria, Louisiana
Director since 1985

LORNE C. WEBSTER (2,3,4)
Chairman and Chief Executive Officer
Prenor Group Ltd.
Montreal, Quebec, Canada
Director since 1989

DIRECTORS EMERITI
GEORGE S. ISHIYAMA
WILLIAM C. NOLAN

Members of Board Committees
(1) Executive Committee.
(2) Audit Committee chaired by Mr. Hughes.
(3) Executive Compensation Committee chaired by Dr. Deming.
(4) Nominating Committee chaired by Dr. Deming.

OFFICERS

C. H. MURPHY JR.
Chairman

JACK W. McNUTT
President and Chief Executive Officer

CLAIBORNE P. DEMING
Executive Vice President and Chief Operating Officer

R. MADISON MURPHY

Executive Vice President and Chief Financial and Administrative Officer

STEVEN A. COSSE
Vice President and General Counsel

ODIE F. VAUGHAN
Treasurer

RONALD W. HERMAN
Controller

W. BAYLESS ROWE
Secretary

PRINCIPAL SUBSIDIARIES

MURPHY OIL USA, INC.
200 Peach Street
P. O. Box 7000
El Dorado, Arkansas 71731-7000
(501) 862-6411

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

HERBERT A. FOX JR.
President

STEVEN A. COSSE
Vice President and
General Counsel

ODIE F. VAUGHAN
Treasurer

RONALD W. HERMAN
Controller

W. BAYLESS ROWE
Secretary

MURPHY OIL COMPANY LTD.
2100--555--4th Avenue S.W.
P. O. Box 2721, Station M
Calgary, Alberta T2P 3Y3
Canada
(403) 294-8000

Engaged in crude oil and natural gas exploration and production; purchasing, transporting, and reselling of crude oil; and marketing of petroleum products in Canada.

G. CARL THOMPSON
President and Chief
Executive Officer

R. D. URQUHART
Vice President, Supply and
Transportation

W. GILL COLVIN
Controller

ROBERT A. LEHODEY
Secretary

ODIE F. VAUGHAN
Treasurer

MURPHY EASTERN OIL COMPANY
Winston House, Dollis Park,
Finchley
London N3 1HZ, England
081-349-9191

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 Western Europe.

GERALD MCAULLY
President

JAMES N. COPELAND
Vice President, Legal and
Personnel

ODIE F. VAUGHAN
Treasurer

W. BAYLESS ROWE
Secretary

DELTIC FARM & TIMBER CO., INC.
200 Peach Street
P. O. Box 7000
El Dorado, Arkansas 71731-7000
(501) 862-6411

Engaged in farming, timber and land management, lumber manufacturing and marketing, and real estate development in the United States.

RON L. PEARCE
President

ODIE F. VAUGHAN
Vice President and Treasurer

EMILY R. EVERS
Controller

JAMES E. BAINE
Secretary

MURPHY EXPLORATION &
PRODUCTION COMPANY
131 South Robertson Street
P. O. Box 61780
New Orleans, Louisiana 70161
(504) 561-2811

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

ENOCH L. DAWKINS
President

CLEFTON D. VAUGHAN
Vice President

STEPHEN C. HURLEY
Vice President, Oil and Gas
Exploration

G. L. GILREATH
Vice President, Administration

STEVEN A. COSSE
Vice President, General Counsel,
and Secretary

ODIE F. VAUGHAN
Vice President and Treasurer

BOBBY R. CAMPBELL
Controller

CORPORATE INFORMATION

CORPORATE OFFICES
200 Peach Street
P. O. Box 7000
El Dorado, Arkansas 71731-7000
(501) 862-6411

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

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 11, 1994, 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 under separate cover.

FORM 10-K
A copy of the Company's Annual Report on Form 10-K, filed with the Securities and Exchange Commission, may be obtained by writing to Murphy Oil Corporation, Controller's Department, P. O. Box 7000, El Dorado, Arkansas 71731-7000.

INQUIRIES
Inquiries regarding shareholder account matters should be addressed to the Secretary, Murphy Oil Corporation, P. O. Box 7000, El Dorado, Arkansas 71731-7000.

Members of the financial community should direct their inquiries to Ronald W. Herman, Controller, Murphy Oil Corporation, P. O. Box 7000, El Dorado, Arkansas 71731-7000, (501) 862-6411.

Printed in U.S.A. on recycled paper. [RECYCLING LOGO]

Appendix to Electronically Filed Exhibit 13
(1993 Annual Report to Security Holders, Which is Incorporated in This Form 10-K)
Providing a Narrative of Graphic and Image Material Appearing on Pages 4 Through 62 of Paper Format

Exhibit 13 Page No.	Map Narrative
5	Gulf of Mexico - The location and areal extent of acreage under lease by the Company in the Gulf of Mexico (offshore Texas, Louisiana, Mississippi, Alabama, and Florida) are shown. Additionally, each lease is categorized as either: (1) producing or producible; (2) discovery - commerciality to be determined/facilities to be installed; (3) unexplored, dry hole(s), or noncommercial shows; or (4) unexplored - acquired in 1993.
8	Canada - The location and areal extent of acreage under lease by the Company in British Columbia, Alberta, Saskatchewan, and Manitoba are shown. Additionally, specific areas of production are identified along with the type of production - natural gas, light oil, heavy oil, and oil sands.
9	Hibernia - The location of the Hibernia oil field in the North Atlantic east of Newfoundland, in which the Company holds an interest, is shown along with the location onshore Newfoundland where the production platform for this field is being constructed.
12	North Sea - The location and areal extent of producing and nonproducing acreage under license by the Company, primarily in the U.K. North Sea, is shown. Highlighted are a block where production began in late 1993 and two blocks where production is anticipated to begin in 1998 or 1999.
13	Ecuador - Depicted are the areal extent of acreage in which the Company has an interest in a risk-service contract for producing crude oil reserves discovered in prior years (production is expected to commence late in the first quarter of 1994), the location of support facilities, and the route for moving the crude into an existing transportation system. Also shown is adjoining acreage for which the Company had bid with others to obtain a license.
16	United States - The locations of the Company's two refineries are identified along with a depiction of the predominant routes and means of moving crude oil to the refineries, the routes and means of moving finished products from the refineries into market areas, the terminal facilities used to store and/or distribute products to wholesalers and consumers, and the areal extent of the Company's marketing territories in the Southeast and upper-Midwest.
18	United Kingdom - The location of the Company's refinery is identified along with a depiction of the route and means of moving crude oil to the refinery, the routes and means of moving finished products from the refinery into U.K. market areas, the terminal facilities used to store and/or distribute products to wholesalers and consumers, and the areal extent of the Company's marketing system.

Exhibit 13 Page No.	Map Narrative (Continued)
20	Canada - Pipelines - The location of major crude oil pipelines in southern Alberta and Saskatchewan are shown, including those that are operated and partially or wholly owned by the Company. Further detail is shown for Company-operated pipelines to indicate terminaling points.

	Picture Narrative
6	In the Gulf of Mexico, offshore Louisiana, a new production platform is shown being lifted from a barge for field installation. The platform provides permanent replacement facilities for producing crude oil and natural gas that were necessitated by destruction caused by Hurricane Andrew in August 1992.
6	In the Gulf of Mexico, another production platform and related equipment is shown being moved by barge to a new gas field. The platform and equipment were salvaged from a depleted field.
7	A bucketwheel reclaimer is shown at work at the Syncrude project in northern Alberta. This equipment scoops oil sands that have been placed in windrows onto a conveyor system, which transports the sands to a facility for further processing into light, sweet synthetic crude oil.
9	An areal view is shown at Bull Arm, Newfoundland, of the work site and progress made toward construction of a concrete Gravity Base Structure, which when completed and towed to the field site will be used to produce crude oil from the Hibernia oil field, offshore Newfoundland.
10	A drilling rig is shown on location at Plover Lake, southwestern Saskatchewan, as it horizontally drills a heavy oil well. This is representative of the level of activity that caused the Company's Canadian heavy oil production to increase 39 percent over the prior year.
11	A gas compression module is shown onshore in the U.K. This module was subsequently moved to the Ninian field in the U.K. North Sea and installed on a production platform to allow development of nearby marginally economic fields by utilizing (on a tariff basis accruing to the Company and its Ninian partners) Ninian's existing infrastructure.
14	Members of the Company's Board of Directors are shown observing archaeological efforts to identify artifacts in Ecuador near oil field development. The pipeline that will serve the development was rerouted to preserve the site.
17	A distillate desulfurizer unit at the Meraux, Louisiana, refinery is shown. This unit, which began operating in August 1993, can extract sulfur from up to 27,500 barrels a day of diesel fuel.

Exhibit 13 Page No.	Picture Narrative (Continued)
18	An employee of the Milford Haven, Wales, refinery is shown operating valves that control product flow within a maze of pipelines. Throughput volumes at the refinery set a new record for the year.
19	A recently acquired service station and convenience store is shown in Wales, near the Milford Haven refinery. The Company's strategy is to expand its sales in this area.
22	A view is shown looking across a golf course fairway and at adjacent houses, illustrating one of the many amenities of living at the Company's planned community in western Little Rock, Arkansas. Lot sales set a new record for the year, spurred by the lowest interest rate in more than 20 years.
22	Deltic's foresters are shown examining an increment core taken from a pine tree on a Company-owned timber tract in southern Arkansas. Examining the core helps determine the age and growth rate of the timber.
22	Pine logs are shown at the Ola, Arkansas, sawmill after removal of bark and just prior to being sawed into lumber by an upgraded system of saws that was installed in early 1993 to significantly improve lumber yields. This aided in meeting the high demand for lumber experienced throughout the year.

Graph Narrative

4 INCOME CONTRIBUTION* - EXPLORATION AND PRODUCTION
Scale - 0 to 75 (millions of dollars).

	1989	1990	1991	1992	1993
Income*	53.0	66.3	23.4	35.9	36.9

*Before unusual or infrequently occurring items.
This is a vertical bar graph with each year's value printed above the appropriate bar.

4 CAPITAL EXPENDITURES - EXPLORATION AND PRODUCTION
Scale - 0 to 600 (millions of dollars).

	1989	1990	1991	1992	1993
Proved Property Acquisitions (top)	6.8	3.5	.3	13.9	259.7
Development Costs	63.3	54.2	52.7	58.7	212.7
Exploration Costs (bottom)	65.3	89.0	102.0	87.4	64.6
Totals	135.4	146.7	155.0	160.0	537.0

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

Exhibit 13 Page No.	Graph Narrative (Continued)

6 CRUDE OIL AND NGL PRODUCTION
Scale - 0 to 50 (thousands of barrels a day).

	1989	1990	1991	1992	1993
Other International (top)	3.8	3.1	3.0	1.3	1.6
United Kingdom	16.2	12.6	7.8	5.9	6.3
Canada	9.2	9.9	9.4	10.2	12.7
United States (bottom)	14.9	13.4	13.3	13.4	13.7
Totals	44.1	39.0	33.5	30.8	34.3

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

6 NATURAL GAS SALES
Scale - 0 to 320 (millions of cubic feet a day).

	1989	1990	1991	1992	1993
Spain (top)	27.8	23.0	22.2	19.4	9.5
United Kingdom	--	3.7	9.3	12.8	13.1
Canada	25.7	25.6	25.7	30.3	36.8
United States (bottom)	178.5	195.0	151.2	188.1	215.5
Totals	232.0	247.3	208.4	250.6	274.9

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

15 INCOME CONTRIBUTION* -- REFINING, MARKETING, AND TRANSPORTATION
Scale - 0 to 50 (millions of dollars).

	1989	1990	1991	1992	1993
Income*	39.9	40.7	43.3	8.0	31.5

*Before unusual or infrequently occurring items.

This is a vertical bar graph with each year's value printed above the appropriate bar.

15 CAPITAL EXPENDITURES -- REFINING, MARKETING, AND TRANSPORTATION
Scale - 0 to 100 (millions of dollars).

	1989	1990	1991	1992	1993
Transportation (top)	1.4	3.3	3.3	6.0	3.6
Marketing	12.4	24.9	15.2	14.1	16.9
Refining (bottom)	14.4	30.9	44.6	48.0	66.4
Totals	28.2	59.1	63.1	68.1	86.9

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

Exhibit 13 Page No.	Graph Narrative (Continued)

15 REFINED PRODUCTS SOLD

Scale 0 to 175 (thousands of barrels a day).

	1989	1990	1991	1992	1993
Western Europe (top)	29.7	30.3	33.4	31.5	32.5
United States (bottom)	103.7	106.6	104.1	114.5	121.1
Totals	133.4	136.9	137.5	146.0	153.6

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

16 MERAUX REFINERY CRUDE CHARGE

Scale 0 to 100 (percentages of total).

	1991	1992	1993
Light Sour (top)	2.1	25.3	26.1
Heavy Sweet	29.3	23.5	29.0
Light Sweet (bottom)	68.6	51.2	44.9
Totals	100.0	100.0	100.0

This is a stacked vertical bar graph.

16 MERAUX REFINERY YIELDS

Scale 0 to 100 (percentages of total).

	1991	1992	1993
Fuel and Other (top)	5.8	5.5	6.4
Residuals	12.8	13.3	11.7
Middle Distillates	36.1	31.6	33.6
Gasoline (bottom)	45.3	49.6	48.3
Totals	100.0	100.0	100.0

This is a stacked vertical bar graph.

20 CANADIAN PIPELINE THROUGHPUTS

Scale 0 to 175 (thousands of barrels a day).

	1989	1990	1991	1992	1993
Throughputs	62.5	62.8	90.7	118.1	151.7

This is a vertical bar graph with each year's value printed above the appropriate bar.

21 INCOME CONTRIBUTION - FARM, TIMBER, AND REAL ESTATE

Scale 0 to 16 (millions of dollars).

	1989	1990	1991	1992	1993
Income--value plotted	3.30	6.16	4.79	8.36	13.15
--value printed	3.3	6.2	4.8	8.4	13.1

This is a vertical bar graph with each year's value printed above the appropriate bar.

Exhibit 13 Page No.	Graph Narrative (Continued)					
21	CAPITAL EXPENDITURES - FARM, TIMBER, AND REAL ESTATE Scale 0 to 14 (millions of dollars).					
		1989	1990	1991	1992	1993
	Capital Expenditures -- value plotted	11.20	10.38	2.86	6.02	9.67
	value printed	11.2	10.4	2.9	6.0	9.7

This is a vertical bar graph with each year's value printed above the appropriate bar.

21	SALES OF FINISHED LUMBER Scale 0 to 140 (millions of board feet).					
		1989	1990	1991	1992	1993
	Lumber Sales	92.3	108.2	95.0	105.6	115.1

This is a vertical bar graph with each year's value printed above the appropriate bar.

23	INCOME EXCLUDING UNUSUAL ITEMS Scale 0 to 120 (millions of dollars).					
		1989	1990	1991	1992	1993
	Income	78.8	96.1	57.7	54.9	76.4

This is a vertical bar graph with each year's value printed above the appropriate bar.

23	CASH PROVIDED BY CONTINUING OPERATIONS Scale 0 to 420 (millions of dollars).					
		1989	1990	1991	1992	1993
	Cash Provided	303.7	284.4	213.6	284.2	363.0

This is a vertical bar graph with each year's value printed above the appropriate bar.

23	STOCKHOLDERS' EQUITY AT YEAR-END Scale 0 to 1,400 (millions of dollars).					
		1989	1990	1991	1992	1993
	Stockholders' Equity	770	873	1,201	1,200	1,222

This is a vertical bar graph with each year's value printed above the appropriate bar.

Exhibit 13 Page No.	Graph Narrative (Continued)

24 INCOME CONTRIBUTION BY OPERATING FUNCTION*

Scale 0 to 100 (millions of dollars).

	1991	1992	1993
Farm, Timber, and Real Estate (top)	4.8	8.4	13.1
Refining, Marketing, and Transportation	43.3	8.0	31.5
Exploration and Production (bottom)	23.4	35.9	36.9
Totals	71.5	52.3	81.5

*Excludes Corporate and unusual or infrequently occurring items.

This is a stacked vertical bar graph with the value for each element printed within the element.

25 RANGE OF U.S. CRUDE OIL SALES PRICES

Scale 10 to 25 (dollars a barrel).

	1991	1992	1993
High monthly crude oil price (top of bar)	22.15	20.67	18.42
Average crude oil price (colored line)	19.80	18.85	16.60
Low monthly crude oil price (bottom of bar)	17.89	17.34	12.52

This is a floating vertical bar graph with a contrasting-color line between the top and bottom each year and highs printed above bars, averages printed above colored lines and lows printed below bars.

25 RANGE OF U.S. NATURAL GAS SALES PRICES

Scale 1.00 to 2.75 (dollars a thousand cubic feet).

	1991	1992	1993
High monthly natural gas price (top of bar)	1.97	2.60	2.51
Average natural gas price (colored line)	1.62	1.75	2.10
Low monthly natural gas price (bottom of bar)	1.28	1.16	1.63

This is a floating vertical bar graph with a contrasting-color line between the top and bottom each year and highs printed above bars, averages printed above colored lines, and lows printed below bars.

26 EXPLORATION EXPENSES

Scale 0 to 70 (millions of dollars).

	1991	1992	1993
Undeveloped Lease Amortization (top)	14.1	17.4	12.1
Geological, Geophysical, and Other Costs	16.9	14.8	12.5
Dry Hole Costs (bottom)	21.3	29.9	21.5
Totals	52.3	62.1	46.1

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

Exhibit 13 Page No.	Graph Narrative (Continued)

27 AVERAGE SALES PRICE OF U.S. REFINED PRODUCTS

Scale 0 to 28 (dollars a barrel).

	1991	1992	1993
Average Sales Price	24.84	23.25	21.44

This is a vertical bar graph with each year's value printed above the appropriate bar.

27 AVERAGE SAWMILL MARGIN

Scale 0 to 100 (dollars a thousand board feet).

	1991	1992	1993
Average Margin	13	34	82

This is a vertical bar graph with each year's value printed above the appropriate bar.

27 SELLING AND GENERAL EXPENSES

Scale 0 to 80 (millions of dollars).

	1991	1992	1993
Selling and General Expenses	71.8	72.9	65.2

This is a vertical bar graph with each year's value printed above the appropriate bar.

28 CAPITAL EXPENDITURES IN 1993

Scale 0 to 700 (millions of dollars).

	Percent
Other - $4 (top)	1
Farm, Timber, and Real Estate - $9.7	2
Refining, Marketing, and Transportation - $86.9	13
Exploration and Production - $537* (bottom)	84

*Includes proved property acquisitions of $259.7.

This is a stacked vertical bar graph with a line from each component to its respective percentage and "Total -- $637.6" printed below graph.

29 SOURCES OF CASH AND CASH EQUIVALENTS IN 1993

Scale 0 to 450 (millions of dollars).

	Percent
Sale of Property and Other - $8.2 (top)	2
Tax Settlements - $11.8	3
Nonrecourse Debt - $27.7	7
Operations - $351.2 (bottom)	88

This is a stacked vertical graph with a line from each component to its respective percentage and "Total -- $398.9" printed below graph.

Exhibit 13 Page No.	Graph Narrative (Continued)

29 USES OF CASH AND CASH EQUIVALENTS IN 1993

Scale 0 to 700 (millions of dollars).

	Percent
Debt Reduction and Other - $9.4 (top)	1
Dividends - $55.9	9
Cash Capital Expenditures - $570.2* (bottom)	90

*Includes cash component of proved property acquisitions - $192.3.

This is a stacked vertical bar graph with a line from each component to its respective percentage and "Total - $635.5" printed below graph.

55 ESTIMATED NET PROVED OIL RESERVES

Scale 0 to 240 (millions of barrels).

	1989	1990	1991	1992	1993
Other International (top)	5.9	.3	.2	1.8	1.9
Ecuador	-	-	33.5	35.6	33.6
United Kingdom	32.4	18.8	14.7	13.1	26.7
Canada*	23.8	24.6	21.8	22.3	120.2
United States (bottom)	25.1	23.9	22.8	23.2	20.0
Totals	87.2	67.6	93.0	96.0	202.4

*1993 includes synthetic oil - 83.8.

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

55 ESTIMATED NET PROVED GAS RESERVES

Scale 0 to 800 (billions of cubic feet).

	1989	1990	1991	1992	1993
Spain (top)	50.4	32.6	16.6	4.1	10.6
United Kingdom	42.3	40.9	41.1	35.4	31.2
Canada	181.4	201.6	204.9	200.4	182.7
United States (bottom)	374.0	378.5	396.2	445.4	429.0
Totals	648.1	653.6	658.8	685.3	653.5

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

55 NET HYDROCARBONS PRODUCTION

Scale 0 to 100 (thousands of barrels a day on an energy equivalent basis).

	1989	1990	1991	1992	1993
Other International (top)	8.5	6.9	6.7	4.6	3.2
United Kingdom	16.1	13.2	9.3	8.1	8.5
Canada	13.5	14.2	13.7	15.2	18.8
United States (bottom)	44.6	46.0	38.5	44.7	49.6
Totals	82.7	80.3	68.2	72.6	80.1

This is a stacked vertical bar graph with each year's total printed above the appropriate bar.

EXHIBIT 21

MURPHY OIL CORPORATION

PARENTS AND SUBSIDIARIES AS OF DECEMBER 31, 1993

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
MURPHY OIL CORPORATION (REGISTRANT)		
A. Deltic Farm & Timber Co., Inc.	Arkansas	100.0
1. Chenal Properties, Inc.	Arkansas	100.0
2. Deltic Timber Purchasers, Inc.	Arkansas	100.0
B. El Dorado Engineering Inc.	Delaware	100.0
1. El Dorado Contractors Inc.	Delaware	100.0
C. Murphy Eastern Oil Company	Delaware	100.0
D. 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. Odeco Drilling Limited	Bahamas	100.0
(1) Odeco Drilling (Africa) Limited S.A.	Panama	100.0
b. Rimrock Offshore Limited	Bahamas	100.0
3. El Dorado Exploration, S.A.	Delaware	100.0
4. Mentor Holding Corporation	Delaware	100.0
a. 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 Building Corporation	Delaware	100.0
7. Murphy Denmark Oil Company	Delaware	100.0
8. Murphy Ecuador Oil Company Ltd.	Bermuda	100.0
9. Murphy Equatorial Guinea Oil Company	Delaware	100.0
10. Murphy France Oil Company	Delaware	100.0
11. Murphy Ireland Oil Company	Delaware	100.0
12. Murphy Italy Oil Company	Delaware	100.0
13. Murphy Myanmar Oil Company S.A.	Panama	100.0
14. Murphy Overseas Ventures Inc.	Delaware	100.0
15. Murphy New Zealand Oil Company	Delaware	100.0
16. Murphy Pacific Rim, Ltd.	Bahamas	100.0
17. Murphy Pakistan Oil Company	Delaware	100.0
18. Murphy Peru Oil Company, S.A.	Panama	100.0
19. Murphy Somali Oil Company	Delaware	100.0
20. Murphy-Spain Oil Company	Delaware	100.0
21. Murphy Yemen Oil Company	Delaware	100.0
22. Norske Murphy Oil Company	Delaware	100.0
23. Norske Ocean Exploration Company	Delaware	100.0
24. Ocean Exploration Company	Delaware	100.0
25. Ocean France Oil Company	Delaware	100.0
26. Ocean Gabon Oil Company	Delaware	100.0
27. Ocean International Finance Corporation	Delaware	100.0
28. Ocean Spain Oil Company	Delaware	100.0
29. Ocean Western Oil Company	Delaware	100.0
30. Odeco Gabon Oil Company	Delaware	100.0
31. Odeco International Corporation	Panama	100.0

MURPHY OIL CORPORATION

PARENTS AND SUBSIDIARIES AS OF DECEMBER 31, 1993 (CONTD.)

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
MURPHY OIL CORPORATION (REGISTRANT) - Contd.		
D. Murphy Exploration & Production Company - Contd.		
32. Odeco Italy Oil Company	Delaware	100.0
33. Sub Sea Offshore (M) Sdn. Bhd.	Malaysia	50.0
E. Murphy Oil Company, Ltd.	Canada	100.0
1. 340236 Alberta Ltd.	Canada	100.0
2. Manito Pipelines Ltd.	Canada	52.5
3. Murcan Transportation Ltd.	Canada	100.0
4. Murphy Atlantic Offshore Oil Company Ltd.	Canada	100.0
5. Spur Oil Ltd.	Canada	100.0
6. Wascana Pipe Line Ltd.	Canada	100.0
F. Murphy Oil USA, Inc.	Delaware	100.0
1. Arkansas Oil Company	Delaware	100.0
2. Murphy Gas Gathering Inc.	Delaware	100.0
3. Murphy LOOP, Inc.	Delaware	100.0
4. Murphy Oil Trading Company (Eastern)	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. Murco Petroleum Limited	England	100.0
(1) Alnery No. 166 Ltd.	England	100.0
(2) European Petroleum Distributors Ltd.	England	100.0
(3) Murco Petroleum (Ireland) Ltd.	Ireland	100.0

EXHIBIT 23

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, and 2-86760) on Form S-8 of Murphy Oil Corporation of our reports dated March 4, 1994, relating to the consolidated balance sheets of Murphy Oil Corporation and Consolidated Subsidiaries as of December 31, 1993 and 1992, and the related consolidated statements of income, stockholders' equity, and cash flows and related financial statement schedules for each of the years in the three-year period ended December 31, 1993, which reports are included in the December 31, 1993, annual report on Form 10-K of Murphy Oil Corporation. Our report refers to changes in the methods of accounting for income taxes and postretirement benefits other than pensions in 1993.

KPMG PEAT MARWICK

Shreveport, Louisiana
March 29, 1994

UNDERTAKINGS

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

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.