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

FORM 8-K

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

Date of report (Date of earliest event reported): September 2, 2009

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

Delaware	1-8590	71-0361522
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

200 Peach Street
P.O. Box 7000, El Dorado, Arkansas 71731-7000
(Address of principal executive offices) (Zip Code)

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

Not applicable
(Former Name or Former Address, if Changed Since Last Report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ **Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)**

☐ **Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)**

☐ **Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))**

☐ **Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))**

Item 8.01. Other Events

Murphy Oil Corporation ("Murphy Oil", "Murphy", or the "Company") anticipates filing a Form S-3 registration statement with the U.S. Securities and Exchange Commission in the third quarter 2009 to place a shelf registration on file to be used, if needed, in the future to offer for sale bonds, notes, Common Stock, or other securities. The Company is filing this Current Report on Form 8-K to reflect a required accounting adjustment following the sale of the Company's Ecuador operations in March 2009 for the purpose of incorporation by reference of these statements in the Form S-3 registration statement. As discussed in Note C to the Consolidated Financial Statements included herein in Exhibit 99.3 and also in Note B of Murphy Oil's Form 10-Q for the three-month period ended March 31, 2009 and the six-month period ended June 30, 2009, as filed with the U.S. Securities and Exchange Commission on May 7, 2009 and August 7, 2009, respectively, the Company sold its operations in Ecuador on March 12, 2009. Due to the sale, all operating results for the Company's Ecuador operations are reported as discontinued operations. This Form 8-K includes restated consolidated financial statements for the three-year period ended December 31, 2008 to present all Ecuador operations as discontinued operations.

The Company has adjusted in Exhibits 99.1, 99.2 and 99.3 to this Current Report on Form 8-K the following information contained in its 2008 Form 10-K as filed on February 27, 2009 to reflect Ecuador operations as discontinued operations:

Item 6. Selected Financial Data

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Item 8. Financial Statements and Supplementary Data

Please note that other than the adjustments to present Ecuador operations as discontinued operations in this Current Report on Form 8-K, the Company has not otherwise updated or modified in this report the financial information or business discussion for activities or events occurring after February 27, 2009, the date the Company filed its 2008 Form 10-K. Therefore, this Current Report on Form 8-K should be read in conjunction with the 2008 Form 10-K and the Company's filings made with the Securities and Exchange Commission subsequent to the filing of the 2008 Form 10-K, including the Company's other Current Reports on Form 8-K and Quarterly Reports on Form 10-Q for the three-month period ended March 31, 2009 filed on May 7, 2009 and for the six-month period ended June 30, 2009 filed on August 7, 2009, which include among other matters, updated information for actual and expected 2009 production and legal matters.

Item 9.01. Financial Statements and Exhibits

Number	Description	
99.1	Item 6.	Selected Financial Data (adjusted to reflect presentation of results of the Company's Ecuador operations as discontinued operations).
99.2	Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations (adjusted to reflect presentation of results of the Company's Ecuador operations as discontinued operations).
99.3	Item 8.	Financial Statements and Supplementary Data (adjusted to reflect presentation of results of the Company's Ecuador operations as discontinued operations).

Signature

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

MURPHY OIL CORPORATION

By: /s/ John W. Eckart
John W. Eckart
Vice President and Controller

Date: September 2, 2009

Exhibit Index

99.1	Item 6.	Selected Financial Data (adjusted to reflect presentation of results of the Company's Ecuador operations as discontinued operations).
99.2	Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations (adjusted to reflect presentation of results of the Company's Ecuador operations as discontinued operations).
99.3	Item 8.	Financial Statements and Supplementary Data (adjusted to reflect presentation of results of the Company's Ecuador operations as discontinued operations).

As further discussed in Note C to the Company's consolidated financial statements (located in Exhibit 99.3 of this Current Report on Form 8-K), our consolidated financial statements for all periods presented herein have been adjusted to reflect the Company's Ecuador operations as discontinued operations.

Item 6. SELECTED FINANCIAL DATA

The financial data presented below for each of the five years ended December 31, 2008 should be read in conjunction with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data included as Exhibits 99.2 and 99.3, respectively, to this Current Report on Form 8-K.

(Thousands of dollars except per share data)	2008	2007	2006	2005	2004
Results of Operations for the Year					
Sales and other operating revenues	$ 27,360,625	18,297,637	14,156,666	11,563,453	8,268,344
Net cash provided by continuing operations	2,924,436	1,673,503	906,561	1,178,827	1,031,405
Income from continuing operations	1,744,749	739,080	603,050	808,107	493,832
Net income	1,739,986	766,529	644,669	854,742	705,128
Per Common share – diluted					
Income from continuing operations	9.08	3.87	3.19	4.30	2.64
Net income	9.06	4.01	3.41	4.55	3.77
Cash dividends per Common share	.875	.675	.525	.45	.425
Percentage return on					
Average stockholders' equity	29.1	16.8	16.8	28.0	30.7
Average borrowed and invested capital	24.4	13.9	14.4	23.5	21.6
Average total assets	15.1	8.5	9.3	14.6	13.4
Capital Expenditures for the Year					
Continuing operations					
Exploration and production	$ 1,928,346	1,740,327	1,046,463	1,067,068	826,631
Refining and marketing	426,156	572,458	173,400	202,401	134,706
Corporate and other	3,235	4,146	6,383	35,476	1,505
	2,357,737	2,316,931	1,226,246	1,304,945	962,842
Discontinued operations	6,949	40,416	36,293	24,886	21,616
	$ 2,364,686	2,357,347	1,262,539	1,329,831	984,458
Financial Condition at December 31					
Current ratio	1.51	1.37	1.61	1.43	1.35
Working capital	$ 958,818	777,530	795,986	551,938	424,372
Net property, plant and equipment	7,727,718	7,109,822	5,106,282	4,374,229	3,685,594
Total assets	11,149,098	10,535,849	7,483,161	6,410,396	5,498,903
Long-term debt	1,026,222	1,516,156	840,275	609,574	613,355
Stockholders' equity	6,278,945	5,066,174	4,121,273	3,522,070	2,702,632
Per share	32.92	26.70	21.97	18.94	14.68
Long-term debt – percent of capital employed	14.0	23.0	16.9	14.8	18.5

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

The following management’s discussion and analysis should be read in conjunction with the Company’s historical consolidated financial statements, located herein as Exhibit 99.3 to this Current Report on Form 8-K and in Item 8. Financial Statements and Supplementary Data of our 2008 Annual Report on Form 10-K. Any references to Notes in the following management’s discussion and analysis refers to the Notes to Consolidated Financial Statements located in Exhibit 99.3 to this Current Report on Form 8-K and in Item 8. Financial Statements and Supplementary Data of our 2008 Form 10-K. The results of operations reported and summarized below are not necessarily indicative of future operating results. This discussion also contains forward-looking statements that reflect our current views with respect to future events and financial performance. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of certain factors, such as those set forth in Item 1A. Risk Factors, which can be found in our 2008 Form 10-K.

As further discussed in Note C, our consolidated financial statements for the periods presented herein have been adjusted to reflect the results of the Company’s Ecuador operations as discontinued operations. The financial information contained in management’s discussion and analysis below reflects the adjustments described in Note C. Except as discussed in “Subsequent Events” below and in Note C, no other modifications or updates to these disclosures for events occurring after February 27, 2009, the date of the filing of our 2008 Form 10-K, have been made in this Current Report on Form 8-K.

Subsequent Events

On March 12, 2009, the Company sold its operations in Ecuador for net cash proceeds of $78.9 million, subject to post-closing adjustments. The acquiror also assumed certain tax and other liabilities associated with the Ecuador properties sold. The Ecuador properties sold included 20% interests in producing Block 16 and the nearby Tivacuno area. Ecuador operating results prior to the sale have been reported as discontinued operations for all periods presented. The consolidated financial statements for 2008 and prior years have been adjusted to conform to this presentation.

Overview

Murphy Oil Corporation is a worldwide oil and gas exploration and production company with refining and marketing operations in the United States and United Kingdom. A more detailed description of the Company’s significant assets can be found in Item 1 of the 2008 Form 10-K report filed with the Securities and Exchange Commission on February 27, 2009. As described in Note C to the consolidated financial statements, Murphy sold its interest in its Ecuador properties on March 12, 2009.

Murphy generates revenue primarily by selling oil and natural gas production and refined petroleum products to customers at hundreds of locations in the United States, Canada, the United Kingdom, Malaysia and other countries. The Company’s revenue is highly affected by the prices of oil, natural gas and refined petroleum products that it sells. Also, because crude oil is purchased by the Company for refinery feedstocks, natural gas is purchased for fuel at its refineries and oil production facilities, and gasoline is purchased to supply its retail gasoline stations in the U.S. that are primarily located at Walmart Supercenters, the purchase prices for these commodities also have a significant effect on the Company’s costs. In order to make a profit and generate cash in its exploration and production business, revenue generated from the sales of oil and natural gas produced must exceed the combined costs of producing these products, amortization of capital expenditures and expenses related to exploration and administration. Profits and generation of cash in the Company’s refining and marketing operations are dependent upon achieving adequate margins, which are determined by the sales prices for refined petroleum products less the costs of purchased refinery feedstocks and gasoline and expenses associated with manufacturing, transporting and marketing these products. Murphy also incurs certain costs for general company administration and for capital borrowed from lending institutions.

Worldwide oil and North American natural gas prices were significantly higher in 2008 than in 2007. The average price for a barrel of West Texas Intermediate crude oil in 2008 was $98.90, an increase of 37% compared to 2007. The NYMEX natural gas price in 2008 averaged $8.89 per million British Thermal Units (MMBTU), up 25% from 2007. Crude oil and natural gas prices generally rose during the first half of 2008 with oil prices reaching their high in July. Both crude oil and North American natural gas prices fell precipitously near the end of 2008 and remain soft in early 2009. Changes in the price of crude oil and natural gas have a significant impact on the profitability of the Company, especially the price of crude oil as oil represented approximately 93% of the total hydrocarbons produced on an energy equivalent basis by the Company in 2008. In 2009, the percentage of hydrocarbon production represented by oil is expected to decline to about 78% due to new natural gas fields at Kikeh and Block SK 309 in Malaysia and Tupper in British Columbia. If the prices for crude oil and natural gas remain weak in 2009 or beyond, the Company would expect this to have an unfavorable impact on operating profits for its exploration and production business. Such lower oil and gas prices could, but may not, have a favorable impact on the Company’s refining and marketing operating profits.

Results of Operations

The Company had net income in 2008 of $1.74 billion, $9.06 per diluted share, compared to net income in 2007 of $766.5 million, $4.01 per diluted share. In 2006 the Company’s net income was $644.7 million, $3.41 per diluted share. The significant increase in 2008 net income compared to 2007 was caused by higher earnings in the exploration and production operations, primarily due to higher sales prices for the Company’s oil and natural gas production, higher crude oil production volumes and gains on disposal of two assets in Canada. The earnings for the Company’s refining and marketing operations were an annual record in 2008 and improved from 2007, primarily in the U.K. and mostly caused by the December 2007 purchase of 70% of the Milford Haven, Wales refinery. The net cost of corporate activities not allocated to the operating segments was higher in 2008 than in 2007. The net income improvement in 2007 compared to 2006 primarily related to higher earnings generated by both the exploration and production and refining and marketing businesses, but partially offset by higher net costs for corporate activities. Further explanations of each of these variances are found in the following sections. Income from continuing operations was $1.74 billion, $9.08 per diluted share, in 2008; $739.1 million, $3.87 per diluted share, in 2007; and $603.1 million, $3.19 per diluted share, in 2006.

2008 vs. 2007 – Net income in 2008 was $1.74 billion, $9.06 per diluted share, compared to $766.5 million, $4.01 per diluted share, in 2007. The consolidated net income improvement of $973.5 million in 2008 was attributable to higher earnings in both exploration and production (E&P) and refining and marketing (R&M) operations. The net cost of corporate activities in 2008 was higher than in 2007, partially offsetting the improved results in E&P and R&M. Earnings from continuing E&P operations were markedly improved in 2008, increasing by $974.2 million compared to 2007, as this business benefited from both higher sales prices for oil and natural gas, higher sales volumes for crude oil and gains from asset dispositions. E&P earnings were unfavorably affected in 2008 compared to 2007 by lower sales volumes for natural gas and higher expenses for exploration, production, depreciation, depletion and administration. The R&M business generated record profits in 2008, increasing $108.1 million compared to 2007. The improvement was primarily due to refining profits generated in the U.K. in the current year following the acquisition of the remaining 70% of the Milford Haven, Wales, refinery in December 2007. R&M earnings in 2007 included an unfavorable impact in the U.K. from noncash inventory revaluations. Following the Milford Haven acquisition, the Company’s U.K. operations recorded an after-tax noncash last-in, first-out accounting charge of $59.5 million in 2007 to reduce the carrying value of crude oil and refined products inventory to beginning of year prices, which were significantly lower than at the end of the year. The net costs of corporate activities increased by $76.6 million in 2008 compared to 2007, with the cost increase mostly attributable to higher losses on transactions denominated in foreign currencies and higher net expenses for interest and administration. The foreign currency losses occurred because the U.S. dollar generally strengthened against other significant foreign currencies used in the Company’s business in 2008, especially compared to the British pound sterling. The higher net interest expense was mostly caused by lower interest capitalized to E&P development projects. The 2008 period included higher corporate administrative costs mostly due to higher expense for employee compensation and community and other support activities.

Sales and other operating revenues were $9.1 billion higher in 2008 than in 2007 mostly due to higher sales prices and sales volumes for gasoline and other refined products, higher sales prices and sales volumes for crude oil produced by the Company, and higher revenues from merchandise sales at retail gasoline stations. Sales prices for natural gas were higher in 2008 than 2007, but the favorable price variance was somewhat offset by lower natural gas sales volumes in the current year. Gain/(loss) on sales of assets in 2008 was $134.1 million higher than in 2007 and these realized pretax gains were primarily associated with the sales of its interests in Berkana Energy and the Lloydminster area heavy oil properties in Canada. Interest and other income was lower by $77.7 million in 2008 due primarily to greater losses on foreign currency exchange, which in the current year was mostly attributable to a generally stronger U.S. dollar compared to the British pound sterling. Crude oil and product purchases expense increased by $6.8 billion in 2008 compared to 2007 due to a combination of higher purchase prices and throughput volumes of crude oil and other feedstocks at the Company’s refineries, higher prices and volumes of refined petroleum products purchased for sale at retail gasoline stations, and higher levels of merchandise purchased for sale at the gasoline stations. The higher crude oil purchase volumes in 2008 were caused by a full year of operations at the Milford Haven, Wales refinery in 2008 following the December 2007 purchase of the remaining 70% interest. Operating expenses increased by $382.6 million in 2008 compared to 2007 and included higher refinery and retail station costs, and higher costs for oil field operations in Malaysia and synthetic oil operations at Syncrude. Refining costs increased due to both higher natural gas and other fuel costs and the full year of operations at Milford Haven following the 2007 acquisition. Exploration expenses were $141.6 million higher in 2008 than in 2007 and were primarily associated with higher leasehold amortization expenses at the Tupper area in British Columbia, more dry hole expense in Malaysia and Australia, and higher geophysical expenses in Suriname. Exploration expenses in 2007 included costs for settlement of two work commitments on leases formerly held on the Scotian Shelf offshore eastern Canada. Selling and general expenses were $0.2 million higher in 2008 than in 2007. Depreciation, depletion and amortization expense was $216.6 million higher in 2008 compared to 2007 due mostly to higher crude oil production volumes, but also due to higher barrel-equivalent unit rates for depreciation for virtually all E&P segments and higher depreciation for the Milford Haven, Wales refinery acquired in December 2007. Impairment of long-lived assets of $40.7 million in 2007 primarily related to closing 55 underperforming gasoline stations in the U.S. and Canada. Accretion of asset retirement obligations increased by $8.2 million in 2008 due to additional abandonment obligations incurred as additional Kikeh development wells were drilled during the year and higher estimated costs of future abandonment obligations at Syncrude. Net costs associated with hurricanes of $3.0 million in 2007 was due to a downward adjustment of anticipated insurance recoveries at the Meraux refinery following Hurricane Katrina based on updated loss limits communicated in 2007 by the Company’s primary property insurer. Interest expense incurred in 2008 was $1.1 million less than in 2007 due to lower average debt levels during 2008 compared to the prior year. The amount of interest costs capitalized to property, plant and equipment decreased by $18.4 million in 2008 due to lower levels of interest allocable to worldwide E&P development projects. Income tax expense was $623.7 million higher in 2008 than in 2007 and was mainly attributable to a higher level of pretax earnings. The effective income tax rate for consolidated earnings increased from 37.8% in 2007 to 38.1% in 2008. The tax rate in both years was higher than the U.S. federal statutory tax rate of 35.0% due to a combination of U.S. state income taxes, certain foreign tax rates that exceed the U.S. federal tax rate, and certain exploration and other expenses in foreign taxing jurisdictions for which no income tax benefit is currently being recognized because of the uncertain ability of the Company to obtain tax benefits for these costs in future years. Loss from discontinued operations of $4.8 million in 2008 declined by $32.2 million compared to 2007 primarily due to a higher revenue sharing with the government of Ecuador. During 2008, the government required a 99% share of Block 16 realized sales prices that exceeded a benchmark price that escalates with the monthly U.S. Consumer Price Index. This government revenue sharing increased from 50% above the benchmark price to 99% in October 2007. At year-end 2008, the benchmark oil price for Block 16 was approximately $23.36 per barrel. The average realized sales price after revenue sharing with the Ecuadorian government for Block 16 oil was $27.83 per barrel during 2008, a decrease of 24% from 2007. The higher revenue sharing led to unprofitable operating results in 2008 for operations in Ecuador. The Company sold the Ecuador properties in March 2009.

2007 vs. 2006 – Net income in 2007 was $766.5 million, $4.01 per diluted share, compared to $644.7 million, $3.41 per diluted share, in 2006. The improvement in consolidated net income in 2007 of $121.8 million compared to 2006 was primarily related to higher earnings in both major businesses – E&P and R&M. The net costs of corporate activities were higher in 2007 and partially offset the improved results in E&P and R&M. Earnings in the E&P business from continuing operations improved by $50.2 million in 2007 as this business benefited from higher oil sales prices, lower exploration expenses and lower income taxes in 2007 compared to 2006. E&P earnings were adversely affected in 2007 by lower sales volumes for oil and natural gas and slightly lower realized natural gas sales prices as well as higher expenses for production, depreciation, depletion and administration. The R&M business generated strong profits in 2007, increasing $95.1 million compared to 2006. The improvement was primarily due to higher U.S. refining margins in 2007 compared to 2006, a fully operational refinery at Meraux, Louisiana, during 2007, and lower hurricane repair expenses in 2007, but R&M earnings in 2007 included an unfavorable impact from noncash inventory revaluations in the U.K. The Meraux refinery was shut-down for repairs for the first five months of 2006 following significant damage caused by Hurricane Katrina in late August 2005. The Company incurred significant repair costs in 2006 at Meraux following Hurricane Katrina, certain of which were not recoverable through insurance policies. In the U.K., the Company acquired the remaining 70% interest in the Milford Haven, Wales, refinery in late 2007. Under the Company’s last-in, first-out accounting policy for inventory, an after-tax noncash charge of $59.5 million was recorded in 2007 to reduce the carrying value of crude oil and refined products inventory to beginning of year prices, which were significantly lower than at the end of the year. The net costs of corporate activities increased by $9.3 million in 2007 compared to 2006, with the cost increase mostly attributable to higher net interest expense and higher losses on transactions denominated in foreign currencies. The higher net interest expense was caused by higher average borrowing levels, partially offset by a higher level of interest costs capitalized to E&P development projects. The U.S. dollar generally weakened against other significant foreign currencies used in the Company’s business in 2007, especially compared to the Canadian dollar. The 2007 period included lower corporate administrative costs mostly due to higher expense in 2006 for an educational assistance contribution commitment.

Sales and other operating revenues were $4.1 billion higher in 2007 than in 2006 mostly due to higher sales volumes and sales prices for gasoline and other refined products, higher sales prices for crude oil produced by the Company, and higher sales volumes for merchandise at retail gasoline stations. Sales volumes for oil and natural gas were lower in 2007 than in 2006. Gain/(loss) on sales of assets in 2007 was $9.8 million unfavorable to 2006 as the Company had no major asset sales in 2007. Interest and other income was higher by $0.5 million in 2007 compared to 2006. Crude oil and product purchases expense increased by $3.7 billion in 2007 compared to 2006 due to a combination of higher purchase prices and throughput volumes of crude oil and other feedstocks at the Company's refineries, higher prices and volumes of refined petroleum products purchased for sale at retail gasoline stations, and higher levels of merchandise purchased for sale at the gasoline stations. The higher crude oil purchase volumes in 2007 were caused by the Meraux refinery being operational throughout 2007 following about five months of downtime for hurricane-related repairs in 2006. Operating expenses increased by $211.3 million in 2007 compared to 2006 and included higher refinery and retail station costs, higher workover and repair costs for Gulf of Mexico oil and gas fields, and higher costs for oil field operations in Malaysia and the U.K. and for Canadian synthetic oil operations at Syncrude. Exploration expenses were $15.0 million lower in 2007 than in 2006 primarily associated with less dry hole and geophysical expenses in Malaysia, but partially offset by higher costs in Canada for dry holes, geophysical, lease amortization and settlement of two work commitments on leases formerly held in the Scotian Shelf. Selling and general expenses were $0.9 million higher in 2007 than in 2006 as higher compensation, insurance and Berkana Energy administrative costs in 2007 were almost offset by lower costs associated with an educational assistance program called the El Dorado Promise. The Company acquired 80% of Berkana Energy in December 2006, and subsequently sold this investment in January 2008. Depreciation, depletion and amortization expense was $93.9 million higher in 2007 compared to 2006 due mostly to higher barrel-equivalent unit rates for depreciation for virtually all E&P segments and higher depreciation for the Meraux refinery and retail gasoline stations. Impairment of long-lived assets of $40.7 million in 2007 primarily related to closing 55 underperforming gasoline stations in the U.S. and Canada. Accretion of asset retirement obligations increased by $5.3 million in 2007 mostly due to additional abandonment obligations incurred as Kikeh development wells were drilled during the year, and higher anticipated future abandonment costs on existing wells in the U.S. Net costs associated with hurricanes was lower in 2007 by $106.2 million mostly due to uninsured repair costs incurred in 2006 at the Meraux refinery following Hurricane Katrina in 2005. The $3.0 million of hurricane expense recorded in 2007 related to a downward adjustment of anticipated insurance recoveries at the Meraux refinery based on updated projected loss limits announced by the Company's primary property insurer. Interest expense increased by $22.1 million in 2007 mostly associated with higher average debt levels during the year compared to 2006. The amount of interest costs capitalized to property, plant and equipment increased by $6.8 million in 2007 due to higher spending on E&P development projects in Malaysia, the U.S. and the Republic of the Congo. Income tax expense was $81.1 million higher in 2007 than in 2006 and was mainly attributable to higher pretax income levels. The effective income tax rate for consolidated earnings fell from 38.0% in 2006 to 37.8% in 2007. The tax rate in both years was higher than the U.S. federal statutory tax rate of 35.0% due to a combination of U.S. state income taxes, certain foreign tax rates that exceed the U.S. federal tax rate, and certain exploration and other expenses in foreign taxing jurisdictions for which no income tax benefit is currently being recognized because the ability to obtain tax benefits for these costs in future years is uncertain. The tax rates in both years benefited, however, from overall favorable effects of tax rate changes in foreign countries. Income from discontinued operations of $27.4 million in 2007 was $14.2 million less than in 2006 primarily due to higher revenue sharing with the Ecuadoran government. For most of 2007, the government received a 50% share of realized sales prices that exceeded a benchmark price that escalates with the monthly U.S. Consumer Price Index. However, in mid-October 2007, the government changed its share of such revenue from 50% to 99%. At year-end 2007, the benchmark oil price for Block 16 was approximately $23.28 per barrel. The 2007 average realized sales price after revenue sharing with the Ecuadorian government for Block 16 oil was $36.47 per barrel, an increase of 8% from 2006. The Company sold its properties in Ecuador in March 2009.

Segment Results – In the following table, the Company's results of operations for the three years ended December 31, 2008 are presented by segment. More detailed reviews of operating results for the Company's exploration and production and refining and marketing activities follow the table.

(Millions of dollars)	2008	2007	2006
Exploration and production – Continuing operations			
United States	$ 156.6	98.2	212.4
Canada	588.7	370.2	330.6
United Kingdom	73.8	47.6	60.7
Malaysia	865.3	148.2	(5.9)
Other	(81.6)	(35.6)	(19.4)
	1,602.8	628.6	578.4
Refining and marketing			
North America	227.9	230.4	77.5
United Kingdom	85.9	(24.7)	33.1
	313.8	205.7	110.6
Corporate and other	(171.8)	(95.2)	(85.9)
Income from continuing operations	1,744.8	739.1	603.1
Income (loss) from discontinued operations	(4.8)	27.4	41.6
Net income	$1,740.0	766.5	644.7

Exploration and Production – Earnings from exploration and production continuing operations were $1.60 billion in 2008, $628.6 million in 2007 and $578.4 million in 2006. E&P earnings improved $974.2 million in 2008 compared to 2007 with the significant increase primarily due to higher average realized sales prices for the Company's oil and natural gas production, higher crude oil production volumes and gains on disposals of Canadian assets. Results in 2007 were favorably impacted by income tax benefits associated with tax rate reductions in Canada. The 2008 results were unfavorably affected compared to 2007 by lower natural gas sales volumes and higher expenses for exploration, production, depreciation, depletion, administration and accretion of discounted abandonment liabilities. Crude oil sales volumes from continuing operations in 2008 were 49% higher than in 2007, compared with a 34% increase in crude oil production from continuing operations in 2008 compared to 2007. Crude oil sales volumes grew more than production in 2008 due to the timing of sale transactions as the Company had a lower inventory of unsold crude oil at year-end 2008 compared to a year earlier. The significant unsold crude oil inventory at year-end 2007 was mostly at Kikeh where sales volumes lagged production in late 2007 during the start-up phase of this field. During 2008, higher oil sales volumes in Malaysia attributable to higher production volumes at the Kikeh field were partially offset by lower oil sales volumes at most other producing areas. Lower U.S. crude oil sales volumes in 2008 were primarily due to reduced production volumes at several Gulf of Mexico fields following Hurricanes Gustav and Ike. Certain facilities owned by other companies downstream of our producing fields were down for repairs for an extended period of time in the fourth quarter 2008. Lower oil sales volumes in Canada were attributable to field decline at Hibernia, field decline and a higher royalty rate at Terra Nova, sale of the Lloydminster heavy oil property in Western Canada and more downtime at Syncrude. Lower crude oil sales volumes in the U.K. and at the West Patricia field, offshore Sarawak Malaysia, were mostly caused by production declines as these fields mature. Natural gas sales volumes were 9% lower in 2008 than 2007 and the reduction was mostly due to sale of Berkana Energy in January 2008. Additionally, several of the Company's Gulf of Mexico fields were either shut in or had curtailed gas production while downstream facilities owned by others were repaired following third quarter hurricanes. The Company's average realized oil sales price was 37% higher in 2008 than 2007, and the average North American natural gas sales price was 33% higher in 2008.

E&P earnings from continuing operations improved $50.2 million in 2007 compared to 2006 primarily due to higher average realized oil sales prices in the latter year for the Company's production. In addition, exploration expenses were lower by $14.9 million in 2007. Both years were favorably affected by income tax benefits associated with tax rate reductions in foreign countries. The 2007 results were unfavorably impacted compared to 2006 by lower oil and natural gas sales volumes, lower realized natural gas sales prices in North America and higher expenses for production, depreciation, depletion, administration and accretion of discounted abandonment liabilities. Crude oil sales volumes from continuing operations in 2007 were 2% lower than in 2006, despite a 4% increase in crude oil production from continuing operations in 2007 compared to 2006. The lower sales volumes were caused by the timing of sale transactions as the Company had a larger inventory of unsold crude oil at year-end 2007 compared to a year earlier. The 2007 increase in unsold crude oil inventory, which was primarily at the Kikeh field in Malaysia, returned to normal levels during 2008. During 2007, lower oil sales volumes in the U.S. were only partially offset by higher oil sales volumes in Malaysia and Canada. The lower sales volumes in the U.S. were due to field declines in the Gulf of Mexico. Higher oil sales volumes in Malaysia were mostly caused by start-up of the significant Kikeh field, offshore Sabah, in August 2007, partially offset by lower production at the West Patricia field, offshore Sarawak. Higher volumes in Canada were attributable to better production volumes at the Terra Nova field in the Jeanne d'Arc basin, offshore Newfoundland, which was shut-in for repairs for about six months in 2006. Natural gas sales volumes were 19% lower in 2007 than 2006 and the reduction was mostly due to field declines for maturing fields in the Gulf of Mexico and onshore south Louisiana as well as lower natural gas production at U.K. North Sea fields. The Company's average realized oil sales price was 21% higher in 2007 than 2006, while North American natural gas sales prices averaged 5% less in 2007 than in 2006.

The results of operations for oil and gas producing activities for each of the last three years are shown by major operating areas on pages F-39 and F-40 of this Form 8-K report. Average daily production and sales rates and weighted average sales prices are shown on page 10 which follows.

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

(Millions of dollars)	2008	2007	2006
United States			
Oil and gas liquids	$ 374.0	310.8	440.1
Natural gas	162.1	121.7	160.4
Canada			
Conventional oil and gas liquids	775.8	628.6	476.0
Natural gas	5.5	23.0	24.1
Synthetic oil	459.6	351.4	270.0
United Kingdom			
Oil and gas liquids	189.4	129.5	156.8
Natural gas	25.8	16.6	23.3
Malaysia			
Oil and gas liquids	1,985.6	436.0	219.6
Natural gas	0.1	—	—
Total oil and gas revenues	$ 3,977.9	2,017.6	1,770.3

The Company's total crude oil, condensate and natural gas liquids production (including discontinued operations in Ecuador) averaged 118,254 barrels per day in 2008, 91,522 barrels per day in 2007 and 87,817 barrels per day in 2006. Production of crude oil, condensate and natural gas liquids in 2008 increased by 26,732 barrels per day, or 29% compared to 2007, primarily due to continued ramp-up of the Kikeh field in Block K, offshore Sabah, Malaysia. This prolific field, which came on production in August 2007 produced 53,000 net barrels of oil per day for the full-year 2008 compared to 11,658 barrels per day in 2007. Light oil production in Canada declined from 596 barrels per day in 2007 to 46 barrels per day in 2008 due to sale of Berkana Energy in January 2008. Heavy oil production in the Western Canadian Sedimentary Basin (WCSB) fell from 11,524 barrels per day in 2007 to 8,484 barrels per day in 2008, due to sale of the Lloydminster property in 2008 and lower production volumes at the Seal field in Alberta. Oil production at Hibernia, offshore Newfoundland, was 8,542 barrels per day in 2008, up slightly from 8,314 barrels per day in 2007. Oil production decreased at Terra Nova, offshore Newfoundland, from 10,557 barrels per day in 2007 to 8,284 barrels per day in 2008. The 2008 reduction at Terra Nova was attributable to natural field decline plus a higher royalty rate. Syncrude production totaled 12,546 barrels per day in 2008 compared to 12,948 barrels per day in 2007, with the decline caused by more downtime for repairs and maintenance in the current year. Oil production declined in the U.S. from 12,989 barrels per day in 2007 to 10,668 barrels per day in 2008. The reduction was primarily at Gulf of Mexico fields where production was curtailed while awaiting repairs to downstream facilities owned by other companies that were damaged by third quarter hurricanes. Oil production in the U.K. was down from 5,281 barrels per day in 2007 to 4,869 barrels per day in 2008, with the reduction caused by declining production at the Company's primary fields in the North Sea. The West Patricia field, offshore Sarawak Malaysia, had net production of 4,403 barrels per day in 2008 after production levels of 8,709 barrels per day in 2007. West Patricia experienced declining production and a smaller portion of production was allocated to the Company's account under the production sharing contract. Oil production from discontinued operations in Ecuador totaled 7,412 barrels per day in 2008, compared to 8,946 barrels per day in 2007 due to a shut-down of the Block 16 development drilling program during 2008 following an arbitrary decision by the government to impose a 99% revenue sharing provision starting in late 2007 on all sales prices exceeding a benchmark price that averaged about $23.50 per barrel during the year.

Total production of crude oil, condensate and natural gas liquids (including discontinued operations in Ecuador) in 2007 increased by 3,705 barrels per day, or 4% compared to 2006, primarily due to start-up in August of the Kikeh field in Block K, offshore Sabah, Malaysia. This prolific field came on production only five years after discovery. Kikeh produced 11,658 barrels of oil per day for the full-year 2007. Oil production also increased in 2007 at Terra Nova, offshore eastern Canada, at Syncrude in Alberta, and in Ecuador. Oil volumes declined in 2007 at most other areas, including the U.S. and at Hibernia, West Patricia, the U.K. North Sea and the WCSB. Terra Nova produced throughout 2007 after being off-line for major equipment repairs for six months in 2006. Total production at Terra Nova was 10,557 barrels per day in 2007 and 3,900 barrels per day in 2006. Syncrude production totaled 12,948 barrels per day in 2007 compared to 11,701 barrels per day in 2006. The 2007 production increase at Syncrude was mostly attributable to a third coker unit that started up during 2006. Oil production declined in the U.S. from 21,112 barrels per day in 2006 to 12,989 barrels per day in 2007. The reduction was due to declines at various maturing fields in the Gulf of Mexico. Heavy oil production in the WCSB fell from 12,613 barrels per day in 2006 to 11,524 barrels per day in 2007, primarily due to a slower development drilling program for non-operated fields in Alberta. Oil production at Hibernia, offshore Newfoundland, was 8,314 barrels per day in 2007 down from 10,996 barrels per day in 2006 as the field experienced production decline during the year. Oil production in the U.K. was down from 7,146 barrels per day in 2006 to 5,281 barrels per day in 2007, with the reduction caused by declining production at the Company's primary fields in the North Sea. The West Patricia field, offshore Sarawak Malaysia, had net production of 8,709 barrels per day in 2007 after production levels of 11,298 barrels per day in 2006. West Patricia experienced declining production along with an increased government take under the production sharing contract. Oil production from discontinued operations in Ecuador totaled 8,946 barrels per day, up 338 barrels per day due to a more significant development drilling campaign in Block 16 in 2007.

Worldwide sales of natural gas were 55.5 million cubic feet (MMCF) per day in 2008, 61.1 million in 2007 and 75.3 million in 2006. Natural gas sales volumes in the United States increased 1% in 2008 and averaged 45.8 MMCF per day. The increase of 0.7 MMCF per day in 2008 would have been significantly higher but for the reduced gas production associated with hurricane damage to downstream facilities late in the year. Natural gas sales volumes in Canada averaged 1.9 MMCF per day in 2008, 81% lower than 2007. In January 2008, the Company sold Berkana Energy, formerly its largest gas producing asset in Canada. Natural gas sales volumes in the U.K. were up 7% in 2008 and averaged 6.4 MMCF per day. The U.K. gas sales volumes were mostly attributable to more gas volumes sold at the Mungo and Monan fields in the North Sea. Natural gas production commenced from the Kikeh field offshore Sabah Malaysia in December 2008 and sales volumes averaged 1.4 MMCF per day for the year.

Natural gas sales volumes in the United States fell 21% in 2007 and averaged 45.1 MMCF per day. The decline of 11.7 MMCF per day in 2007 was due to declines at various fields in the deepwater Gulf of Mexico and onshore South Louisiana. Natural gas sales volumes in 2007 increased 2% in Canada and averaged 9.9 MMCF per day. Natural gas sales volumes in the U.K. fell 31% in 2007 and averaged 6.0 MMCF per day. The lower U.K. gas sales volumes were attributable to lower associated gas volumes sold from two oil fields in the North Sea.

The Company's average worldwide realized crude oil, condensate and gas liquids sales price from continuing operations was $89.16 per barrel in 2008 compared to $65.15 per barrel in 2007. This was an increase of 37% in 2008. Oil prices began to plummet in the second half of 2008 and continued to display weakness in early 2009 as West Texas Intermediate crude oil prices averaged about $42 per barrel in January 2009. In the U.S., the Company realized an average price of $95.74 per barrel in 2008, up 46% from 2007. The average sales price in 2008 for heavy oil produced in Canada was $59.05 per barrel, 80% higher than in 2007. Hibernia and Terra Nova sales prices averaged $97.09 and $96.23 per barrel, respectively, during 2008, which were increases of 36% and 40%. Synthetic oil production sold for $100.10 per barrel, up 35% from a year earlier. U.K. oil prices increased 32% to $90.16 per barrel in 2008. In Malaysia, oil produced at the Kikeh field sold for 2% less in 2008 than in 2007, with an average of $89.36 per barrel for the just completed year. Kikeh came on stream in August 2007 and all sales during that year occurred in the fourth quarter when prices were at the strongest point during 2007. At the West Patricia field offshore Sarawak the 2008 average sales price of $72.04 per barrel was 22% above the 2007 average price.

The Company's average realized oil sales price from continuing operations was $65.15 per barrel in 2007, up 21% from the 2006 average of $53.93 per barrel. In the U.S., the Company realized an average price of $65.57 per barrel in 2007, up 14% from 2006. The 2007 average sales price for Canadian heavy oil production was $32.84 per barrel, 27% higher than in 2006. Hibernia and Terra Nova sales prices averaged $71.43 and $68.54 per barrel, respectively, during 2007, which were increases of 13% and 15%. Synthetic oil production sold for $74.35 per barrel in 2007, up 18% from a year earlier. U.K. oil prices increased 6% to $68.38 per barrel in 2007. In Malaysia, oil produced at the West Patricia field sold for 14% more in 2007 than in 2006, with an average of $59.05 for the year. The Kikeh field came on stream in August 2007 and all sales from this field occurred in the stronger price environment during the fourth quarter 2007 at an average of $90.84 per barrel.

The Company's natural gas sales prices rose in 2008 compared to 2007. The Company's average realized North American natural gas sales prices increased by 33% in 2008 to $9.54 per thousand cubic feet (MCF). In the U.K., the average 2008 natural gas price rose 46% to $10.98 per MCF.

The Company's average realized North American natural gas sales prices fell 5% in 2007 to $7.19 per MCF. In the U.K., the average 2007 natural gas price rose 3% to $7.54 per MCF.

Based on 2008 sales volumes and deducting taxes at marginal rates, each $1.00 per barrel and $0.10 per MCF fluctuation in prices would have affected 2008 earnings from exploration and production continuing operations by $26.6 million and $1.3 million, respectively. The effect of these price fluctuations on consolidated net income cannot be measured precisely because operating results of the Company's refining and marketing segments could be affected differently.

Production expenses from continuing operations were $611.5 million in 2008, $425.9 million in 2007 and $353.5 million in 2006. These amounts are shown by major operating area on pages F-39 and F-40 of this Form 8-K report. Costs per equivalent barrel during the last three years are shown in the following table.

(Dollars per equivalent barrel)	2008	2007	2006
United States	$ 10.01	10.75	7.10
Canada			
Excluding synthetic oil	9.44	8.77	9.36
Synthetic oil	41.08	30.56	28.23
United Kingdom	13.21	10.34	6.19
Malaysia	10.31	12.60	7.46
Worldwide – excluding synthetic oil	10.24	10.23	7.80

Production cost per equivalent barrel decreased in the U.S. in 2008 compared to 2007 due to lower costs incurred for workovers and repairs at fields in the Gulf of Mexico. U.S. per-barrel equivalent costs were higher in 2007 versus 2006 mostly due to higher workover and field repairs and lower production volumes. The per-unit costs for Canadian conventional oil and gas operations, excluding Syncrude, were higher in 2008 than 2007 mostly due to lower production levels. The cost for conventional oil in Canada was lower in 2007 than 2006 primarily due to higher production levels and lower repair costs at Terra Nova in 2007. Terra Nova was shut-in for major repairs for six months in 2006. Higher production costs per barrel for Canadian synthetic oil operations in 2008 were due to additional costs for fuel and repairs and lower production levels. The increased Syncrude cost in 2007 was primarily due to a higher net profit royalty rate and a higher foreign exchange rate. The average cost per barrel in the U.K. in 2008 versus 2007 was caused by lower overall production levels and higher repair costs. The higher average U.K. cost per barrel in 2007 was mostly due to higher maintenance costs, lower oil production at the North Sea fields and a higher foreign exchange rate. The lower average cost per barrel in Malaysia in 2008 compared to 2007 was attributable to higher production at Kikeh where unit costs per equivalent barrel are lower than at West Patricia. The higher per-unit cost in Malaysia in 2007 was due to the start-up phase for Kikeh oil and a lower production level for West Patricia compared to 2006.

Exploration expenses from continuing operations for each of the last three years are shown in total in the following table, and amounts are reported by major operating area on pages F-39 and F-40 on this Form 8-K report. Certain of the expenses are included in the capital expenditures total for exploration and production activities.

(Millions of dollars)	2008	2007	2006
Dry holes	$ 129.5	66.8	109.6
Geological and geophysical	85.2	67.7	73.1
Other	17.7	35.1	12.5
	232.4	169.6	195.2
Undeveloped lease amortization	112.0	33.2	22.5
Total exploration expenses	$ 344.4	202.8	217.7

Dry hole expense was $62.7 million more in 2008 than in 2007 and was attributable to more exploration drilling capital expenditures in 2008. With mostly new E&P management in 2007, much of that year was spent reevaluating the Company's worldwide exploration drilling prospects. The higher costs for dry holes in 2008 was mostly in the offshore waters of Malaysia and Western Australia. Dry holes expense was $42.8 million less in 2007 than 2006 primarily due to a lower level of exploration drilling activity in 2007. Geological and geophysical (G&G) expenses were $17.5 million higher in 2008 mostly due to a 3D seismic program at Block 37, offshore Suriname, and more seismic activities in the Tupper area in British Columbia. G&G expenses were $5.4 million less in 2007 than 2006 primarily due to lower spending in Malaysia for 3D seismic for Blocks SK 311 and H and lower geophysical analyses on PM Blocks 311/312. The lower Malaysian costs were partially offset by higher seismic costs in 2007 in the Gulf of Mexico and offshore Australia, and higher geophysical studies offshore the Republic of the Congo. Other exploration expenses in 2008 were $17.4 million lower than 2007 mostly due to a $21.9 million settlement in 2007 for unfulfilled work commitments on two expiring Scotian Shelf leases, offshore eastern Canada. Other exploration expenses in 2007 were $22.6 million higher than in 2006 also due to the Scotian Shelf work commitment settlement. Undeveloped leasehold amortization expense rose $78.8 million in 2008 compared to 2007, after an increase of $10.7 million in 2007 compared to 2006, primarily due to amortization of undeveloped land acquisition costs at the Tupper property in northeast British Columbia, where the Company has aggressively added undeveloped acreage over the last two years.

A $2.6 million charge in the exploration and production business for asset impairment in 2007 related to write-down of an unused E&P administrative office to estimated fair value.

Expense of $1.9 million was incurred in 2006 in the Company's exploration and production operations for uninsured costs to repair damages and to recognize associated higher insurance costs caused by Hurricanes Katrina and Rita in the Gulf of Mexico.

Depreciation, depletion and amortization expense from exploration and production continuing operations totaled $527.8 million in 2008, $337.6 million in 2007 and $269.7 million in 2006. The increase of $190.2 million in 2008 expense compared to 2007 was mostly caused by a much higher production level at the Kikeh field, offshore Sabah, Malaysia. The $67.9 million increase in 2007 compared to 2006 was caused by generally higher per-unit rates for development capital, the start-up of the Kikeh field, and an increase in foreign exchange rates in Canada and the U.K. The Company continues to experience high drilling and related costs caused by a strong demand for such services.

The exploration and production business recorded expenses of $23.5 million in 2008, $16.1 million in 2007 and $10.8 million in 2006 for accretion on discounted abandonment liabilities. Because the abandonment liability is carried on the balance sheet at a discounted fair value, accretion must be recorded annually so that the liability will be recorded at full value at the projected time of abandonment. The increase in accretion costs in 2008 was associated with higher estimated abandonment costs at Syncrude and additional development wells drilled at the Kikeh field. The higher accretion costs in 2007 were mostly related to higher estimated future abandonment costs for facilities and wells in the Gulf of Mexico and future abandonment obligations related to Kikeh development wells drilled in 2007.

The effective income tax rate for exploration and production continuing operations was 37.4% in 2008, 34.2% in 2007 and 35.8% in 2006. The effective tax rate was higher in 2008 than the previous two years as both 2007 and 2006 included net tax benefits from enacted changes in foreign tax rates. Canada lowered federal tax rates in both 2007 and 2006, and in 2006 the Canadian provinces of Alberta and Saskatchewan also reduced tax rates. The net benefit from these Canadian tax rate reductions, which effectively reduced recorded deferred tax liabilities was $38.7 million in 2007 and $37.5 million in 2006. The 2008 effective tax rate exceeded the U.S. statutory tax rate due to higher overall foreign tax rates and exploration activities in areas where current tax relief is not available. The effective tax rate in 2007 was slightly below the U.S. statutory tax rate of 35% primarily due to the enacted Canadian Federal tax rate reduction during the year. The 2007 effective tax rate was lower than in 2006 mostly due to a deferred tax expense in 2006 related to a 10% increase in U.K. tax rates on oil and gas profits. A $4.4 million U.S. tax benefit was realized in 2007 for a charitable building donation. Also in 2007, the Company incurred lower exploration and other expenses in tax jurisdictions where tax relief is currently not available. Tax jurisdictions with no current tax benefit on expenses primarily include non-revenue generating areas in Malaysia, the Republic of the Congo, Suriname, Australia and Indonesia. Each main exploration area in Malaysia is currently considered a distinct taxable entity and expenses in certain areas may not be used to offset revenues generated in other areas. No tax benefits have thus far been recognized for costs incurred for Blocks H, P, L and M, offshore Sabah, and Blocks PM 311/312, offshore Peninsula Malaysia. The 2006 effective tax rate was only slightly higher than the U.S. statutory tax rate of 35% due to net overall benefits from the aforementioned tax rate changes in Canada and the U.K. in that year.

At December 31, 2008, approximately 38% of the Company's U.S. proved oil reserves and 40% of the U.S. proved natural gas reserves are undeveloped. Virtually all of the total U.S. undeveloped reserves (on a barrel of oil equivalent basis) are associated with the Company's various deepwater Gulf of Mexico fields. Further drilling, facility construction and well workovers are required to move undeveloped reserves to developed. In Block K Malaysia, 23% of oil reserves of 76.6 million barrels and 25% of natural gas reserves of 106.5 billion cubic feet at year-end 2008 for the Kikeh field are undeveloped pending completion of facilities and continued development drilling, and 100% of the 15.1 million barrels of oil reserves at the Kakap field are undeveloped pending completion of drilling operations directed by another company. Also in Malaysia, there were 298.7 billion cubic feet of undeveloped natural gas reserves at various fields offshore Sarawak at year-end 2008, which were held under this category pending completion of development drilling and facilities. First gas production at the Kikeh field occurred in December 2008 and is scheduled for the Sarawak gas fields in the third quarter 2009. On a worldwide basis, the Company spent approximately $783 million in 2008, $769 million in 2007 and $560 million in 2006 to develop proved reserves. The Company expects to spend about $859 million in 2009, $377 million in 2010 and $250 million in 2011 to move currently undeveloped proved reserves to the developed category.

Exploration and Production Statistical Summary

	2008	2007	2006
Net crude oil, condensate and natural gas liquids production – barrels per day			
United States	10,668	12,989	21,112
Canada – light	46	596	443
heavy	8,484	11,524	12,613
offshore	16,826	18,871	14,896
synthetic	12,546	12,948	11,701
United Kingdom	4,869	5,281	7,146
Malaysia	57,403	20,367	11,298
Continuing operations	110,842	82,576	79,209
Discontinued operations	7,412	8,946	8,608
Total liquids produced	118,254	91,522	87,817
Net crude oil, condensate and natural gas liquids sold – barrels per day			
United States	10,668	12,989	21,112
Canada – light	46	596	443
heavy	8,484	11,524	12,613
offshore	16,690	18,839	15,360
synthetic	12,546	12,948	11,701
United Kingdom	5,739	5,218	6,678
Malaysia	61,907	16,018	11,986
Continuing operations	116,080	78,132	79,893
Discontinued operations	7,774	9,470	10,349
Total liquids sold	123,854	87,602	90,242
Net natural gas sold – thousands of cubic feet per day			
United States	45,785	45,139	56,810
Canada	1,910	9,922	9,752
United Kingdom	6,424	6,021	8,700
Malaysia	1,399	—	—
Total natural gas sold – continuing operations	55,518	61,082	75,262
Net hydrocarbons produced – equivalent barrels[1,2] per day	127,507	101,702	100,361
Estimated net hydrocarbon reserves – million equivalent barrels[1,2,3]	402.8	405.1	388.3
Weighted average sales prices[4]			
Crude oil, condensate and natural gas liquids – dollars per barrel			
United States	$ 95.74	65.57	57.30
Canada[5] – light	70.37	50.98	50.45
heavy	59.05	32.84	25.87
offshore	96.69	69.83	62.55
synthetic	100.10	74.35	63.23
United Kingdom	90.16	68.38	64.30
Malaysia[6]	87.83	74.58	51.78
Natural gas – dollars per thousand cubic feet			
United States	9.67	7.38	7.76
Canada[5]	6.40	6.34	6.49
United Kingdom[5]	10.98	7.54	7.34
Malaysia	0.23	—	—

1 Natural gas converted at a 6:1 ratio.
2 Includes synthetic oil.
3 At December 31.
4 Includes intercompany transfers at market prices.
5 U.S. dollar equivalent.
6 Prices are net of payments under the terms of the production sharing contracts for Blocks K and SK 309.

Refining and Marketing – The Company's refining and marketing (R&M) operations generated record earnings of $313.8 million in 2008, after earning $205.7 million in 2007 and $110.6 million in 2006. The 53% improvement in 2008 earnings compared to 2007 was caused by favorable U.K. refining profits following the acquisition of the remaining 70% of the Milford Haven refinery in December 2007, and nonrecurring charges in 2007 for a last-in, first-out (LIFO) inventory writedown in the U.K. and retail gasoline station impairments in North America.

The 86% improvement in R&M earnings in 2007 compared to 2006 was due to stronger refining margins in the U.S., lower hurricane-related expenses in 2007, and a fully operational Meraux refinery which was shut-down for repairs for about five months in 2006 following Hurricane Katrina. Total hurricane expenses after taxes in R&M operations were $1.9 million in 2007 and $67.1 million in 2006. The Meraux, Louisiana refinery significantly increased crude oil throughputs in 2007 compared to 2006 as the earlier year was unfavorably affected by downtime for repairs. R&M earnings in 2007 were net of two significant charges – a $24.5 million after-tax charge related to closure of 55 gasoline stations in the U.S. and Canada, and an after-tax inventory charge of $59.5 million in the U.K.

The Company's North American R&M operations generated earnings of $227.9 million in 2008, $230.4 million in 2007 and $77.5 million in 2006. North American operations include refining activities in the United States and marketing activities in the United States and Canada. North American R&M earnings were down slightly in 2008 compared to 2007 as lower profits generated by the U.S. refining operations were not quite offset by much stronger retail marketing profits in 2008. Demand for gasoline declined in the U.S. in 2008 due to higher costs and a weakening economy. This lower demand led to much tighter crack spreads for U.S. refineries in 2008 compared to 2007. Crack spreads represent the uplift of gasoline and distillate prices over the cost of crude oil feedstocks. Both U.S. refineries were temporarily shut-down for turnaround activities during 2008. The 2007 and 2006 operating results for the Company's North American refining business were negatively impacted by hurricane-related costs and below optimal Meraux refinery crude throughput volumes as a result of Hurricane Katrina. Uninsured damages, higher insurance premiums, settlement of the class action oil spill litigation and other hurricane-related pretax costs in the Company's North American operations were $3.0 million in 2007 and $107.3 million in 2006. The hurricane expense in 2007 was caused by a downward adjustment of expected insurance recoveries based on an updated loss limit published by the Company's primary insurer. The Meraux refinery throughput volumes of crude oil and other feedstocks averaged 103,169 barrels per day in 2008, 112,840 barrels per day in 2007 and 57,198 barrels per day in 2006. Significant flooding and wind damage associated with Hurricane Katrina resulted in the refinery being shut down from late August 2005 through May 2006. During the refinery's nine months of downtime for repairs, major upgrades and improvements were completed, and turnarounds on the refinery's hydrocracker and fluid catalytic cracking unit debutanizer were performed. The Company's refinery in Superior, Wisconsin also generated weaker earnings in 2008 than in 2007 as a result of tighter crack spreads in the later year. North American retail gasoline station operations had improved results in 2008 compared to 2007 as this business enjoyed higher per gallon margins, higher sales volumes and lower store closure costs compared to the prior year. This operation's business model of always offering competitive fuel prices usually leads to increased sales volumes during periods of high gasoline prices such as in the first nine months of 2008. The operating results for the Company's North American retail gasoline stations were lower in 2007 compared to 2006 as 55 underperforming stores were closed during 2007, including 47 in the U.S. and all eight stations in Canada. The Company recorded impairment expense of $38.2 million in 2007 associated with these store closures. Excluding this impairment charge, the 2007 operating results for this business would have been essentially flat with 2006. A total of 52 retail stations were added in the U.S. during 2008, including 21 in the parking lots of Walmart Supercenters and 31 at other stand-alone locations. Average fuel sales volumes per station increased again in 2008, the 11th straight year of improvements.

Unit margins (sales realization less costs of crude and other feedstocks, transportation to point of sale and refinery operating and depreciation expenses) averaged $4.30 per barrel in North America in 2008, $4.28 in 2007 and $3.48 in 2006. North American refined product sales volumes increased 3% to a record 427,490 barrels per day in 2008, following a 19% increase to 416,668 barrels per day in 2007. The Company's U.S. retail gasoline stations continued to increase per site fuel sales volumes with a 10% increase in the average monthly fuel sales volume per station in 2008 following a 4% increase in 2007.

Operations in the United Kingdom had earnings of $85.9 million in 2008 compared to a loss of $24.7 million in 2007 and earnings of $33.1 million in 2006. On December 1, 2007, the Company acquired 100% of the Milford Haven, Wales refinery, after having a 30% interest in the asset prior to that date. The improved earnings in 2008 compared to 2007 were mostly related to profits generated by the Milford Haven refinery as the refinery generated stronger margins in 2008 and the 2007 period included a significant inventory charge. In association with the late 2007 Milford Haven acquisition, the Company built a significant additional layer of crude oil and refined products inventory. The 2007 period included a $59.5 million after-tax non-cash charge to reduce the carrying value of these higher inventory levels to early 2007 prices. Under the Company's LIFO inventory accounting policy, inventory volume increases are priced at the first purchase prices during the year, and the prices of crude oil and refined products were at a much lower level in early 2007 compared to the price at the time these products were acquired near year-end 2007. The LIFO inventory charge reduced the average carrying value for these additional inventories in the U.K. by approximately $40 per barrel. Excluding this non-cash inventory charge, the 2007 operating result for the Company's U.K. operations was slightly improved over 2006. In late 2008, the Company purchased six existing fuel stations and leased an additional 63 stations in England and Scotland.

Unit margins in the United Kingdom averaged $4.30 per barrel in 2008, $0.22 per barrel in 2007 and $6.39 per barrel in 2006. Overall sales of refined products in the U.K. increased more than 200% in 2008, following an increase of 19% in 2007. The 2008 sales increase was attributable to additional quantities of refined products produced and sold throughout 2008 at the Milford Haven refinery following the Company's acquisition of the remaining 70% interest in December 2007.

Refining and Marketing Statistical Summary

	2008	2007	2006
Refining			
Crude capacity* of refineries – barrels per stream day	268,000	268,000	192,400
Refinery inputs – barrels per day			
Crude – Meraux, Louisiana	95,126	106,446	55,129
Superior, Wisconsin	26,580	32,737	34,066
Milford Haven, Wales	97,521	36,000	30,036
Other feedstocks	23,300	10,805	6,423
Total inputs	242,527	185,988	125,654
Refinery yields – barrels per day			
Gasoline	86,310	74,395	48,314
Kerosene	23,824	5,371	5,067
Diesel and home heating oils	75,526	67,111	42,137
Residuals	27,170	18,910	15,244
Asphalt, LPG and other	24,815	17,546	12,855
Fuel and loss	4,882	2,655	2,037
Total yields	242,527	185,988	125,654
Average cost of crude inputs to refineries – dollars per barrel			
North America	$ 96.46	69.40	59.54
United Kingdom	100.61	81.53	66.66
Marketing			
Products sold – barrels per day			
North America – Gasoline	313,827	298,833	266,353
Kerosene	4,606	1,685	2,269
Diesel and home heating oils	86,933	91,344	62,196
Residuals	14,837	15,422	11,696
Asphalt, LPG and other	7,287	9,384	8,087
	427,490	416,668	350,601
United Kingdom – Gasoline	34,125	14,356	12,425
Kerosene	14,835	4,020	3,619
Diesel and home heating oils	34,560	14,785	11,803
Residuals	12,744	3,728	3,825
LPG and other	15,246	4,213	2,998
	111,510	41,102	34,670
Total products sold	539,000	457,770	385,271
Branded retail outlets*			
North America – Murphy USA®	992	971	987
Murphy Express®	33	2	—
Other	129	153	177
Total	1,154	1,126	1,164
United Kingdom	454	389	402

* At December 31.

Corporate – The after-tax costs of corporate activities, which include interest income, interest expense, foreign exchange gains and losses, and corporate overhead not allocated to operating functions, were $171.8 million in 2008, $95.2 million in 2007 and $85.9 million in 2006. The net cost of corporate activities increased $76.6 million in 2008 compared to 2007 primarily due to higher costs associated with foreign exchange where transactions are denominated in currencies other than the operation's functional currency. Additionally interest costs, net of amounts capitalized to development projects, and administrative costs were also higher in 2008 than in 2007. The after-tax costs of foreign currency exchange amounted to $87.8 million in 2008 compared to costs of $13.8 million in 2007. The additional costs were primarily related to U.S. dollar transactions within the U.K.'s sterling functional downstream operations, as these dollar transactions expanded significantly with the 70% addition of Milford Haven, Wales refinery ownership beginning in December 2007. At year-end 2008 the U.S. dollar had strengthened 28% against the British pound sterling, 5% against the Euro, and 18% against the Canadian dollar compared to the end of 2007. Net interest expense increased $17.4 million in 2008 compared to 2007 mostly due to lower amounts of interest capitalized to ongoing oil and gas development projects during the just completed year. Administrative expenses in the corporate area increased in 2008 primarily due to higher total compensation expense and higher contributions to community and educational programs in the current year. Interest income increased $6.6 million in 2008 versus 2007 and was mostly associated with higher average short-term invested funds in Canada and the U.K. Income taxes in 2008 were favorable to 2007, and were primarily related to benefits on the higher foreign exchange losses and higher net interest expense as discussed above.

Net corporate costs increased $9.3 million in 2007 compared to 2006 due primarily to higher net interest expense and higher losses on foreign exchange. These higher costs were partially offset by lower costs in 2007 associated with an educational assistance commitment. Net interest expense rose by $15.3 million in 2007 compared to 2006 due to interest associated with higher average outstanding long-term debt balances. The Company's borrowings increased due to higher capital spending on oil and natural gas development projects in Malaysia, the Republic of the Congo and Canada, and in the downstream business related to capital spending for the purchase of the Milford Haven, Wales refinery and land underlying most gasoline stations at Walmart sites. The amount of interest capitalized to development projects increased in 2007 in association with higher capital development spending. The after-tax effect of foreign exchange was a charge of $13.8 million in 2007 compared to a charge of $7.9 million in 2006. The U.S. dollar weakened in 2007 by 17% against the Canadian dollar, 11% against the Euro and 2% against the British pound sterling. Administrative expenses in 2007 in the corporate area were significantly less than 2006 due mostly to lower costs associated with the El Dorado Promise educational assistance contribution, but partially offset by higher compensation costs in the current year. The El Dorado Promise involves the Company's commitment to contribute $5.0 million per year through 2016 to pay for post-secondary tuition for eligible graduates of El Dorado High School in Arkansas. Income taxes were unfavorable in the corporate area in 2007 compared to 2006 due to a higher portion of interest and administrative expenses allocable to foreign operations without current tax relief.

Capital Expenditures

As shown in the selected financial in Item 6 of this Form 8-K report, capital expenditures, including exploration expenditures, were $2,364.7 million in 2008 compared to $2,357.3 million in 2007 and $1,262.5 million in 2006. These amounts included capital expenditures related to discontinued operations in Ecuador. These amounts included $232.4 million, $169.6 million and $195.2 million, respectively, in 2008, 2007 and 2006 for exploration costs that were expensed. Capital expenditures for exploration and production continuing operations totaled $1,928.3 million in 2008, $1,740.3 million in 2007 and $1,046.5 million in 2006, representing 82%, 75% and 85%, respectively, of the Company's total capital expenditures from continuing operations for these years. E&P capital expenditures in 2008 included $156.0 million for acquisition of undeveloped leases, which included leases acquired in the eastern and central Gulf of Mexico and at the Tupper area of northeastern British Columbia, $323.6 million for exploration activities, and $1,448.7 million for development projects. Development expenditures included $358.3 million for the Tupper natural gas area in British Columbia, $160.2 million for deepwater fields in the Gulf of Mexico; $325.7 million for the Kikeh field in Malaysia; $287.8 million for natural gas and other development activities in SK Blocks 309/311; $46.5 million for development of the Kakap field in Block K, offshore Malaysia; $35.6 million for synthetic oil operations at the Syncrude project in Canada; $37.6 million for western Canada heavy oil projects; $149.2 million for development of the Azurite field in the Republic of the Congo; $18.0 million for the Terra Nova and Hibernia oil fields, offshore Newfoundland; and $22.1 million for fields in the U.K. North Sea. Exploration and production capital expenditures are shown by major operating area on page F-38 of this Form 8-K report.

Refining and marketing capital expenditures totaled $426.2 million in 2008, $572.5 million in 2007 and $173.4 million in 2006. These amounts represented 18%, 25% and 14% of capital expenditures from continuing operations of the Company in 2008, 2007 and 2006, respectively. Refining capital spending was $141.8 million in 2008 compared to $330.0 million in 2007 and $57.3 million in 2006. Refining capital in 2008 included project costs for additional sulfur recovery capacity and property acquisition and improvements at the Meraux, Louisiana refinery, and a cogeneration energy plant at the Milford Haven, Wales refinery. The 2007 refining capital included $240.7 million for acquisition of the remaining 70%

of the Milford Haven, Wales refinery. Most of the remaining refinery capital in 2007 was related to property acquired surrounding the Meraux refinery. The bulk of the refining capital in 2006 was spent at the Meraux refinery where numerous capital improvements were completed while the plant was shut-down for repairs following Hurricane Katrina. Marketing expenditures amounted to $284.4 million in 2008, $242.5 million in 2007 and $116.1 million in 2006. Marketing capital spending in 2008 was split between station construction costs and land acquisitions costs for existing and future retail gasoline stations. The capital spending in 2007 was mostly attributable to acquisition of land underlying retail gasoline stations located at Walmart Supercenters. The majority of marketing expenditures in 2006 was related to construction of retail gasoline stations at Walmart Supercenters in the U.S. The Company added 52 stations within its U.S. retail gasoline network in 2008, after adding 33 in 2007 and 123 in 2006.

Cash Flows

Cash provided by operating activities was $3.04 billion in 2008, $1.74 billion in 2007 and $975.5 million in 2006. Cash provided by operating activities in 2008 was $1.30 billion more than in 2007 primarily due to higher net income, higher depreciation and higher exploration drilling expenditures. Cash provided by operating activities in 2007 was approximately $765 million more than in 2006 mostly due to a combination of higher net income, higher expenses for depreciation, impairment and deferred taxes, and a reduction of noncash operating working capital in 2007 versus an increase in 2006. Cash provided by operating activities in 2006 was unfavorably affected by lower oil and natural gas sales volumes and higher operating costs associated with repairs of oil and gas production facilities. Cash provided by operating activities was reduced by expenditures for abandonment of oil and gas properties totaling $9.2 million in 2008, $13.0 million in 2007 and $3.3 million in 2006.

Cash proceeds from property sales were $362.0 million in 2008, $21.6 million in 2007 and $23.8 million in 2006. The 2008 proceeds related to sales of two of the Company’s Canadian assets, including its interest in Berkana Energy and the Lloydminster heavy oil property, and a sale of 35% of its working interest in the MPS block offshore the Republic of the Congo. The sales proceeds in 2007 and 2006 primarily related to sales of various properties, real estate and aircraft. During 2008, the Company used available cash flow to repay $492.8 million of long-term debt. During 2007 and 2006, the Company borrowed $686.2 million and $237.7 million, respectively, under notes payable primarily to fund a portion of the Company’s development capital expenditures. Cash proceeds from stock option exercises and employee stock purchase plans, including income tax benefits on stock options classified as financing activities, amounted to $50.0 million in 2008, $72.4 million in 2007 and $36.6 million in 2006. Proceeds from maturities of Canadian government securities with maturities greater than 90 days at date of acquisition was $623.1 million in 2008.

Property additions and dry hole costs used cash of $2.18 billion in 2008, $1.91 billion in 2007 and $1.16 billion in 2006. The higher capital expenditures in 2008 compared to 2007 were primarily associated with a more robust exploration program and higher spending on development projects including Kikeh development drilling, Sarawak natural gas, Kakap, Azurite, Tupper and Thunder Hawk. Higher amounts spent in 2007 compared to 2006 mostly related to ongoing E&P development projects, including Kikeh, Azurite, Sarawak gas and one field in the Gulf of Mexico, acquisition of mineral rights in the Tupper area of western Canada, and purchases of land under Company-owned gasoline stations at Walmart stores and surrounding the Meraux refinery. In December 2007, the Company spent $348.3 million to acquire the remaining 70% interest in the Milford Haven, Wales refinery and associated inventory. Cash of $1.04 billion was spent in 2008 to acquire Canadian government securities with maturities greater than 90 days at the time of purchase. Cash of $57.6 million in 2008, $14.6 million in 2007 and $12.8 million in 2006 was used for turnarounds at refineries and Syncrude. Cash used for dividends to stockholders was $166.5 million in 2008, $127.4 million in 2007 and $98.2 million in 2006. The Company raised its annualized dividend rate from $0.75 per share to $1.00 per share beginning in the third quarter of 2008. The Company had previously increased the annualized dividend rate from $0.60 per share to $0.75 per share beginning in the third quarter of 2007.

Financial Condition

Year-end working capital (total current assets less total current liabilities) totaled $958.8 million in 2008 and $777.5 million in 2007. The current level of working capital does not fully reflect the Company’s liquidity position as the carrying value for inventories under last-in, first-out accounting was $202.5 million below fair value at December 31, 2008. Cash and cash equivalents at the end of 2008 totaled $666.1 million compared to $673.7 million at year-end 2007.

The long-term portion of debt decreased by $489.9 million during 2008 and totaled $1.03 billion at year-end 2008, representing 14.0% of total capital employed. Available free cash flow arising primarily from strong crude oil sales prices was used to repay a portion of long-term debt during 2008. Long-term debt increased by $675.9 million in 2007 as the Company utilized its borrowing capacity to fund its significant ongoing oil and natural gas development projects, with the largest of these being the Kikeh field in Malaysia. Stockholders’ equity was $6.28 billion at the end of 2008 compared to $5.07 billion a year ago and $4.12 billion at the end of 2006. A summary of transactions in stockholders’ equity accounts is presented on page F-5 of this Form 8-K report.

Other significant changes in Murphy's year-end 2008 balance sheet compared to 2007 included a $420.3 million balance of short-term investments in Canadian government securities with maturities greater than 90 days at the time of purchase. There were no such investments with maturities greater than 90 days at December 31, 2007. These slightly longer-term investments were purchased in 2008 because of a tight supply of shorter-term securities available for purchase in Canada. A $386.6 million decrease in accounts receivable was caused by sales of crude oil and refined petroleum products at lower average prices near the end of 2008 compared to 2007. Inventory values were $22.5 million lower at year-end 2008 than in 2007 mostly due to less unsold crude oil production held in inventory at year-end 2008 compared to 2007. Prepaid expenses increased $13.0 million in 2008 primarily due to higher prepaid income taxes in the U.K. Short-term deferred income tax assets decreased $56.5 million at year-end 2008 due mostly to changes in the components of temporary differences for the Company's Canadian operations. Net property, plant and equipment increased by $617.9 million in 2008 as a significant level of property additions during the year exceeded the additional depreciation and amortization expensed. Goodwill decreased $14.1 million in 2008 due to a weaker Canadian dollar exchange rate versus the U.S. dollar and an allocation of a portion of goodwill to costs associated with the sale of properties in Canada. Deferred charges and other assets increased $49.3 million and included higher amounts of deferred turnaround costs following major maintenance performed during the year at the Company's U.S. refineries. Current maturities of long-term debt declined $2.6 million during 2008 due to a partial repayment of nonrecourse debt associated with the Hibernia field. Notes payable decreased $7.6 million in 2008 as this borrowing at year-end 2007 was associated with Berkana Energy Corp., which Murphy sold in January 2008. Accounts payable declined by $487.8 million at year-end 2008 compared to 2007 mostly due to lower amounts owed for crude oil purchases. Income taxes payable increased $342.6 million at year-end 2008 primarily due to higher taxes owed in the current year on income in Malaysia. Other taxes payable decreased $47.8 million mostly due to lower excise and value added taxes owed by the Company's U.K. operations at year-end 2008 compared to 2007. Other accrued liabilities decreased by $18.0 million in 2008 mostly due to lower employee compensation liabilities in the current year. Deferred income tax liabilities were $38.8 million lower at year-end 2008 due mostly to lower liabilities for future taxes in the U.K. and Canada. The liability associated with future asset retirement obligations increased by $99.5 million mostly due to development wells drilled during 2008 offshore Malaysia and higher estimated future costs for abandonment of existing facilities at the Company's synthetic oil operations in Canada. Deferred credits and other liabilities increased $50.8 million in 2008 compared to 2007 mostly due to higher long-term liabilities associated with employee retirement plans.

Murphy had commitments for future capital projects of approximately $2.13 billion at December 31, 2008, including $172.9 million for costs to develop deepwater Gulf of Mexico fields, $1.02 billion for field development and future work commitments in Malaysia, and $322.5 million for field development and a work commitment in the Republic of the Congo.

The primary sources of the Company's liquidity are internally generated funds, access to outside financing and working capital. The Company uses its internally generated funds to finance the major portion of its capital and other expenditures, but it also maintains lines of credit with banks and borrows as necessary to meet spending requirements. At December 31, 2008, the Company had access to a long-term committed credit facility in the amount of $1.962 billion. A total of $318.5 million was borrowed under the committed credit facility at year-end 2008. The most restrictive covenants under this committed credit facility limit the Company's long-term debt to capital ratio (as defined in the agreements) to 60%. At December 31, 2008, the long-term debt to capital ratio was approximately 14.0%. At December 31, 2008, the Company had borrowed $110 million under uncommitted credit lines. The Company's shelf registration on file with the U.S. Securities and Exchange Commission that permitted the offer and sale of up to $650 million in debt and/or equity securities expired on December 31, 2008. The Company expects to file a new shelf registration in the second quarter of 2009. Current financing arrangements are set forth more fully in Note F to the consolidated financial statements. The Company anticipates matching its spending plans to cash inflows during 2009 in order to borrow little or no funds under its available credit facilities during the year. However, under a continued low price environment for oil and natural gas, the Company may have to borrow under these credit facilities to fund ongoing development projects. At February 27, 2009, the Company's long-term debt rating by Standard & Poor's was "BBB" and by Moody's Investors Service was "Baa3". The Company has a rating of A (low) from Dominion Bond Rating Service. The Company's ratio of earnings to fixed charges was 28.3 to 1 in 2008, 14.0 to 1 in 2007 and 15.1 to 1 in 2006.

Environmental Matters

Murphy and other companies in the oil and gas industry are subject to numerous federal, state, local and foreign laws and regulations dealing with the environment. Compliance with existing and anticipated environmental regulations affects our overall cost of business. Areas affected include capital costs to construct, maintain and upgrade equipment and facilities, in concert with ongoing operating costs for environmental compliance. Anticipated and existing regulations affect our capital expenditures and earnings, and they may affect our competitive position to the extent that regulatory requirements with respect to a particular production technology may give rise to costs that our competitors might not bear. Environmental regulations have historically been subject to frequent change by regulatory authorities, and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of such regulations on our operations. Violation of federal or state environmental laws, regulations and permits can result in the imposition of significant civil and criminal penalties, injunctions and construction bans or delays. A discharge of hazardous substances into the environment could, to the extent such event is not insured, subject us to substantial expense, including both the cost to comply with applicable regulations and claims by neighboring landowners and other third parties for any personal injury and property damage that might result.

The most significant of those laws and the corresponding regulations affecting our U.S. operations are:

- The U.S. Clean Air Act, which regulates air emissions
- The U.S. Clean Water Act, which regulates discharges into U.S. waters
- The U.S. Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which addresses liability for hazardous substance releases
- The U.S. Federal Resource Conservation and Recovery Act (RCRA), which regulates the handling and disposal of solid wastes
- The U.S. Federal Oil Pollution Act of 1990 (OPA90), which addresses liability for discharges of oil into navigable waters of the United States
- The U.S Safe Drinking Water Act, which regulates disposal of wastewater into underground wells
- Regulations of the U.S. Department of the Interior governing offshore oil and gas operations.

These laws and their associated regulations establish limits on emissions and standards for quality of air, water and solid waste discharges. They also generally require permits for new or modified operations. Many states and foreign countries where the Company operates also have or are developing similar statutes and regulations governing air and water as well as the characteristics and composition of refined products, which in some cases impose or could impose additional and more stringent requirements. We are also subject to certain acts and regulations, including legal and administrative proceedings, governing remediation of wastes or oil spills from current and past operations, which include but may not be limited to leaks from pipelines, underground storage tanks and general environmental operations.

CERCLA commonly referred to as the Superfund Act, and comparable state statutes primarily address historic contamination and impose joint and several liability upon Potentially Responsible Parties (PRP), without regard to fault or the legality of the original act that contributed to the release of a “hazardous substance” into the environment. Cleanup of contaminated sites is the responsibility of the owners and operators of the sites that released, disposed, or arranged for the disposal of the hazardous substances found at the site. CERCLA also authorizes the U.S. Environmental Protection Agency (EPA) and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible persons. In the course of our ordinary operations, we generate waste that falls within CERCLA’s definition of a “hazardous substance.” We may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which such hazardous substances have been disposed of or released into the environment. CERCLA also requires reporting of releases to the environment of substances defined as hazardous or extremely hazardous and must be reported to the National Response Center, if they exceed an EPA established reportable quantity.

The EPA currently considers us to be a PRP at two Superfund sites. The potential total cost to all parties to perform necessary remedial work at these sites may be substantial. However, based on current negotiations and available information, we believe that we are a de minimis party as to ultimate responsibility at these Superfund sites. We have not recorded a liability for remedial costs on Superfund sites. We could be required to bear a pro rata share of costs attributable to nonparticipating PRPs or could be assigned additional responsibility for remediation at these sites or other Superfund sites. We believe that our share of the ultimate costs to clean-up the Superfund sites will be immaterial and will not have a material adverse effect on Murphy’s net income, financial condition or liquidity in a future period.

We currently own or lease, and have in the past owned or leased, properties at which hazardous substances have been or are being handled. Although we have used operating and disposal practices that were standard in the industry at the time, hazardous substances may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes were not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. While some of these historical properties are in various stages of negotiation, investigation, and/or cleanup, we are investigating the extent of any such liability and the availability of applicable defenses and believe costs related to these sites will not have a material adverse affect on Murphy’s net income, financial condition or liquidity in a future period.

RCRA and comparable state statutes govern the management and disposal of solid wastes, with the most stringent regulations applicable to treatment, storage or disposal of hazardous wastes. We generate non-hazardous solid wastes that are subject to the requirements of RCRA and comparable state statutes. Our operating sites also incur costs to handle and dispose of hazardous waste and other chemical substances. The types of waste and substances disposed of generally fall into the following categories: spent catalysts (usually hydro-treating catalysts); spent/used filter media; tank bottoms and API separator sludge; contaminated soils; laboratory and maintenance spent solvents; and industrial debris. The costs of disposing of these substances are expensed as incurred and are not expected to have a material adverse effect on net income, financial condition or liquidity in a future period. However, it is possible that additional wastes, which could include wastes currently generated during operations, will in the future be designated as "hazardous wastes." Hazardous wastes are subject to more rigorous and costly disposal requirements than are non-hazardous wastes. Such changes in the regulations could result in additional capital expenditures and operating expenses.

Murphy allocates a portion of its capital expenditure program to comply with environmental laws and regulations, and such capital expenditures were $121.7 million in 2008 and are projected to be $132.6 million in 2009.

Our liability for remedial obligations includes certain amounts that are based on anticipated regulatory approval for proposed remediation of former refinery waste sites. Although regulatory authorities may require more costly alternatives than the proposed processes, the cost of such potential alternative processes is not expected to exceed the accrued liability by a material amount. Certain environmental expenditures are likely to be recovered by us from other sources, primarily environmental funds maintained by certain states. Since no assurance can be given that future recoveries from other sources will occur, we have not recorded a benefit for likely recoveries as of December 31, 2008.

We are also involved in personal injury and property damage claims, allegedly caused by exposure to or by the release or disposal of materials manufactured or used in our operations. Under our accounting policies, an environmental liability is recorded when such an obligation is probable and the cost can be reasonably estimated. If there is a range of reasonably estimated costs, the most likely amount will be recorded, or if no amount is most likely, the minimum of the range is used. Recorded liabilities are reviewed quarterly. Actual cash expenditures often occur one or more years after a liability is recognized.

Under OPA90, owners and operators of tankers, owners and operators of onshore facilities and pipelines, and lessees or permittees of an area in which an offshore facility is located are liable for removal and cleanup costs of oil discharges into navigable waters of the United States. To the best of our knowledge, there has been no such OPA90 claims made against Murphy.

The EPA has issued several standards applicable to the formulation of motor fuels, primarily related to the level of sulfur found in highway diesel and gasoline, which are designed to reduce emissions of certain air pollutants when the fuel is used. Several states have passed similar or more stringent regulations governing the formulation of motor fuels. The EPA's mandated requirements for low-sulfur gasoline are effective in 2008 and both of our U.S. refineries have been expanded and are now capable of producing the required low-sulfur gasoline. Each of the U.S. refineries must begin to produce the EPA required ultra low-sulfur diesel (ULSD) beginning in 2010. The Meraux refinery is currently capable of producing this ULSD for approximately half of its diesel production, but the Superior refinery is not yet capable of meeting the ULSD standard. Our management is currently studying alternatives available for fully meeting this ULSD standard at Meraux and Superior.

The Energy Independence and Security Act (EISA) was signed into law in December 2007. The EIS Act through EPA regulation requires refiners and gasoline blenders to obtain renewable fuel volume or representative trading credits as a percentage of their finished product production. This Act greatly increases the renewable fuels obligation defined in the Renewable Fuels Standard which began in September 2007. Murphy is actively blending renewable fuel volumes through its retail and wholesale operations and trading corresponding credits known as Renewable Identification Numbers (RINs) to meet its obligation.

The Federal Water Pollution Control Act of 1972 (FWPCA) imposes restrictions and strict controls regarding the discharge of pollutants into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA imposes substantial potential liability for the costs of removal, remediation and damages. We maintain wastewater discharge permits for our facilities where they are required pursuant to the FWPCA and comparable state laws. We have also applied for all necessary permits to discharge storm water under such laws. We believe that compliance with existing permits and foreseeable new permit requirements will not have a material adverse effect on our net income, financial condition or liquidity in a future period.

Our U.S. operations are subject to the Federal Clean Air Act and comparable state and local statutes. We believe that our operations are in substantial compliance with these statutes in all states in which we operate. Amendments to the Federal Clean Air Act enacted in late 1990 require or will require most refining operations in the U.S. to incur capital expenditures in order to meet air emission control standards developed by the EPA and state environmental agencies.

Under the EPA's Clean Air Act authority, the National Petroleum Refinery (NPR) Initiative (Global Consent Decree) was initiated as a national priority to investigate four marquee compliance areas for refinery operations: (i) New Source Review/Prevention of Significant Deterioration for fluidized catalytic cracking units, heaters and boilers; (ii) New Source Performance Standards for flares, sulfur recovery units, fuel gas combustion devices (including heaters and boilers); (iii) Leak Detection and Repair requirements; and (iv) Benzene National Emissions Standards for Hazardous Air Pollutants. Murphy, in 2005 began negotiations with the EPA, which were interrupted by the events of Hurricane Katrina. Both the state of Louisiana and Wisconsin are parties to the NPR. Negotiations with EPA resumed in 2007 and are continuing. While substantial progress has been made in these negotiations, the Company is unable at this time to predict the capital costs, operating costs and potential fines or penalties that may occur in the future upon conclusion of the NPR negotiations.

Our Meraux, Louisiana refinery is also currently negotiating with the Louisiana Department of Environmental Quality (LDEQ) regarding three Compliance Order/Notice of Proposed Penalty (CO/NOPP) notifications regarding air and water discharges. While we are in various stages of negotiations and/or settlement, the Company is unable to predict the costs that it will incur related to these CO/NOPP negotiations.

World leaders have held numerous discussions about the level of worldwide greenhouse gas emissions. As part of these discussions, the Kyoto Agreement was adopted in 1997 and was ratified by certain countries in which we operate or may operate in the future, with the United States being the primary country that has yet to ratify the agreement. The agreement became effective for ratifying countries in 2005 and these countries have implemented regulations or are in various stages of developing regulations to address its contents that ultimately target a reduction in greenhouse gas emissions. We are unable to predict how U.S. regulations (if any) associated with the Kyoto Agreement will impact costs in future years. The European Union has adopted an Emissions Trading Scheme in response to the Kyoto Agreement in order to achieve reductions in greenhouse gas emissions. Our refining operations at Milford Haven currently have the most exposure to these requirements and may require purchase of emission allowances to maintain compliance with environmental permit requirements. These environmental expenditures are expensed as incurred.

Currently, various national and international legislative and regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane and nitrous oxides) are in various phases of discussion or implementation. These include proposed U.S. federal legislation and state actions to develop statewide or regional programs, each of which have imposed or would impose mandatory reporting and reductions in greenhouse gas emissions. These actions could result in increased costs to (i) operate and maintain our facilities; (ii) install new emission controls on our facilities; and (iii) administer and manage any greenhouse gas emissions program. These actions could also impact the consumption of refined products, thereby affecting our refinery operations. The Company is unable to predict at this time how much the cost of compliance with any future U.S. legislation or regulation of greenhouse gas emissions, if it occurs, will be in future periods. Proactively, Murphy has instituted an internal Climate Change workgroup, conducts annual greenhouse gas inventories and participates in the Massachusetts Institute of Technology (MIT) Joint Program on the Science and Policy of Global Change.

Safety Matters

We are also subject to the requirements of the Federal Occupational Safety and Health Act (OSHA) and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that certain information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with OSHA requirements, including general industry standards, record-keeping requirements and monitoring of occupational exposure to regulated substances.

In 2007, OSHA announced a National Emphasis Program (NEP) for inspecting all refineries in the U.S. for compliance with OSHA's Process Safety Management (PSM) regulations. OSHA completed an inspection of our Superior, Wisconsin refinery in February 2008 and issued several compliance related citations and a penalty of $179,000. As of December 31, 2008, all of the cited OSHA items have been abated.

Other Matters

Impact of inflation – General inflation was moderate during the last three years in most countries where the Company operates; however, the Company's revenues and capital and operating costs are influenced to a larger extent by specific price changes in the oil and gas and allied industries than by changes in general inflation. Crude oil and petroleum product prices generally reflect the balance between supply and demand, with crude oil prices being particularly sensitive to OPEC production levels and/or attitudes of traders concerning supply and demand in the near future. Natural gas prices are affected by supply and demand, which to a significant extent are affected by the weather and by the fact that delivery of gas is generally restricted to specific geographic areas. Prices for oil field goods and services have generally risen (with certain of these price increases such as drilling rig day rates having been significant) during the last few years primarily driven by high demand for such goods and services when oil and gas prices were strong. As noted earlier, oil and natural gas prices have fallen significantly in late 2008 and early 2009, however, the prices for oil goods and services have not generally declined in tandem with oil and gas prices. Should a lower price environment for oil and gas continue, the Company anticipates that prices for certain equipment and services will decline due to falling demand for such items. Due to the volatility of oil and natural gas prices, it is not possible to determine what effect these prices will have on the future cost of oil field goods and services.

Accounting changes and recent accounting pronouncements – In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement applies under other accounting pronouncements that require or permit fair value measurements, and where applicable simplifies and codifies related guidance within GAAP and does not require any new fair value measurements. The statement was originally effective for fiscal years beginning January 1, 2008. On February 12, 2008, the FASB issued FSP No. 157-2 that delayed for one year the effective date of SFAS No. 157 for most nonfinancial assets and nonfinancial liabilities. Provisions of the statement are to be applied prospectively except in limited situations. The Company adopted this statement as of January 1, 2008 and the adoption had no material impact on its consolidated financial statements. See further disclosures at Note O to the consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS No. 159). This pronouncement permits companies with eligible financial assets and financial liabilities to measure these items at fair value in the financial statements. This option to measure at fair value is both instrument specific and irrevocable. If the fair value option is elected, certain additional disclosures are required and financial statements for periods prior to the adoption may not be restated. This pronouncement was effective January 1, 2008 for the Company. The Company chose not to elect fair value measurement for any financial assets and financial liabilities, and therefore, the adoption of SFAS No. 159, had no impact on the Company's consolidated balance sheet or consolidated statement of income.

In June 2007, the FASB ratified the Emerging Issues Task Force's Issue No. 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards (EITF 06-11). This new guidance was effective for the Company beginning January 1, 2008 and required that income tax benefits received by the Company for dividends paid on share-based incentive awards be recorded in Capital in Excess of Par Value in Stockholders' Equity. Under certain circumstances, such tax benefits received on awards that do not vest could be reclassified to reduce income tax expense in the Consolidated Statements of Income. The effect of adopting EITF No. 06-11 in 2008 was not material to the Company's consolidated financial statements.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51. This statement is effective for the Company beginning January 1, 2009. Upon adoption, this statement will require noncontrolling interests to be reclassified as equity, and consolidated net income and comprehensive income shall include the respective results attributable to noncontrolling interests. It is to be applied prospectively and early adoption is not permitted. The Company does not expect this statement to have a significant effect on its consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations. This statement establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquired business. It also establishes how to recognize and measure goodwill acquired in the business combination or a gain from a bargain purchase, if applicable. This statement shall be applied prospectively by the Company to any business combination that occurs on or after January 1, 2009. Early application is prohibited. Assets and liabilities that arise from business combinations occurring prior to 2009 shall not be adjusted upon application of this statement. This statement will impact the recognition and measurement of assets and liabilities in business combinations that occur after 2008, and the Company is unable to predict at this time how the application of this statement will affect its financial statements in future periods.

In March 2008, the FASB issued SFAS No. 161, Disclosure about Derivative Instruments and Hedging Activities. This statement is effective for the Company beginning in January 2009, and it expands required disclosures regarding derivative instruments to include qualitative information about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. The Company does not expect this statement to have a significant effect on its consolidated financial statements.

In June 2008, the FASB issued FASB Staff Position on EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities (FSP EITF 03-6-1). This statement provides that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings per share (EPS) calculation under the two-class method. All prior-period EPS calculations must be adjusted retrospectively. This statement is effective for the Company in 2009. Although the Company is in the process of evaluating this statement, it does not expect the effect of adopting this statement in 2009 to have a significant impact on its prior-period EPS calculations.

In December 2008, the FASB issued Staff Position No. FAS 132(R)-1, Employers' Disclosures about Postretirement Benefit Plan Assets. This guidance will require additional disclosures about benefit plan assets, including how asset investment allocation decisions are made, the fair value of each major category of plan assets, and how fair value is determined for each major asset category. This guidance is effective for the Company at year-end 2009. Upon adoption, no comparative disclosures are required for earlier years presented. The Company does not expect the adoption of this standard to have a material impact on its consolidated financial statements in future periods.

In November 2008, the EITF published Issue No. 08-6, Equity Method Investment Accounting Considerations. This pronouncement gives guidance about how to initially measure contingent consideration for an equity method investment, how to recognize other-than-temporary impairments of an equity method investment, and how an equity method investor is to account for a share issuance by an investee. This guidance is effective for the Company at the beginning of its 2009 fiscal year. The guidance is to be applied prospectively and early adoption is not permitted. The Company is currently evaluating this guidance and is unable to predict at this time how it will impact its consolidated financial statements in future periods.

Significant accounting policies – In preparing the Company's consolidated financial statements in accordance with U.S. generally accepted accounting principles, management must make a number of estimates and assumptions related to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Application of certain of the Company's accounting policies requires significant estimates. The most significant of these accounting policies and estimates are described below.

- *Proved oil and natural gas reserves* – Proved reserves are defined by the U.S. Securities and Exchange Commission (SEC) as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although the Company's engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. SEC rules require that year-end oil and natural gas prices must be used for determining proved reserve quantities. Year-end prices usually do not approximate the average price that the Company expects to receive for its oil and natural gas production. The Company often uses significantly different oil and natural gas price and reserve assumptions when making its own internal economic property evaluations. Estimated reserves are subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of the Company's depreciation rates and the timing of settlement of asset retirement obligations.

  The Company's proved reserves of oil and natural gas are presented on page F-36 of this Form 8-K. An unfavorable U.S. oil revision in 2008 resulted from updated reservoir modeling of one field in the deepwater Gulf of Mexico. An unfavorable revision in Canada in 2008 was related to low heavy oil prices at year-end, but this was partially offset by a favorable impact from better field performance at Hibernia. A favorable oil reserve revision in Malaysia was attributable to better than anticipated drilling results and additional drilling opportunities in the main reservoir at the

Kikeh field, coupled with better reservoir performance and artificial lift improvements at the West Patricia field. An unfavorable oil reserve revision in the U.S. in 2007 was mostly related to poor performance at one deepwater field in the Gulf of Mexico. Favorable oil reserve revisions in 2007 in Canada relate primarily to better performance at the Hibernia and Terra Nova fields. Favorable 2007 oil revisions in Malaysia relate to West Patricia and Kikeh well performances. The oil reserve revisions in 2006 in the U.S., Canada, Malaysia and Ecuador were based on performance of various local wells. The favorable oil reserve revision in Malaysia in 2006 was mostly due to extension of proved oil in the Kikeh reservoir. An unfavorable natural gas reserve revision in Malaysia in 2008 was related to entitlement adjustments under the Sarawak Blocks SK 309 and SK 311 production sharing contract and gas volumes lost due to operational delays that restricted sales volumes at the Kikeh field, offshore Sabah. Downward revisions to U.S. natural gas reserves in 2007 and 2006 were mostly caused by unfavorable production performance for gas wells at various fields in the Gulf of Mexico and onshore south Louisiana. The favorable natural gas reserve revision in Canada in 2007 is mostly attributable to well performance at the natural gas field owned by a consolidated subsidiary. The downward revision to 2007 natural gas reserves in Malaysia is based on higher contractual sales prices at year-end 2007 compared to 2006. The significant upward revision of natural gas reserves in Malaysia in 2006 related to gas associated with the Kikeh field that will be sold to the local government beginning in 2008. The Company cannot predict the type of reserve revisions that will be required in future periods.

On December 29, 2008, the SEC adopted revisions to oil and natural gas reserve reporting requirements which are effective for the Company at year-end 2009, unless the timing is subsequently amended. Among other things, the rule:

- revises the definition of proved reserves, including the pricing used to determine economic producibility,
- expands the definition of oil and gas producing activities to include non-traditional and unconventional resources, which includes the Company's synthetic oil operations in Alberta, and
- allows, but does not require, companies to disclose probable and possible reserves in SEC filings.

The Company is currently evaluating these new rules and cannot predict how the new rules will affect its future reporting of oil and natural gas reserves. The full rule is available at the SEC's website at www.sec.gov.

- *Successful efforts accounting* – The Company utilizes the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration wells are expensed and can have a significant effect on net income. Successful exploration drilling costs, all development capital expenditures and asset retirement costs are capitalized and systematically charged to expense using the units of production method based on proved developed oil and natural gas reserves as estimated by the Company's engineers.

In some cases, a determination of whether a drilled well has found proved reserves can not be made immediately. This is generally due to the need for a major capital expenditure to produce and/or evacuate the hydrocarbon(s) found. The determination of whether to make such a capital expenditure is, in turn, usually dependent on whether additional exploratory wells find a sufficient quantity of additional reserves. Under current accounting rules, the Company holds well costs in Property, Plant and Equipment in the Consolidated Balance Sheet when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Based on the time required to complete further exploration and appraisal drilling in areas where hydrocarbons have been found but proved reserves have not been booked, dry hole expense may be recorded one or more years after the original drilling costs are incurred. Dry hole expense related to wells drilled in a prior year was $3.4 million in 2006; there were no dry holes in 2008 or 2007 that were drilled in prior years.

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

  In making its impairment assessments involving exploration and production property and equipment, the Company must make a number of projections involving future oil and natural gas sales prices, future production volumes, and future capital and operating costs. Due to the volatility of world oil and gas markets, the actual sales prices for oil and natural gas have often been quite different from the Company's projections. Estimates of future oil and gas production and sales volumes are based on a combination of proved and risked probable and possible reserves. Although the estimation of reserves and future production is uncertain, the Company believes that its estimates are reasonable; however, there have been cases where actual production volumes were higher or lower than projected and the timing was different than the original projection. The Company adjusts reserves and production estimates as new information becomes available. The Company generally projects future costs by using historical costs adjusted for both assumed long-term inflation rates and known or expected changes in future operations. Although the projected future costs are considered to be reasonable, at times, costs have been higher or lower than originally estimated. In assessing potential impairment involving refining and marketing assets, the Company evaluates its properties when circumstances indicate that carrying value of an asset may not be recoverable from future cash flows. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events, which include projections of future margins, future capital expenditures and future operating expenses. Future marketing or operating decisions, such as closing or selling certain assets, and future regulatory or tax changes could also impact the Company's conclusion about potential asset impairment. Based on an evaluation of expected future cash flows from properties at year-end 2008, the Company does not believe it had any significant properties with carrying values that were impaired at that date. The expected future sales prices for crude oil and natural gas used in the evaluation were based on quoted future prices for the respective production periods. These quoted prices generally reflected higher expected prices for oil and natural gas in the future compared to the existing spot prices at the end of 2008. If quoted prices for future years had been lower, the smaller projected cash flows for properties could have led to significant impairment charges being recorded for certain properties in 2008. In addition, one or a combination of factors such as lower future sales prices, lower future production, higher future costs, lower future margins on refining and marketing sales, or the actions of government authorities could lead to impairment expenses in future periods. Based on these unknown future factors as described herein, the Company can not predict the amount or timing of impairment expenses that may be recorded in the future.

- *Income taxes* – The Company is subject to income and other similar taxes in all areas in which it operates. When recording income tax expense, certain estimates are required because: (a) income tax returns are generally filed months after the close of its annual accounting period; (b) tax returns are subject to audit by taxing authorities and audits can often take years to complete and settle; and (c) future events often impact the timing of when income tax expenses and benefits are recognized by the Company. The Company has deferred tax assets mostly relating to basis differences for property, equipment and inventories, and dismantlements and retirement benefit plan liabilities. The Company routinely evaluates all deferred tax assets to determine the likelihood of their realization. A valuation allowance has been recognized for deferred tax assets related to basis differences for Blocks H, PM 311/312, P, L and M in Malaysia, exploration licenses in the Republic of the Congo and Australia, and certain basis differences in the U.K. due to management's belief that these assets cannot be deemed to be realizable with any degree of confidence at this time. The Company occasionally is challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in its various income tax returns. Although the Company believes that it has adequate accruals for matters not resolved with various taxing authorities, gains or losses could occur in future years from changes in estimates or resolution of outstanding matters.

- *Accounting for retirement and postretirement benefit plans* – Murphy Oil and certain of its subsidiaries maintain defined benefit retirement plans covering most of its full-time employees. The Company also sponsors health care and life insurance benefit plans covering most retired U.S. employees. The expense associated with these plans is determined by management based on a number of assumptions and with consultation assistance from qualified third-party actuaries. The most important of these assumptions for the retirement plans involve the discount rate used to measure future plan obligations and the expected long-term rate of return on plan assets. For the retiree medical and insurance plans, the most important assumptions are the discount rate for future plan obligations and the health care cost trend rate. Discount rates are adjusted as necessary, generally based on the universe of high-quality corporate bonds available within each country, and after cash flow analyses are performed to discount projected benefit payment streams. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Anticipated health care cost trend rates are determined based on prior experience of the Company and an assessment of near-term and long-term trends for medical and drug costs.

  Based on bond yields at year-end 2008, the Company has used a discount rate of 6.50% in 2008 and beyond for the primary U.S. plans. Although the Company presently assumes a return on plan assets of 6.50% for the primary U.S. plan, it periodically reconsiders the appropriateness of this and other key assumptions. The smoothing effect of current accounting regulations tends to buffer the current year's pension expense from wide swings in liabilities and asset valuations. The Company's normal annual retirement and postretirement plan expenses are expected to increase slightly in 2009 compared to 2008 based on the effects of a growing employee base. In 2008, the Company paid $50.6 million into various retirement plans and $4.0 million into postretirement plans. In 2009, the Company is expecting to fund payments of approximately $50.2 million into various retirement plans and $4.9 million for postretirement plans. The 2009 retirement plan contribution includes a currently anticipated voluntary contribution of $30.0 million. The Company could be required to make additional and more significant funding payments to retirement plans in future years. Future required payments and the amount of liabilities recorded on the balance sheet associated with the plans could be unfavorably affected if the discount rate declines, the actual return on plan assets falls below the assumed 6.5%, or the health care cost trend rate increase is higher than expected. As described above, the Company's retirement and postretirement expenses are sensitive to certain assumptions, primarily related to discount rates and assumed return on plan assets. A 0.5% decline in the discount rate would increase 2009 annual retirement and postretirement expenses by $3.8 million and $0.6 million, respectively, and a 0.5% decline in the assumed rate of return on plan assets would increase 2009 retirement expense by $1.4 million.

- *Legal, environmental and other contingent matters* – A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and other contingent matters. In addition, the Company often must estimate the amount of such losses. In many cases, management's judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. The Company's management closely monitors known and potential legal, environmental and other contingent matters, and makes its best estimate of the amount of losses and when they should be recorded based on information available to the Company.

Contractual obligations and guarantees – The Company is obligated to make future cash payments under borrowing arrangements, operating leases, purchase obligations primarily associated with existing capital expenditure commitments, and other long-term liabilities. In addition, the Company expects to extend certain operating leases beyond the minimum contractual period. Total payments due after 2008 under such contractual obligations and arrangements are shown below.

	Amount of Obligation				
(Millions of dollars)	Total	2009	2010-2011	2012-2013	After 2013
Total debt including current maturities	$1,028.8	2.6	—	778.1	248.1
Operating leases	813.1	96.3	181.0	165.1	370.7
Purchase obligations	3,186.3	2,124.6	795.6	161.9	104.2
Other long-term liabilities	630.1	70.9	42.6	80.6	436.0
Total	$5,658.3	2,294.4	1,019.2	1,185.7	1,159.0

The Company has entered into an agreement to lease production facilities for the Kikeh field offshore Malaysia. In addition, the Company has other arrangements that call for future payments as described in the following section. The Company's share of the contractual obligations under these leases and other arrangements has been included in the table above.

In the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide financial guarantees or letters of credit that may be drawn upon if the Company fails to perform under those contracts. The amount of commitments as of December 31, 2008 that expire in future periods is shown below.

	Amount of Commitment				
(Millions of dollars)	Total	2009	2010-2011	2012-2013	After 2013
Financial guarantees	$ 7.8	—	—	—	7.8
Letters of credit	120.0	116.0	.6	—	3.4
Total	$127.8	116.0	.6	—	11.2

Material off-balance sheet arrangements – The Company occasionally utilizes off-balance sheet arrangements for operational or funding purposes. The most significant of these arrangements at year-end 2008 includes an operating lease of the Kikeh floating, production, storage and offloading vessel (FPSO), a natural gas transportation contract for the Tupper area in British Columbia and a hydrogen purchase contract for the Meraux refinery. The Kikeh FPSO lease calls for future monthly net lease payments over the next seven years. The Tupper transportation contract requires minimum monthly payments through 2013. The Meraux refinery contract to purchase hydrogen ends in 2021. The hydrogen contract requires a monthly minimum base facility charge whether or not any hydrogen is purchased. Future required minimum annual payments under these arrangements are included in the contractual obligation table shown above.

Outlook

Prices for the Company's primary products are often quite volatile. A strong global economy, which fueled demand for energy, led to generally stronger prices for crude oil and refined petroleum products during 2007 and the first half of 2008. Beginning in the second half of 2008 and continuing into early 2009, crude oil prices have fallen precipitously from the highs at mid-year 2008. The decline in the prices for crude oil is primarily attributable to softening demand for energy associated with the worldwide economic downturn. Due to the weak prices for crude oil and North American natural gas prices, the Company is making substantial efforts to balance its cash flow and spending in early 2009.

The Company's capital expenditure budget for 2009 was prepared during the fall of 2008 and based on this budget capital expenditures are expected to be below 2008 levels. Since the budget was approved by the Company's Board of Directors, crude oil and North American natural gas prices have generally been below the levels assumed in the 2009 budget. Based on a recent review of capital expenditure projects, capital expenditures in 2009 are projected to total approximately $2 billion. Of this amount, $1.7 billion or about 87%, is allocated for the exploration and production program. Geographically, E&P capital is spread approximately as follows: 16% for the United States, 42% for Malaysia, 23% for Canada and 19% for all other areas. Spending in the U.S. is primarily associated with continued development of producing and nonproducing deepwater fields as well as for the Company's Gulf of Mexico exploration program. In Malaysia, the majority of the spending is for continued development of natural gas fields in Blocks SK 309 and 311 offshore Sarawak where first production is anticipated in 2009 and the Kakap field in Block K. The bulk of Canadian spending in 2008 will relate to natural gas development at Tupper in Western Canada. Spending in the Republic of the Congo includes continuing development costs for the Azurite discovery offshore, which is scheduled to start production in mid-2009. Refining and marketing expenditures in 2009 should be about $250 million, including funds for construction of additional U.S. retail gasoline stations and early costs for an expansion of the crude unit at the Milford Haven, Wales refinery. Capital and other expenditures will be routinely reviewed during 2009 and planned capital expenditures may be adjusted to reflect differences between budgeted and actual cash flow during the year. Capital expenditures may also be affected by asset purchases, which often are not anticipated at the time the Budget is prepared.

The Company will primarily fund its capital program in 2009 using operating cash flow, but will supplement funding where necessary using borrowings under available credit facilities. The Company will endeavor to have no increase in long-term debt in 2009, but a continued low price environment could reduce actual cash flow generated from operations to such a level that borrowings might be required during the year to maintain funding of the Company's ongoing development projects. As noted earlier, crude oil and North American natural gas prices in early 2009 were well below the levels assumed in the 2009 budget. Also, through early 2009, margins within the Company's refining and marketing operations were generally below amounts included in the Company's 2009 budget.

The Company currently expects production in 2009 to average about 180,000 barrels of oil equivalent per day. A key assumption in projecting the level of 2009 Company production is the anticipated ramp up of natural gas production from Tupper in western Canada and Kikeh offshore Sabah Malaysia, and start-up of natural gas production offshore Sarawak Malaysia. In addition, continued reliability of production at significant fields such as Kikeh, Syncrude, Hibernia and Terra Nova are necessary to achieve the anticipated 2009 production levels.

Forward-Looking Statements

This Form 8-K contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. These statements, which express management's current views concerning future events or results, are subject to inherent risks and uncertainties. Factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements include, but are not limited to, the volatility and level of crude oil and natural gas prices, the level and success rate of our exploration programs, our ability to maintain production rates and replace reserves, political and regulatory instability, and uncontrollable natural hazards. For further discussion of risk factors, see Item 1A. Risk Factors beginning on page 7 of the 2008 Form 10-K. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

Exhibit 99.3

Murphy Oil Corporation and Consolidated Subsidiaries

Restated Consolidated Financial Statements

For the Three-Year Period Ended
December 31, 2008, 2007 and 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of Murphy Oil Corporation:

We have audited the accompanying consolidated balance sheets of Murphy Oil Corporation and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of income, comprehensive income, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2008. In connection with our audits of the consolidated financial statements, we also have audited financial statement Schedule II. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the Standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Murphy Oil Corporation and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note B to the consolidated financial statements, effective December 31, 2006, the Company changed its accounting for recognition of defined benefit pension and other postretirement plans. As also discussed in Note B to the consolidated financial statements, effective January 1, 2007, the Company changed its accounting for uncertain tax positions, and measurement of defined benefit pension and other postretirement plans.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Murphy Oil Corporation's internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2009 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Houston, Texas
February 27, 2009, except for the effects
of discontinued operations, as discussed
in Note C, which is as of September 2, 2009.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(As Adjusted – See Note C)

Years Ended December 31 (Thousands of dollars except per share amounts)	2008	2007	2006
Revenues			
Sales and other operating revenues	$ 27,360,625	18,297,637	14,156,666
Gain (loss) on sale of assets	133,717	(365)	9,388
Interest and other income (loss)	(62,011)	15,692	15,208
Total revenues	27,432,331	18,312,964	14,181,262
Costs and Expenses			
Crude oil and product purchases	21,649,742	14,882,618	11,214,235
Operating expenses	1,657,427	1,274,858	1,063,601
Exploration expenses, including undeveloped lease amortization	344,406	202,808	217,773
Selling and general expenses	228,490	228,316	227,399
Depreciation, depletion and amortization	667,265	450,624	356,730
Impairment of properties	—	40,708	—
Accretion of asset retirement obligations	24,484	16,244	10,921
Net costs associated with hurricanes	—	3,000	109,244
Interest expense	73,611	74,665	52,549
Interest capitalized	(31,459)	(49,881)	(43,073)
Total costs and expenses	24,613,966	17,123,960	13,209,379
Income from continuing operations before income taxes	2,818,365	1,189,004	971,883
Income tax expense	1,073,616	449,924	368,833
Income from continuing operations	1,744,749	739,080	603,050
Income (loss) from discontinued operations, net of income taxes	(4,763)	27,449	41,619
Net Income	$ 1,739,986	766,529	644,669
Income per Common Share – Basic			
Income from continuing operations	$ 9.20	3.93	3.24
Income (loss) from discontinued operations	(.02)	.15	.22
Net Income – Basic	$ 9.18	4.08	3.46
Income per Common Share – Diluted			
Income from continuing operations	$ 9.08	3.87	3.19
Income (loss) from discontinued operations	(.02)	.14	.22
Net Income – Diluted	$ 9.06	4.01	3.41
Average Common shares outstanding – basic	189,608,846	188,027,557	186,105,086
Average Common shares outstanding – diluted	192,133,672	191,140,737	189,158,411

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

December 31 *(Thousands of dollars)*	2008	2007
Assets		
Current assets		
Cash and cash equivalents	$ 666,110	673,707
Canadian government securities with maturities greater than 90 days at the date of acquisition	420,340	—
Accounts receivable, less allowance for doubtful accounts of $7,303 in 2008 and $7,484 in 2007	1,033,996	1,420,601
Inventories, at lower of cost or market		
Crude oil and blend stocks	98,217	159,379
Finished products	315,340	315,977
Materials and supplies	190,616	151,291
Prepaid expenses	92,544	79,585
Deferred income taxes	29,801	86,252
Total current assets	2,846,964	2,886,792
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $3,824,393 in 2008 and $3,516,338 in 2007	7,727,718	7,109,822
Goodwill	37,370	51,450
Deferred charges and other assets	537,046	487,785
Total assets	$ 11,149,098	10,535,849
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long-term debt	$ 2,572	5,208
Notes payable	—	7,561
Accounts payable	1,174,623	1,662,401
Income taxes payable	451,372	108,783
Other taxes payable	152,038	199,809
Other accrued liabilities	107,541	125,500
Total current liabilities	1,888,146	2,109,262
Notes payable	1,026,222	1,513,015
Nonrecourse debt of a subsidiary	—	3,141
Deferred income taxes	878,131	916,910
Asset retirement obligations	435,589	336,107
Deferred credits and other liabilities	642,065	591,240
Stockholders' equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued	—	—
Common Stock, par $1.00, authorized 450,000,000 shares at December 31, 2008 and 2007, issued 191,248,941 shares at December 31, 2008 and 189,972,970 shares at December 31, 2007	191,249	189,973
Capital in excess of par value	631,859	547,185
Retained earnings	5,557,483	3,983,998
Accumulated other comprehensive income	(87,697)	351,765
Treasury stock	(13,949)	(6,747)
Total stockholders' equity	6,278,945	5,066,174
Total liabilities and stockholders' equity	$ 11,149,098	10,535,849

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(As Adjusted – See Note C)

Years Ended December 31 *(Thousands of dollars)*	2008	2007	2006
Operating Activities			
Net income	$ 1,739,986	766,529	644,669
(Income) loss from discontinued operations	4,763	(27,449)	(41,619)
Income from continuing operations	1,744,749	739,080	603,050
Adjustments to reconcile income from continuing operations to net cash provided by operating activities			
Depreciation, depletion and amortization	667,265	450,624	356,730
Impairment of long-lived assets	—	40,708	—
Amortization of deferred major repair costs	27,294	22,107	17,720
Expenditures for asset retirements	(9,240)	(13,039)	(3,328)
Dry hole costs	129,459	66,797	109,579
Amortization of undeveloped leases	112,052	33,215	22,466
Accretion of asset retirement obligations	24,484	16,244	10,921
Deferred and noncurrent income tax charges	233,076	102,507	33,091
Pretax (gains) losses from disposition of assets	(133,717)	365	(9,388)
Net decrease (increase) in noncash operating working capital	93,710	145,454	(254,470)
Other operating activities – net	35,304	69,441	20,190
Net cash provided by continuing operations	2,924,436	1,673,503	906,561
Net cash provided by discontinued operations	115,476	66,917	68,917
Net cash provided by operating activities	3,039,912	1,740,420	975,478
Investing Activities			
Property additions and dry hole costs	(2,179,011)	(1,908,803)	(1,156,877)
Acquisition of Milford Haven refinery, including inventory	—	(348,292)	—
Proceeds from sale of property, plant and equipment	361,961	21,636	23,843
Expenditures for major repairs	(57,604)	(14,649)	(12,776)
Purchase of investment securities*	(1,043,473)	—	—
Proceeds from maturity of investment securities*	623,133	—	—
Other investing activities – net	(21,256)	4,011	(10,839)
Investing activities of discontinued operations	(6,949)	(40,416)	(34,793)
Net cash required by investing activities	(2,323,199)	(2,286,513)	(1,191,442)
Financing Activities			
Additions to notes payable	—	686,194	237,658
Reductions of notes payable	(487,612)	(825)	(14)
Reductions of nonrecourse debt of a subsidiary	(5,235)	(4,903)	(4,667)
Proceeds from exercise of stock options and employee stock purchase plans	29,687	41,624	24,864
Excess tax benefits related to exercise of stock options	20,288	30,805	11,756
Cash dividends paid	(166,501)	(127,353)	(98,162)
Other financing activities – net	—	(760)	—
Net cash provided (required) by financing activities	(609,373)	624,782	171,435
Effect of exchange rate changes on cash and cash equivalents	(114,937)	51,628	2,586
Net increase (decrease) in cash and cash equivalents	(7,597)	130,317	(41,943)
Cash and cash equivalents at January 1	673,707	543,390	585,333
Cash and cash equivalents at December 31	$ 666,110	673,707	543,390

* Represents cash invested in Canadian government securities with maturities greater than 90 days at the date of acquisition.

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

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

Years Ended December 31 *(Thousands of dollars)*	2008	2007	2006
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	—	—	—
Common Stock – par $1.00, authorized 450,000,000 shares at December 31, 2008, 2007 and 2006, issued 191,248,941 shares at December 31, 2008, 189,972,970 shares at December 31, 2007, and 187,691,508 shares at December 31, 2006			
Balance at beginning of year	$ 189,973	187,692	186,829
Exercise of stock options	1,276	2,281	863
Balance at end of year	191,249	189,973	187,692
Capital in Excess of Par Value			
Balance at beginning of year	547,185	454,860	437,963
Exercise of stock options, including income tax benefits	45,839	63,702	23,956
Restricted stock transactions and other	7,089	3,794	(1,390)
Amortization, forfeitures and other	30,811	23,784	10,180
Sale of stock under employee stock purchase plans	935	1,045	561
Reclassification from Unamortized Restricted Stock Awards upon adoption of SFAS No. 123R	—	—	(16,410)
Balance at end of year	631,859	547,185	454,860
Retained Earnings			
Balance at beginning of year	3,983,998	3,349,832	2,803,325
Cumulative effect of changes in accounting principles	—	(5,010)	—
Net income for the year	1,739,986	766,529	644,669
Cash dividends – $.875 per share in 2008, $.675 per share in 2007 and $.525 per share in 2006	(166,501)	(127,353)	(98,162)
Balance at end of year	5,557,483	3,983,998	3,349,832
Accumulated Other Comprehensive Income			
Balance at beginning of year	351,765	131,999	133,353
Cumulative effect of changes in accounting principles	—	1,345	—
Foreign currency translation gains (losses), net of income taxes	(383,021)	204,266	37,143
Cash flow hedging gains, net of income taxes	—	—	13,459
Retirement and postretirement benefit plan adjustments, net of income taxes	(56,441)	14,155	(819)
Adjustment to initially apply SFAS No. 158, net of income taxes	—	—	(51,137)
Balance at end of year	(87,697)	351,765	131,999
Unamortized Restricted Stock Awards			
Balance at beginning of year	—	—	(16,410)
Reclassification to Capital in Excess of Par Value upon adoption of SFAS No. 123R	—	—	16,410
Balance at end of year	—	—	—
Treasury Stock			
Balance at beginning of year	(6,747)	(3,110)	(22,990)
Exercise of stock options	—	—	13,345
Sale of stock under employee stock purchase plans	515	982	737
Awarded restricted stock, net of forfeitures	(7,717)	(4,619)	5,798
Balance at end of year – 535,135 shares of Common Stock in 2008, 258,821 shares in 2007 and 119,308 shares in 2006	(13,949)	(6,747)	(3,110)
Total Stockholders' Equity	$6,278,945	5,066,174	4,121,273

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(Thousands of dollars)*	2008	2007	2006
Net income	$1,739,986	766,529	644,669
Other comprehensive income (loss), net of tax			
Cash flow hedges			
Net derivative losses	—	—	(5,154)
Reclassification to income	—	—	18,613
Total cash flow hedges	—	—	13,459
Net gain (loss) from foreign currency translation	(383,021)	204,266	37,143
Retirement and postretirement plan adjustments	(56,441)	14,155	(819)
Other comprehensive income (loss)	(439,462)	218,421	49,783
Comprehensive Income	$1,300,524	984,950	694,452

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

Note A – Significant Accounting Policies

NATURE OF BUSINESS – Murphy Oil Corporation is an international oil and gas company that conducts its business through various operating subsidiaries. The Company produces oil and/or natural gas in the United States, Canada, the United Kingdom, Malaysia and Ecuador and conducts oil and natural gas exploration activities worldwide. The Company has an interest in a Canadian synthetic oil operation, owns two petroleum refineries in the United States and one refinery in the United Kingdom. Murphy markets petroleum products under various brand names and to unbranded wholesale customers in the United States and United Kingdom.

PRINCIPLES OF CONSOLIDATION – The consolidated financial statements include the accounts of Murphy Oil Corporation and all majority-owned subsidiaries. For consolidated subsidiaries that are less than wholly owned, the noncontrolling interest is reflected in the balance sheet as a component of Stockholders' Equity. Undivided interests in oil and gas joint ventures are consolidated on a proportionate basis. Investments in affiliates in which the Company owns from 20% to 50% are accounted for by the equity method. Other investments are generally carried at cost. All significant intercompany accounts and transactions have been eliminated.

REVENUE RECOGNITION – Revenues from sales of crude oil, natural gas and refined petroleum products are recorded when deliveries have occurred and legal ownership of the commodity transfers to the customer. Title transfers for crude oil, natural gas and bulk refined products generally occur at pipeline custody points or when a tanker lifting has occurred. Refined products sold at retail are recorded when the customer takes delivery at the pump. Merchandise revenues are recorded at the point of sale. Revenues from the production of oil and natural gas properties in which Murphy shares an undivided interest with other producers are recognized based on the actual volumes sold by the Company during the period. Gas imbalances occur when the Company's actual sales differ from its entitlement under existing working interests. The Company records a liability for gas imbalances when it has sold more than its working interest of gas production and the estimated remaining reserves make it doubtful that partners can recoup their share of production from the field. At December 31, 2008 and 2007, the liabilities for natural gas balancing were immaterial.

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

TAXES COLLECTED FROM CUSTOMERS AND REMITTED TO GOVERNMENT AUTHORITIES – Excise and other taxes collected on sales of refined products and remitted to governmental agencies are excluded from revenues and costs and expenses in the Consolidated Statement of Income.

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

MARKETABLE SECURITIES – The Company classifies investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities. The Company does not have any investments classified as trading. Available-for-sale securities are carried at fair value with the unrealized gain or loss, net of tax, reported in other comprehensive income. Held-to-maturity securities are recorded at amortized cost. Premiums and discounts are amortized or accreted into earnings over the life of the related available-for-sale or held-to-maturity security. Dividend and interest income is recognized when earned. Unrealized losses considered to be "other than temporary" are recognized currently in earnings. The cost of securities sold is based on the specific identification method. The fair value of investment securities is determined by available market prices. At December 31, 2008, the Company owned Canadian government securities with maturities greater than 90 days at date of acquisition that had a carrying value of $420,340,000.

ACCOUNTS RECEIVABLE – The Company's accounts receivable primarily consists of amounts owed to the Company by customers for sales of crude oil, natural gas and refined products under varying credit arrangements. The allowance for doubtful accounts is the Company's best estimate of the amount of probable credit losses on these receivables. The Company reviews this allowance for adequacy at least quarterly and bases its assessment on a combination of current information about its customers and historical write-off experience.

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

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

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

Depreciation and depletion of producing oil and gas properties is recorded based on units of production. Unit rates are computed for unamortized exploration drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. Asset retirement costs are amortized over proved reserves using the units of production method. As more fully described on page F-34 of this Form 8-K report, proved reserves are estimated by the Company's engineers and are subject to future revisions based on availability of additional information. Refineries and certain marketing facilities are depreciated primarily using the composite straight-line method with depreciable lives ranging from 14 to 25 years. Gasoline stations and other properties are depreciated over 3 to 20 years by individual unit on the straight-line method. Gains and losses on asset disposals or retirements are included in income as a separate component of revenues.

Turnarounds for major processing units are scheduled at four to five year intervals at the Company's three refineries. Turnarounds for coking units at Syncrude Canada Ltd. are scheduled at intervals of two to three years. Turnaround work associated with various other less significant units at the Company's refineries and Syncrude will vary depending on operating requirements and events. Murphy defers turnaround costs incurred and amortizes such costs through Operating Expenses over the period until the next scheduled turnaround. All other maintenance and repairs are expensed as incurred. Renewals and betterments are capitalized.

INVENTORIES – Unsold crude oil production is carried in inventory at the lower of cost, generally applied on a first-in, first-out (FIFO) basis, or market, and include costs incurred to bring the inventory to its existing condition. Refinery inventories of crude oil and other feedstocks and finished product inventories are valued at the lower of cost, generally applied on a last-in, first-out (LIFO) basis, or market. Inventory held for resale at retail marketing stations is generally carried at average cost and is included in Finished Products Inventory. Materials and supplies are valued at the lower of average cost or estimated value and generally consist of tubulars and other drilling equipment as well as spare parts for refinery operations. Cash collected upon the sale of inventory to customers is classified as an operating activity in the Consolidated Statement of Cash Flows.

GOODWILL – Goodwill is recorded in an acquisition when the purchase price exceeds the fair value of net assets acquired. All recorded goodwill arose from the purchase of Beau Canada Exploration Ltd. by the Company's wholly owned Canadian subsidiary in 2000. In accordance with SFAS No. 142, Goodwill and Other Intangible Assets, goodwill is not amortized. SFAS No. 142 requires an annual assessment of recoverability of the carrying value of goodwill. The Company assesses goodwill recoverability at each year-end by comparing the fair value of net assets for conventional oil and natural gas properties in Canada with the carrying value of these net assets including goodwill. The fair value of the conventional oil and natural gas reporting unit is determined using the expected present value of future cash flows. The change in the carrying value of goodwill during 2008 was caused by a change in the foreign currency translation rate between years and sale of certain assets in Canada during the year. Based on its assessment of the fair value of its Canadian conventional oil and natural gas operations, the Company believes the recorded value of goodwill is not impaired at December 31, 2008. Should a future assessment indicate that goodwill is not fully recoverable, an impairment charge to write down the carrying value of goodwill would be required.

ENVIRONMENTAL LIABILITIES – A liability for environmental matters is established when it is probable that an environmental obligation exists and the cost can be reasonably estimated. If there is a range of reasonably estimated costs, the most likely amount will be recorded, or if no amount is most likely, the minimum of the range is used. Related expenditures are charged against the liability. Environmental remediation liabilities have not been discounted for the time value of future expected payments. Environmental expenditures that have future economic benefit are capitalized.

INCOME TAXES – The Company accounts for income taxes using the asset and liability method. Under this method, income taxes are provided for amounts currently payable and for amounts deferred as tax assets and liabilities based on differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities. Deferred income taxes are measured using the enacted tax rates that are assumed will be in effect when the differences reverse. Petroleum revenue taxes are provided using the estimated effective tax rate over the life of applicable U.K. properties. The Company uses the deferral method to account for Canadian investment tax credits associated with the Hibernia and Terra Nova oil fields. As described in Notes B and I, the Company adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, as of January 1, 2007. This guidance permits recognition of income tax benefits only when they are more likely than not to be realized. The Company includes potential penalties and interest for uncertain income tax positions in income tax expense.

FOREIGN CURRENCY – Local currency is the functional currency used for recording operations in Canada and Spain and for refining and marketing activities in the United Kingdom. The U.S. dollar is the functional currency used to record all other operations. Exchange gains or losses from transactions in a currency other than the functional currency are included in earnings. Gains or losses from translating foreign functional currency into U.S. dollars are included in Accumulated Other Comprehensive Income in Stockholders' Equity.

DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES – The Company accounts for derivative instruments and hedging activity under SFAS No. 133, as amended by SFAS Nos. 138 and 149. The fair value of a derivative instrument is recognized as an asset or liability in the Company's Consolidated Balance Sheet. Upon entering into a derivative contract, the Company may designate the derivative as either a fair value hedge or a cash flow hedge, or decide that the contract is not a hedge, and thenceforth, recognize changes in the fair value of the contract in earnings. The Company documents the relationship between the derivative instrument designated as a hedge and the hedged items as well as its objective for risk management and strategy for use of the hedging instrument to manage the risk. Derivative instruments designated as fair value or cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. The Company assesses at inception and on an ongoing basis whether a derivative instrument used as a hedge is highly effective in offsetting changes in the fair value or cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting. Changes in the fair value of a qualifying fair value hedge are recorded in earnings along with the gain or loss on the hedged item. Changes in the fair value of a qualifying cash flow hedge are recorded in other comprehensive income until the hedged item is recognized in earnings. When the income effect of the underlying cash flow hedged item is recognized in the Statement of Income, the fair value of the associated cash flow hedge is reclassified from other comprehensive income into earnings. Ineffective portions of a cash flow hedge derivative's change in fair value are recognized currently in earnings. If a derivative instrument no longer qualifies as a cash flow hedge and the underlying forecasted transaction is no longer probable of occurring, hedge accounting is discontinued and the gain or loss recorded in other comprehensive income is recognized immediately in earnings.

NET INCOME PER COMMON SHARE – Basic income per Common share is computed by dividing net income for each reporting period by the weighted average number of Common shares outstanding during the period. Diluted income per Common share is computed by dividing net income for each reporting period by the weighted average number of Common shares outstanding during the period plus the effects of all potentially dilutive Common shares.

STOCK-BASED COMPENSATION – Under SFAS No. 123R, Share-Based Payment, the fair value of awarded stock options, restricted stock and restricted stock units is determined using a fair value based on a combination of management assumptions and the market value of the Company's common stock. The Company uses the Black-Scholes option pricing model for computing the fair value of stock options. The primary assumptions made by management include the expected life of the stock option award and the expected volatility of Murphy's common stock prices. The Company uses both historical data and current information to support its assumptions. Stock option expense is recognized on a straight-line basis over the respective vesting period of two or three years. The Company uses a Monte Carlo valuation model to determine the fair value of performance-based restricted stock and restricted stock units and expense is recognized over the three-year vesting period. The fair value of time-lapse restricted stock is determined based on the price of Company stock on the date of grant and is recognized over the vesting period. The Company estimates the number of stock options and performance-based restricted stock and restricted stock units that will not vest and adjusts its compensation expense accordingly. Differences between estimated and actual vested amounts are accounted for when known.

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

Note B – New Accounting Principles and Recent Accounting Pronouncements

New Accounting Principles Adopted

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement applies under other accounting pronouncements that require or permit fair value measurements, and where applicable simplifies and codifies related guidance within GAAP and does not require any new fair value measurements. The statement was originally effective for fiscal years beginning January 1, 2008. On February 12, 2008, the FASB issued FSP No. 157-2 that delayed for one year the effective date of SFAS No. 157 for most nonfinancial assets and nonfinancial liabilities. Provisions of the statement are to be applied prospectively except in limited situations. The Company adopted this statement as of January 1, 2008 and the adoption had no material impact on its consolidated financial statements. See further disclosures at Note O.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS No. 159). This pronouncement permits companies with eligible financial assets and financial liabilities to measure these items at fair value in the financial statements. This option to measure at fair value is both instrument specific and irrevocable. If the fair value option is elected, certain additional disclosures are required and financial statements for periods prior to the adoption may not be restated. The Company adopted this standard as of January 1, 2008, but the Company chose not to elect fair value measurement for any financial assets and financial liabilities, and therefore, the adoption of SFAS No. 159, had no impact on the Company's consolidated balance sheet or consolidated statement of income.

In June 2007, the FASB ratified the Emerging Issues Task Force's Issue No. 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards (EITF No. 06-11). This new guidance was effective for the Company beginning in January 2008 and required that income tax benefits received by the Company for dividends paid on share-based incentive awards be recorded in Capital in Excess of Par Value in Stockholders' Equity. Under certain circumstances, such tax benefits received on awards that do not vest could be reclassified to reduce income tax expense in the Consolidated Statements of Income. The effect of adopting EITF No. 06-11 in 2008 was not material to the Company's consolidated financial statements.

In September 2006, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of SFAS Nos. 87, 88, 106 and 132R (SFAS No. 158). This statement requires the Company to recognize in its consolidated balance sheet the overfunded or underfunded status of its defined benefit plans as an asset or liability and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This statement also requires that the Company measure the funded status of a plan as of December 31 rather than September 30 as previously permitted. The Company implemented this statement as to recognition of funded status as of December 31, 2006 and as to the year-end measurement date as of January 1, 2007. The adoption of the year-end measurement portion of this statement led to an adjustment to reduce Retained Earnings as of January 1, 2007 by $4,301,000. Refer to Note K for further information.

In June 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48). This interpretation clarifies the criteria for recognizing income tax benefits under FASB Statement No. 109, Accounting for Income Taxes, and requires additional financial statement disclosures about uncertain tax positions. Effective January 1, 2007, the Company adopted FIN 48. Under FIN 48 the financial statement recognition of the benefit for a tax position is dependent upon the benefit being more likely than not to be sustainable upon audit by the applicable taxing authority. If this threshold is met, the tax benefit is then measured and recognized at the largest amount that is greater than 50 percent likely of being realized upon ultimate settlement. Upon adoption of FIN 48, the Company recognized a $709,000 increase in its liability for unrecognized income tax benefits, which is included in Deferred Credits and Other Liabilities in the Consolidated Balance Sheet, and it recognized a similar decrease to Retained Earnings. Refer to Note I for further information.

Recent Accounting Pronouncements

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51. This statement is effective for the Company beginning January 1, 2009. Upon adoption, this statement will require noncontrolling interests to be reclassified as equity, and consolidated net income and comprehensive income shall include the respective results attributable to noncontrolling interests. It is to be applied prospectively and early adoption is not permitted. The Company does not expect this statement to have a significant effect on its consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations. This statement establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquired business. It also establishes how to recognize and measure goodwill acquired in the business combination or a gain from a bargain purchase, if applicable. This statement shall be applied prospectively by the Company to any business combination that occurs on or after January 1, 2009. Early application is prohibited. Assets and liabilities that arise from business combinations occurring prior to 2009 shall not be adjusted upon application of this statement. This statement will impact the recognition and measurement of assets and liabilities in business combinations that occur after 2008, and the Company is unable to predict at this time how the application of this statement will affect its financial statements in future periods.

In March 2008, the FASB issued SFAS No. 161, Disclosure about Derivative Instruments and Hedging Activities. This statement is effective for the Company beginning in January 2009, and it expands required disclosures regarding derivative instruments to include qualitative information about objectives and strategies for using derivatives, quantities disclosures about fair value amounts and gains and losses on derivative instruments, and disclosures about credit-risk related contingent features in derivative agreements. The Company does not expect this statement to have a significant effect on its consolidated financial statements.

In June 2008, the FASB issued FASB Staff Position on EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities (FSP EITF 03-6-1). This statement provides that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings per share (EPS) calculation under the two-class method. All prior-period EPS calculations must be adjusted retrospectively. This statement is effective for the Company in 2009. Although the Company is in the process of evaluating this statement, it does not expect the effect of adopting this statement in 2009 to have a significant impact on its prior-period EPS calculations.

In December 2008, the FASB issued Staff Position No. FAS 132(R)-1, Employers' Disclosures about Postretirement Benefit Plan Assets. This guidance will require additional disclosures about benefit plan assets, including how asset investment allocation decisions are made, the fair value of each major category of plan assets, and how fair value is determined for each major asset category. This guidance is effective for the Company at year-end 2009. Upon adoption, no comparative disclosures are required for earlier years presented. The Company does not expect the adoption of this standard to have a material impact on its consolidated financial statements in future periods.

In November 2008, the EITF published Issue No. 08-6, Equity Method Investment Accounting Considerations. This pronouncement gives guidance about how to initially measure contingent consideration for an equity method investment, how to recognize other-than-temporary impairments of an equity method investment, and how an equity method investor is to account for a share issuance by an investee. This guidance is effective for the Company at the beginning of its 2009 fiscal year. The guidance is to be applied prospectively and early adoption is not permitted. The Company is currently evaluating this guidance and is unable to predict at this time how it will impact its consolidated financial statements in future periods.

Note C – Subsequent Event, Discontinued Operations and Adjustments to Consolidated Financial Statements.

On March 12, 2009, the Company sold its operations in Ecuador for net cash proceeds of $78.9 million, subject to post-closing adjustments. The acquiror also assumed certain tax and other liabilities associated with the Ecuador properties sold. The Ecuador properties sold included 20% interests in producing areas, including Block 16 and the nearby Tivacuno field. Ecuador operating results prior to the sale have been reported as discontinued operations for all periods presented. The consolidated financial statements for 2008 and prior years have been adjusted to conform to this presentation. The financial information contained in the financial statements and accompanying consolidated notes to the financial statements reflect only the adjustments described above. No other modifications or updates to these disclosures for events that occurred after February 27, 2009, the date of the filing of our 2008 Form 10-K, have been made in this Current Report on Form 8-K.

The following table reflects the results of operations from the Ecuador properties sold in 2009.

(Thousands of dollars)	2008	2007	2006
Revenues	80,209	126,134	126,125
Income before income tax expense	188	48,228	66,515
Income tax expense	4,951	20,779	24,896

Note D – Milford Haven Refinery Acquisition

On December 1, 2007, Murphy Oil's indirect wholly-owned subsidiary, Murco Petroleum Limited (Murco), acquired the remaining 70% interest in the Milford Haven, Wales, refinery in the U.K. Prior to the acquisition, Murco held an effective 30% interest in the 108,000 barrel per day refinery located in Pembrokeshire in southwest Wales. Post-acquisition, Murco owns 100% of the refinery. Murco paid cash consideration for the refinery complex, certain nearby land, the adjacent jetty, a pipeline connection to the Mainline Pipeline and spare parts. Murco also obtained the refinery workforce and primary operational systems, and purchased certain crude oil and products inventory at the time of acquisition. The total purchase price of $348,292,000 included $11,078,000 of transaction costs. Revenue and expenses associated with the 70% interest acquired have been included in the Company's consolidated financial statements beginning on December 1, 2007. No goodwill was recorded associated with this acquisition as the fair value of the assets acquired exceeded the purchase price paid by the Company.

Note E – Property, Plant and Equipment

	December 31, 2008		December 31, 2007	
(Thousands of dollars)	Cost	Net	Cost	Net
Exploration and production[1]	$ 8,485,391	5,791,945[2]	7,748,041	5,316,671[2]
Refining	1,649,679	881,436	1,665,807	922,443
Marketing	1,337,223	1,008,703	1,133,788	822,580
Corporate and other	79,818	45,634	78,524	48,128
	$ 11,552,111	7,727,718	10,626,160	7,109,822
[1] Includes mineral rights as follows:	$ 536,884	374,646	461,974	377,307

[2] Includes $13,983 in 2008 and $13,730 in 2007 related to administrative assets and support equipment.

On December 1, 2006, the Company exchanged its interest in the Rimbey field in western Canada for an 80% interest in the common stock of Berkana Energy Corporation (Berkana). The Company recorded a $9,909,000 pretax gain in 2006 associated with the Rimbey exchange. The transaction was accounted for as a reverse acquisition. In January 2008, the Company sold its interest in Berkana Energy Corporation and recorded a pretax gain of $41,950,000 ($40,161,000 after-tax). In May 2008, the Company sold its interest in the Lloydminster area properties in Western Canada for a pretax gain of $90,451,000 ($67,236,000 after-tax).

In 2007, the Company entered into an agreement with Walmart Stores, Inc. to purchase parcels of property leased from Walmart for its Murphy USA retail gasoline stations. A total of 835 sites have been purchased at a cost of $304,200,000. In conjunction with purchasing these sites, the Company closed 55 stations in the U.S. and Canada in 2007. In the Consolidated Statement of Income for 2007, the Company recorded noncash impairment charges of $40,708,000 primarily for writedown of the remaining book value and associated abandonment costs related to the North American retail gasoline station closures.

The FASB issued FSP 19-1 to provide guidance on accounting for exploratory well costs and to amend SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies (SFAS No. 19). The guidance in FSP 19-1 applies to companies that use the successful efforts method of accounting as described in SFAS No. 19. This FSP clarifies that exploratory well costs should continue to be capitalized when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The guidance in this FSP was applied on a prospective basis beginning in April 2005 to existing and newly-capitalized exploratory well costs.

At December 31, 2008, 2007 and 2006, the Company had total capitalized drilling costs pending the determination of proved reserves of $310,118,000, $272,155,000 and $315,445,000, respectively. The following table reflects the net changes in capitalized exploratory well costs during the three-year period ended December 31, 2008.

(Thousands of dollars)	2008	2007	2006
Beginning balance at January 1	$272,155	315,445	275,256
Additions to capitalized exploratory well costs pending the determination of proved reserves	44,832	6,856	158,234
Reclassifications to proved properties based on the determination of proved reserves	(6,869)	(50,146)	(114,614)
Capitalized exploratory well costs charged to expense or sold	—	—	(3,431)
Ending balance at December 31	$310,118	272,155	315,445

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of projects for which exploratory well costs have been capitalized since the completion of drilling.

	2008			2007			2006		
(Thousands of dollars)	Amount	No. of Wells	No. of Projects	Amount	No. of Wells	No. of Projects	Amount	No. of Wells	No. of Projects
Aging of capitalized well costs:									
Zero to one year	$ 48,424	4	4	$ 8,851	10	1	$122,399	25	5
One to two years	8,870	7	—	101,120	19	4	107,212	10	2
Two to three years	101,151	18	4	87,393	8	2	73,681	10	3
Three years or more	151,673	14	4	74,791	8	2	12,153	1	1
	$310,118	43	12	$272,155	45	9	$315,445	46	11

Of the $261,694,000 of exploratory well costs capitalized more than one year, $169,283,000 is in Malaysia, $60,251,000 is in the Republic of the Congo, $27,633,000 is in the U.S., and $4,527,000 is in Canada. In Malaysia either further appraisal or development drilling is planned and/or development studies/plans are in various stages of completion. In the Republic of the Congo a development program is underway for the offshore Azurite field with first oil production expected in 2009. In the U.S. further drilling is anticipated and development plans are being formulated, and in Canada a continuing drilling and development program is underway.

Note F – Financing Arrangements

At December 31, 2008, the Company had a $1,962,500,000 committed credit facility with a major banking consortium that matures in June 2012. Between June 2010 and June 2011, the capacity of the committed facility is reduced to $1,905,000,000 and between June 2011 and June 2012 the maximum facility is $1,827,500,000. At December 31, 2008, the Company had borrowed $318,500,000 under this committed facility. Borrowings under this facility bear interest at prime or varying cost of fund options. Facility fees are due at varying rates on the commitment. At December 31, 2008 the Company had borrowed $110,000,000 under uncommitted credit lines. If necessary, the Company could convert borrowings under these uncommitted lines to the committed long-term credit facility outstanding through 2012. The Company's shelf registration statement on file with the U.S. Securities and Exchange Commission that permitted the offer and sale of up to $650,000,000 in debt and/or equity securities expired on December 31, 2008. The Company expects to file a new shelf registration in the second quarter of 2009.

Note G – Long-term Debt

(Thousands of dollars)	December 31 2008	2007
Notes payable		
6.375% notes, due 2012, net of unamortized discount of $384 at December 31, 2008	$ 349,616	349,501
7.05% notes, due 2029, net of unamortized discount of $1,894 at December 31, 2008	248,106	248,014
Notes payable to banks, 0.925% to 3.20% at December 31, 2008	428,500	915,500
Total notes payable	1,026,222	1,513,015
Nonrecourse debt of a subsidiary		
Loans payable to Canadian government, interest free, payable in Canadian dollars, due 2009	2,572	8,349
Total debt including current maturities	1,028,794	1,521,364
Current maturities	(2,572)	(5,208)
Total long-term debt	$1,026,222	1,516,156

Maturities for the four years after 2009 are: nil in 2010 and 2011, $778,116,000 in 2012 and nil in 2013.

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

Note H – Asset Retirement Obligations

The majority of the asset retirement obligations (ARO) recognized by the Company at December 31, 2008 and 2007 related to the estimated costs to dismantle and abandon its producing oil and gas properties and related equipment. A portion of the ARO relates to retail gasoline stations. The Company did not record an ARO for its refining and certain of its marketing assets because sufficient information is presently not available to estimate a range of potential settlement dates for the obligation. These assets are consistently being upgraded and are expected to be operational into the foreseeable future. In these cases, the obligation will be initially recognized in the period in which sufficient information exists to estimate the obligation.

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

(Thousands of dollars)	2008	2007
Balance at beginning of year	$336,107	237,875
Accretion expense	24,484	16,244
Liabilities incurred	46,367	50,686
Revision of previous estimates	68,245	29,103
Liabilities settled	(23,335)*	(13,039)
Changes due to translation of foreign currencies	(16,279)	15,238
Balance at end of year	$435,589	336,107

* Includes non-cash settlements related to sale of assets in Canada in 2008.

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

Note I – Income Taxes

The components of income from continuing operations before income taxes for each of the three years ended December 31, 2008 and income tax expense (benefit) attributable thereto were as follows.

(Thousands of dollars)	2008	2007	2006
Income from continuing operations before income taxes			
United States	$ 476,882	415,124	339,426
Foreign	2,341,483	773,880	632,457
	$2,818,365	1,189,004	971,883
Income tax expense (benefit)			
Federal – Current	$ 134,759	82,033	120,591
– Deferred	40,328	56,407	(8,210)
	175,087	138,440	112,381
State	16,714	15,969	2,245
Foreign – Current*	689,407	248,301	216,457
– Deferred*	192,408	47,214	37,750
	881,815	295,515	254,207
Total	$1,073,616	449,924	368,833

* Includes benefits of $38,687 in 2007 and $37,554 in 2006 for enacted reductions in federal and provincial tax rates in Canada. Tax expense in 2006 includes a charge of $17,845 for an enacted increase in income tax rate for exploration and production operations in the U.K.

Income tax benefits attributable to employee stock option transactions of $22,495,000 in 2008, $33,895,000 in 2007 and $13,680,000 in 2006 were included in Capital in Excess of Par Value in the Consolidated Balance Sheets. Income tax charges of $5,398,000 in 2006 relating to derivatives were included in Accumulated Other Comprehensive Income (AOCI).

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

(Thousands of dollars)	2008	2007	2006
Income tax expense based on the U.S. statutory tax rate	$ 986,428	416,151	340,159
Foreign income subject to foreign taxes at a rate different than the U.S. statutory rate	19,823	32,021	21,371
State income taxes, net of federal benefit	10,864	10,380	1,459
Changes in foreign tax rates	—	(38,687)	(19,709)
Increase in deferred tax asset valuation allowance related to foreign exploration expenditures	31,535	12,533	20,147
Other, net	24,966	17,526	5,406
Total	$1,073,616	449,924	368,833

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2008 and 2007 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	2008	2007
Deferred tax assets		
Property and leasehold costs	$ 261,019	198,830
Liabilities for dismantlements	87,226	88,139
Postretirement and other employee benefits	114,221	87,906
Foreign tax credit carryforwards	41,043	41,043
Other deferred tax assets	119,314	107,219
Total gross deferred tax assets	622,823	523,137
Less valuation allowance	(266,755)	(214,120)
Net deferred tax assets	356,068	309,017
Deferred tax liabilities		
Property, plant and equipment	(430,056)	(307,008)
Accumulated depreciation, depletion and amortization	(604,267)	(587,331)
Deferred major repair costs	(18,142)	(9,451)
Foreign currency translation gains	(8,128)	(150,005)
Other deferred tax liabilities	(144,803)	(98,748)
Total gross deferred tax liabilities	(1,205,396)	(1,152,543)
Net deferred tax liabilities	$ (849,328)	(843,526)

In management's judgment, the net deferred tax assets in the preceding table will more likely than not be realized as reductions of future taxable income or by utilizing available tax planning strategies. The valuation allowance for deferred tax assets relates primarily to tax assets arising in foreign tax jurisdictions and foreign tax credit carryforwards. In the judgment of management at the present time, these tax assets are not likely to be realized. The foreign tax credit carryforwards expire in 2011, 2014 and 2015. The valuation allowance increased $52,635,000 in 2008, with these changes primarily offsetting the change in certain deferred tax assets. Any subsequent reductions of the valuation allowance will be reported as reductions of tax expense assuming no offsetting change in the deferred tax asset.

The Company has not recognized a deferred tax liability for undistributed earnings of its Canadian and certain other foreign subsidiaries because such earnings are considered indefinitely invested in foreign countries. As of December 31, 2008, undistributed earnings of the Company's subsidiaries considered indefinitely invested were approximately $3,177,000,000. The unrecognized deferred tax liability is dependent on many factors including withholding taxes under current tax treaties and foreign tax credits and is estimated to be $224,100,000. The Company does not consider undistributed earnings from certain other international operations to be indefinitely invested; however, any estimated tax liabilities upon repatriation of earnings from these international operations are expected to be offset with foreign tax credits.

Tax returns are subject to audit by various taxing authorities. Although the Company believes that recorded liabilities for unsettled issues are adequate, additional gains or losses could occur in future years from resolution of outstanding unsettled matters.

In October 2004 the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004 (the Act) became law. The FASB issued FASB Staff Position (FSP) 109-1 in December 2004 to provide guidance on the application of SFAS No. 109, Accounting for Income Taxes, to the provision within the Act that provides, beginning in 2005, a tax deduction on qualified production activities. The tax deduction phased in at 3% in 2005 and is scheduled to reach 9% in 2010, however, the deduction will be limited to 6% for oil rated qualified production activities. FSP 109-1 concluded that the tax benefit for the deduction should be recognized as realized. This FSP was effective upon issuance and the Company applied it in computing U.S. income tax expense beginning in 2005. The Company recorded tax benefits of nil, $4,725,000 and $2,450,000 in 2008, 2007 and 2006, respectively, related to the Act.

Uncertain Income Tax Positions

Effective January 1, 2007, the Company adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48). This interpretation clarifies the criteria for recognizing income tax benefits under FASB Statement No. 109, Accounting for Income Taxes, and requires additional disclosures about uncertain tax positions. Under FIN 48 the financial statement recognition of the benefit for a tax position is dependent upon the benefit being more likely than not to be sustainable upon audit by the applicable taxing authority. If this threshold is met, the tax benefit is then measured and recognized at the largest amount that is greater than 50 percent likely of being realized upon ultimate settlement. Upon adoption of FIN 48, the Company recognized a $709,000 increase in its liability for unrecognized income tax benefits, which is included in Deferred Credits and Other Liabilities in the Consolidated Balance Sheet, and it recognized a similar reduction of Retained Earnings. A reconciliation of the beginning and ending amount of the consolidated liability for unrecognized income tax benefits during the year ended December 31, 2008 follows.

(Thousands of dollars)	2008	2007
Balance at January 1	$25,598	16,436
Additions for tax positions related to respective year	6,558	9,101
Settlements with tax authorities	(3,837)	—
Settlements due to lapse of time	(7,502)	—
Changes due to translation of foreign currencies	(52)	61
Balance at December 31	$20,765	25,598

All additions or reductions to the above liability, other than translation of foreign currencies, affect the Company's effective income tax rate in the respective period of change. The Company accounts for any applicable interest and penalties on uncertain tax positions as a component of income tax expense. The Company also had other recorded liabilities as of December 31, 2008 and 2007 for interest and penalties of $2,640,000 and $4,065,000, respectively, associated with uncertain tax positions. Income tax expense for the years ended December 31, 2008 and 2007 included a benefit for interest and penalties of $1,185,000 and $2,228,000, respectively, associated with uncertain tax positions.

During the next twelve months, the Company currently expects to add to the liability for uncertain taxes for 2009 events in amounts that approximate the liabilities included for 2008. Although existing liabilities could be reduced by settlement with taxing authorities or lapse due to statute of limitations, the Company believes that the changes in its unrecognized tax benefits due to these events will not have a material impact on the Consolidated Statement of Income during 2008. The Company's tax returns in multiple jurisdictions are subject to audit by taxing authorities. These audits often take years to complete and settle. As of December 31, 2008, the earliest years remaining open for audit and/or settlement in our major taxing jurisdictions are as follows: United States – 2005; Canada – 2003; United Kingdom – 2005; Malaysia – 2006; and Ecuador – 2000.

Note J – Incentive Plans

Statement of Financial Accounting Standards (SFAS) No. 123 (revised 2004), Share-Based Payment (SFAS No. 123R), requires that the cost resulting from all share-based payment transactions be recognized as an expense in the financial statements using a fair value-based measurement method over the periods that the awards vest.

At the annual meeting of shareholders on May 9, 2007, two new incentive compensation plans were approved and the Employee Stock Purchase Plan was amended. The 2007 Annual Incentive Plan (2007 Annual Plan) authorizes the Executive Compensation Committee (the Committee) to establish specific performance goals associated with annual cash awards that may be earned by officers, executives and other key employees. Cash awards under the 2007 Annual Plan are determined based on the Company's actual financial and operating results as measured against the performance goals established by the Committee. The 2007 Long-Term Incentive Plan (2007 Long-Term Plan) authorizes the Committee to make grants of the Company's Common Stock to employees. These grants may be in the form of stock options (nonqualified or incentive), stock appreciation rights (SAR), restricted stock, restricted stock units, performance units, performance shares, dividend equivalents and other stock-based incentives. The 2007 Long-Term Plan expires in 2017. A total of 6,700,000 shares are issuable during the life of the 2007 Long-Term Plan, with annual grants limited to 1% of Common shares outstanding; allowed shares not granted may be granted in future years. The Company also has a Stock Plan for Non-Employee Directors that permits the issuance of restricted stock, restricted stock units and stock options or a combination thereof to the Company's Directors. Upon approval by shareholders, the 2007 Long-Term Plan replaced the 1992 Stock Incentive Plan (1992 Plan). The 1992 Plan authorized the Committee to make annual grants of the Company's Common Stock to executives and other key employees in the form of stock options (nonqualified or incentive), SAR, and/or restricted stock. Annual grants could not exceed 1% of shares outstanding at the end of the preceding year.

The Company generally expects to issue new shares to satisfy future stock option exercises and vesting of restricted stock and restricted stock units.

Amounts recognized in the financial statements with respect to share-based plans are as follows.

(Thousands of dollars)	2008	2007	2006
Compensation charged against income before income tax benefit	$ 25,656	22,241	18,814
Related income tax benefit recognized in income	8,628	7,778	6,112

As of December 31, 2008, there was $29,668,000 in compensation costs to be expensed over approximately the next two years related to unvested share-based compensation arrangements granted by the Company. Cash received from options exercised under all share-based payment arrangements for the years ended December 31, 2008, 2007 and 2006 was $29,687,000, $41,624,000 and $24,864,000, respectively. Total income tax benefits realized from tax deductions related to stock option exercises under share-based payment arrangements were $23,031,000, $32,844,000 and $14,134,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

STOCK OPTIONS – The Committee fixes the option price of each option granted at no less than fair market value (FMV) on the date of the grant and fixes the option term at no more than 10 years from such date. Each option granted to date under the 2007 Long-Term Plan and the 1992 Plan has had a term of 7 to 10 years, has been nonqualified, and has had an option price equal to or higher than FMV at date of grant. Under the 2007 Long-Term Plan and the 1992 Plan, one-half of each grant is exercisable after two years and the remainder after three years. Under the 2003 Director Plan, one-third of each grant is exercisable after each of the first three years.

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

	2008	2007	2006
Fair value per option grant	$ 17.69	15.02	$ 17.53
Assumptions			
Dividend yield	1.20%	1.20%	0.90%
Expected volatility	27.00%	29.00%	30.00%
Risk-free interest rate	2.58%	4.70%	4.42%
Expected life	4.75 yrs.	4.75 yrs.	4.75 yrs.

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

	Number of Shares	Average Exercise Price
Outstanding at December 31, 2005	8,414,637	$21.92
Granted at FMV	787,500	57.32
Exercised	(1,374,827)	17.18
Forfeited	(345,500)	45.73
Outstanding at December 31, 2006	7,481,810	25.41
Granted at FMV	895,500	51.07
Exercised	(2,249,300)	17.96
Forfeited	(326,500)	35.74
Outstanding at December 31, 2007	5,801,510	31.65
Granted at FMV	932,500	72.75
Exercised	(1,255,450)	20.56
Forfeited	(79,500)	60.40
Outstanding at December 31, 2008	5,399,060	$40.90
Exercisable at December 31, 2006	5,544,656	$18.31
Exercisable at December 31, 2007	3,997,010	22.44
Exercisable at December 31, 2008	3,375,810	28.46

Additional information about stock options outstanding at December 31, 2008 is shown below.

	Options Outstanding			Options Exercisable		
Range of Exercise Prices per Option	No. of Options	Avg. Life in Years	Aggregate Intrinsic Value	No. of Options	Avg. Life in Years	Aggregate Intrinsic Value
$ 8.92 to $19.43	1,150,800	2.2	$32,012,000	1,150,800	2.2	$32,012,000
$21.17 to $38.18	1,370,010	3.2	25,808,000	1,370,010	3.2	25,808,000
$45.23 to $72.75	2,878,250	4.8	—	855,000	3.4	—
	5,399,060	3.9	$57,820,000	3,375,810	2.9	$57,820,000

The total intrinsic value of options exercised during 2008, 2007 and 2006 was $71,405,000, $98,863,000 and $48,701,000, respectively. Intrinsic value is the excess of the market price of stock at date of exercise over the exercise price received by the Company upon exercise. Aggregate intrinsic value is nil when the exercise price of the stock option exceeds the market price of the Company's Common stock.

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

PERFORMANCE-BASED RESTRICTED STOCK AND RESTRICTED STOCK UNITS – Shares of restricted stock were granted under the 1992 Plan in certain years and restricted stock units were granted in 2008 and 2007 under the 2007 Long-Term Plan. Each grant will vest if the Company achieves specific objectives based on market conditions at the end of the designated performance period. Additional shares may be awarded if objectives are exceeded, but some or all shares may be forfeited if objectives are not met. The market conditions generally include a measure of the Company's total shareholder return over the performance period compared to an industry peer group of companies. During the performance period, a grantee receives dividends on restricted stock and may vote these shares, but shares are subject to transfer restrictions and are subject to forfeiture if a grantee terminates. No dividends are paid or voting rights exist on awards of restricted stock units. Changes in performance-based restricted stock and restricted stock units outstanding for each of the last three years are presented in the following table.

(Number of shares)	2008	2007	2006
Balance at beginning of year	798,497	680,292	478,445
Granted	328,000	299,000	265,750
Forfeited	(319,675)	(180,795)	(63,903)
Balance at end of year	806,822	798,497	680,292

The fair value of the performance-based awards granted in 2008, 2007 and 2006 was estimated on the date of grant using a Monte Carlo valuation model. If performance goals are not met, shares will not be awarded, but recognized compensation cost associated with the stock award would not be reversed.

Expected volatility was based on daily historical volatility of the Company's stock price compared to a peer group average over a three year period. The risk-free interest rate is based on the yield curve of three year U.S. Treasury bonds and the stock beta was calculated using three years of historical averages of daily stock data for Murphy and the peer group. The assumptions used in the valuation of the performance awards granted in 2008, 2007 and 2006 are presented in the following table.

	2008	2007	2006
Fair value per share at grant date	$52.70 – $62.53	$45.05 – $48.23	$ 37.33
Assumptions			
Expected volatility	29.00%	27.10%	26.30%
Risk-free interest rate	2.08%	4.64%	4.49%
Stock beta	0.885	0.912	0.955
Expected life	3.00 yrs.	3.00 yrs.	3.00 yrs.

TIME-LAPSE RESTRICTED STOCK – Shares of restricted stock were granted to the Company's Directors under the 2003 Director Plan and vest on the third anniversary of the date of grant. In addition, the Committee awarded 60,000 time-lapse restricted stock units to an officer during 2008. The fair value of these awards was estimated based on the fair market value of the Company's stock on the date of grant, which was $72.75 per share in 2008, $51.07 per share in 2007, and $57.32 per share in 2006. Changes in time-lapse restricted stock and restricted stock units outstanding for each of the periods are presented in the following table.

(Number of shares)	2008	2007	2006
Balance at beginning of year	68,289	56,142	35,574
Granted	84,930	32,750	20,568
Expired	(20,400)	(15,706)	—
Forfeited	—	(4,897)	—
Balance at end of year	132,819	68,289	56,142

EMPLOYEE STOCK PURCHASE PLAN (ESPP) – The Company has an ESPP under which the Company's Common Stock can be purchased by eligible U.S. and Canadian employees. Each quarter, an eligible employee may elect to withhold up to 10% of his or her salary to purchase shares of the Company's stock at the end of the quarter at a price equal to 90% of the fair value of the stock as of the first day of the quarter. The ESPP was amended in 2007 to increase the authorized number of shares and increase its term. The ESPP will now terminate on the earlier of the date that employees have purchased all 980,000 authorized shares or June 30, 2017. Employee stock purchases under the ESPP were 20,715 shares at an average price of $73.94 per share in 2008, 30,011 shares at $52.68 per share in 2007, and 28,280 shares at $45.88 per share in 2006. At December 31, 2008, 450,479 shares remained available for sale under the ESPP. Compensation costs related to the ESPP are estimated based on the value of the 10% discount and the fair value of the option that provides for the refund of participant withholdings, and such expenses were $401,000 in 2008, $253,000 in 2007 and $256,000 in 2006. The fair value per share issued under the ESPP was approximately $13.03, $8.32, and $7.57 for the years ended December 31, 2008, 2007 and 2006, respectively.

SAVINGS-RELATED SHARE OPTION PLAN (SOP) – One of the Company's U.K. subsidiaries provides a plan that allows shares of the Company's Common stock to be purchased by eligible employees using payroll withholdings. An eligible employee may elect to withhold from £5 to £250 per month to purchase shares of Company stock at a price equal to 90% of the fair value of the stock as of the date of grant. The SOP plan has a term of three years and employee withholdings are fixed over the life of the plan. At the end of the term of the SOP plan an employee receives interest on withholdings and has six months to either use all or part of the withholdings plus credited interest to purchase shares of Company stock or receive a repayment of withholdings plus credited interest. Compensation costs related to the SOP plan are estimated based on the value of the 10% discount and the fair value of the option that allows the employee to receive a repayment of withholdings plus credited interest. The fair value per share of the SOP plans with holding periods ending in May 2007, December 2009 and August 2010 were determined to be $11.64, $19.57 and $19.90, respectively.

CASH AWARDS – The Committee also administers the Company's incentive compensation plans, which provide for annual or periodic cash awards to officers, directors and key employees. These cash awards are generally determinable based on the Company achieving specific financial and/or operational objectives. Compensation expense of $23,793,000, $23,716,000 and $14,862,000 was recorded in 2008, 2007 and 2006, respectively, for these plans.

Note K – Employee and Retiree Benefit Plans

PENSION AND OTHER POSTRETIREMENT PLANS – The Company has defined benefit pension plans that are principally noncontributory and cover most full-time employees. All pension plans are funded except for the U.S. and Canadian nonqualified supplemental plans and the U.S. directors' plan. All U.S. tax qualified plans meet the funding requirements of federal laws and regulations. Contributions to foreign plans are based on local laws and tax regulations. The Company also sponsors health care and life insurance benefit plans, which are not funded, that cover most retired U.S. employees. The health care benefits are contributory; the life insurance benefits are noncontributory.

In September 2006, the FASB issued SFAS No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of SFAS Nos. 87, 88, 106 and 132R (SFAS No. 158). This statement requires the Company to recognize in its consolidated balance sheet the overfunded or underfunded status of its defined benefit plans as an asset or liability and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This statement also requires that the Company measure the funded status of all plans as of December 31 rather than September 30 as previously permitted.

The Company adopted the requirement to use a December 31 measurement date for defined benefit plan measurement beginning in 2007. The transition from a measurement date as of September 30 to December 31 required the Company to reduce its consolidated Retained Earnings as of January 1, 2007 by $4,301,000 to recognize the one-time after-tax effect of an additional three months of net periodic benefit expense for its retirement and postretirement benefit plans.

The tables that follow provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets for the years ended December 31, 2008 and 2007 and a statement of the funded status as of December 31, 2008 and 2007.

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2008	2007	2008	2007
Change in benefit obligation				
Obligation at January 1	$ 446,386	429,398	80,685	72,567
Adjustment due to adoption of SFAS No. 158	—	2,606	—	1,685
Service cost	17,928	11,424	2,708	2,283
Interest cost	27,667	24,492	5,087	4,354
Plan amendments	2,582	—	—	—
Participant contributions	36	51	846	941
Actuarial (gain) loss	(1,035)	(5,456)	2,802	3,257
Medicare Part D subsidy	—	—	195	387
Exchange rate changes	(29,756)	5,313	—	—
Benefits paid	(22,111)	(21,442)	(5,005)	(4,789)
Other	—	—	—	—
Obligation at December 31	441,697	446,386	87,318	80,685
Change in plan assets				
Fair value of plan assets at January 1	339,259	313,214	—	—
Adjustment due to adoption of SFAS No. 158	—	3,736	—	—
Actual return on plan assets	(63,312)	25,107	—	—
Employer contributions	50,639	12,156	3,964	3,461
Participant contributions	36	51	846	941
Medicare Part D subsidy	—	—	195	387
Exchange rate changes	(26,090)	6,785	—	—
Benefits paid	(22,111)	(21,442)	(5,005)	(4,789)
Other	(338)	(348)	—	—
Fair value of plan assets at December 31	278,083	339,259	—	—
Funded status and amounts recognized in the Consolidated Balance Sheets at December 31				
Deferred charges and other assets	11,069	17,649	—	—
Other accrued liabilities	(13,244)	(33,251)	—	—
Deferred credits and other liabilities	(161,439)	(91,525)	(87,318)	(80,685)
Funded status and net plan liability recognized at December 31	$(163,614)	(107,127)	(87,318)	(80,685)

At December 31, 2008, amounts included in accumulated other comprehensive income (AOCI), before reduction for associated deferred income taxes, which have not been recognized in net periodic benefit expense are shown in the following table.

(Thousands of dollars)	Pension Benefits 2008	Other Postretirement Benefits 2008
Net loss	$(169,101)	(32,528)
Prior service (cost) credit	(9,686)	2,511
Transitional asset	2,996	—
	$(175,791)	(30,017)

Amounts included in AOCI at December 31, 2008 that are expected to be amortized into net periodic benefit expense during 2009 are shown in the following table.

(Thousands of dollars)	Pension Benefits 2008	Other Postretirement Benefits 2008
Net loss	$ (11,239)	(1,673)
Prior service (cost) credit	(1,793)	264
Transitional asset	(499)	—
	$ (13,531)	(1,409)

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

(Thousands of dollars)	Projected Benefit Obligations 2008	Projected Benefit Obligations 2007	Accumulated Benefit Obligations 2008	Accumulated Benefit Obligations 2007	Fair Value of Plan Assets 2008	Fair Value of Plan Assets 2007
Funded qualified plans where accumulated benefit obligation exceeds fair value of plan assets	$ 370,793	377,503	317,418	330,511	254,819	302,970
Unfunded nonqualified and directors' plans where accumulated benefit obligation exceeds fair value of plan assets	58,709	50,244	40,667	39,970	—	—
Unfunded other postretirement plans	87,318	80,685	87,318	80,685	—	—

The table that follows provides the components of net periodic benefit expense for each of the three years ended December 31, 2008.

(Thousands of dollars)	Pension Benefits 2008	Pension Benefits 2007	Pension Benefits 2006	Other Postretirement Benefits 2008	Other Postretirement Benefits 2007	Other Postretirement Benefits 2006
Service cost	$ 17,928	11,424	10,264	2,708	2,283	2,128
Interest cost	27,667	24,492	21,670	5,087	4,354	3,923
Expected return on plan assets	(23,131)	(21,644)	(20,315)	—	—	—
Amortization of prior service cost	1,693	1,422	1,929	(264)	(264)	(277)
Amortization of transitional asset	(499)	(494)	(490)	—	—	—
Recognized actuarial loss	5,119	5,746	6,416	1,639	1,589	1,637
	28,777	20,946	19,474	9,170	7,962	7,411
Special termination benefits expense	—	—	4,748	—	—	—
Curtailment expense (benefit)	—	—	594	—	—	(152)
Net periodic benefit expense	$ 28,777	20,946	24,816	9,170	7,962	7,259

Termination and curtailment expense in 2006 primarily related to the reorganization of the Company's U.S. exploration and production operation.

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

(Thousands of dollars)	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
Benefit obligation at December 31	$84,696	117,224	—	—
Fair value of plan assets at December 31	78,025	106,057	—	—
Net plan liability (asset) recognized	(6,671)	11,165	—	—
Net periodic benefit expense	8,231	3,342	—	—

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2008 and 2007 and net periodic benefit expense for the years 2008 and 2007.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits December 31		Postretirement Benefits December 31		Pension Benefits Year		Postretirement Benefits Year	
	2008	2007	2008	2007	2008	2007	2008	2007
Discount rate	6.40%	6.25%	6.50%	6.50%	6.31%	5.76%	6.50%	6.00%
Expected return on plan assets	6.58%	6.93%	—	—	6.58%	6.89%	—	—
Rate of compensation increase	4.41%	4.42%	—	—	4.41%	4.40%	—	—

The discount rates used for purposes of determining the plan obligations and expense are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate which is the basis for selecting the discount rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Expected compensation increases are based on anticipated future averages for the Company.

The weighted average asset allocation for the Company's benefit plans at the annual measurement dates of December 31, 2008 and 2007 are presented in the following table.

	December 31,	
	2008	2007
Equity securities	52.2%	57.3%
Debt securities	47.1	41.4
Cash	0.7	1.3
	100.0%	100.0%

The Company has directed the asset investment advisors of its benefit plans to maintain a portfolio nearly balanced between equity and debt securities. The investment advisors may vary the asset mix within the range of 40% to 70% for equity securities and 30% to 60% for debt securities. The Company believes that over time a balanced to slightly heavier weighting of the portfolio in equity securities compared to debt securities represents the most appropriate long-term mix for future investment return on domestic plans' assets. Investment advisors are not permitted to invest benefit plan assets in Murphy Oil's Common Stock.

The Company's weighted average expected return on plan assets was 6.58% in 2008 and the return was determined based on an assessment of actual long-term historical returns and expected future returns for a portfolio with investment characteristics similar to that maintained by the plans. The 6.58% expected return was based on an expected average future equity securities return of 8.47% and a debt securities return of 5.24% and is net of average expected investment expenses of 0.52%. Over the last 10 years, the return on funded retirement plan assets has averaged 5.43%.

During 2008, the Company made contributions of $30,010,000 to its domestic defined benefit pension plans, $20,629,000 to its foreign defined benefit pension plan and $3,964,000 to its domestic postretirement benefits plan. The Company currently expects during 2009 to make contributions of $43,153,000 to its domestic defined benefit pension plans, $7,077,000 to its foreign defined benefit pension plans and $4,890,000 to its domestic postretirement benefits plan. The 2009 retirement plan contribution includes a currently anticipated voluntary contribution of $30,000,000.

Benefit payments reflecting expected future service as appropriate, which are expected to be paid in future years from the assets of the plans or by the Company are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
2009	$ 22,681	5,413
2010	23,423	5,891
2011	24,061	6,267
2012	24,906	6,653
2013	26,156	7,037
2014-2018	149,858	40,484

For purposes of measuring postretirement benefit obligations at December 31, 2008, the future annual rates of increase in the cost of health care were assumed to be 9.0% for 2009 decreasing each year to an ultimate rate of 5.0% in 2018 and thereafter.

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

(Thousands of dollars)	1% Increase	1% Decrease
Effect on total service and interest cost components of net periodic postretirement benefit expense for the year ended December 31, 2008	$ 1,314	(1,046)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 2008	11,887	(9,768)

During 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) became law. Among other provisions, the Act changed prescription drug coverage under Medicare beginning in 2006. Generally, companies that provide qualifying prescription drug coverage that is deemed actuarially equivalent to Medicare coverage for retirees aged 65 and above will be eligible to receive a federal subsidy equal to 28% of drug costs between $250 and $5,000 per annum of each covered individual that does not elect to receive coverage under the new Medicare Part D. The Company currently provides prescription drug coverage to qualifying retirees under its retiree medical plan. As a result of provisions in the Act, the Company’s postretirement benefit expense was reduced by $2,457,000, $1,507,000 and $1,422,000 during 2008, 2007 and 2006, respectively.

THRIFT PLANS – Most full-time employees of the Company may participate in thrift or savings plans by allotting up to a specified percentage of their base pay. The Company matches contributions at a stated percentage of each employee’s allotment based on years of participation in the plans. A U.K. savings plan allows eligible employees to allot a portion of their base pay to purchase Company Common Stock at market value. Such employee allotments are matched by the Company. Common Stock issued from the Company’s treasury under this U.K. savings plan was 7,780 shares in 2007 and 16,571 shares in 2005. Amounts charged to expense of these U.S. and U.K. plans were $6,215,000 in 2008, $9,252,000 in 2007 and $2,957,000 in 2006.

Note L – Financial Instruments and Risk Management

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

- *Crude Oil Purchase Price Risks* – The Company purchases crude oil as feedstock at its U.S. and U.K. refineries and is therefore subject to commodity price risk. Short-term derivative instruments were outstanding at December 31, 2008 to manage the 2009 purchase price of 1,063,000 barrels of crude oil at the Company's Superior, Wisconsin refinery. At December 31, 2007 essentially offsetting short-term derivative instruments were outstanding to manage the 2008 purchase price of 403,000 barrels of crude oil at the Company's Meraux, Louisiana refinery. The total impact of marking these contracts to market at the respective year-end was pretax charges of $1,378,000 in 2008 and $40,000 in 2007.
- *Natural Gas Fuel Price Risks* – The Company purchases natural gas as fuel at its Meraux, Louisiana and Superior, Wisconsin refineries, and as such, is subject to commodity price risk related to the purchase price of this gas. Murphy hedged the cash flow risk associated with the cost of a portion of the natural gas it purchased during 2006 by entering into financial contracts known as natural gas swaps with a notional volume during 2006 of 720,000 MMBTU (1 MMBTU = 1 million British Thermal Units). Under the natural gas swaps, the Company paid a fixed rate averaging $3.35 per MMBTU and received a floating rate in each month of settlement based on the average NYMEX price for the final three trading days of the month. Murphy has a risk management control system to monitor natural gas price risk attributable both to forecasted natural gas requirements and to Murphy's natural gas swaps. The control system involves using analytical techniques, including various correlations of natural gas purchase prices to future prices, to estimate the impact of changes in natural gas fuel prices on Murphy's cash flows. The fair value of the effective portions of the natural gas swaps and changes thereto was deferred in AOCI and was subsequently reclassified into Operating Expenses in the income statements in the periods in which the hedged natural gas fuel purchases occurred. For the year ended December 31, 2006, expense from cash flow hedging ineffectiveness for these contracts was $28,000. During the year ended December 31, 2006, the Company received approximately $2,791,000 in cash proceeds from maturing swap agreements.
- *Crude Oil Sales Price Risks* – The sales price of crude oil produced by the Company is subject to commodity price risk. Murphy hedged the cash flow risk associated with the sales price for a portion of its 2006 Canadian heavy oil production by entering into forward sale contracts covering a notional volume of approximately 4,000 barrels per day. The Company paid the average of the posted price at the Hardisty terminal in Canada for each month and received a fixed price of $25.23 per barrel. Murphy has a risk management control system to monitor crude oil price risk attributable both to forecasted crude oil sales prices and to Murphy's hedging instruments. The control system involves using analytical techniques, including various correlations of crude oil sales prices to futures prices, to estimate the impact of changes in crude oil prices on Murphy's cash flows from the sale of crude oil. The fair value of the effective portions of the crude oil sales price hedges and changes thereto was deferred in AOCI and was subsequently reclassified into Sales and Other Operating Revenues in the income statement in the periods in which the hedged crude oil sales occurred. During 2006, earnings were increased by $160,000 for cash flow hedging ineffectiveness on crude oil sales price hedges, and the Company paid approximately $29,373,000 for settlement of maturing crude oil sales swaps.

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

Note M – Earnings per Share

The following table reconciles the weighted-average shares outstanding for computation of basic and diluted income per Common share for each of the three years ended December 31, 2008. No difference existed between net income used in computing basic and diluted income per Common share for these years.

(Weighted-average shares outstanding)	2008	2007	2006
Basic method	189,608,846	188,027,557	186,105,086
Dilutive stock options	2,524,826	3,113,180	3,053,325
Diluted method	192,133,672	191,140,737	189,158,411

Certain outstanding options to purchase shares of Common stock at year-end 2008 and 2006 were not included in the computation of diluted earnings per share because the incremental shares from assumed conversion were antidilutive. These included options for 924,000 shares at a weighted average of $72.75 at year-end 2008, and 706,000 shares at a weighted average price of $57.32 at year-end 2006. There were no antidilutive options for the 2007 period.

Note N – Other Financial Information

INVENTORIES – Inventories accounted for under the LIFO method totaled $342,984,000 and $361,651,000 at December 31, 2008 and 2007, respectively, and these amounts were $202,477,000 and $709,743,000 less than such inventories would have been valued using the FIFO method.

ACCUMULATED OTHER COMPREHENSIVE INCOME – At December 31, 2008 and 2007, the components of Accumulated Other Comprehensive Income were as follows.

(Thousands of dollars)	2008	2007
Foreign currency translation gains, net of tax	$ 45,517	428,538
Retirement and postretirement plan liability adjustments, net of tax	(133,214)	(76,773)
Balance at end of year	$ (87,697)	351,765

At December 31, 2008, components of the net foreign currency translation gain of $45,517,000 were gains of $10,373,000 for Canadian dollars, $32,139,000 for pounds sterling and $3,005,000 for other currencies. Foreign currency translation gains shown in the table are net of income taxes of $8,128,000 and $150,005,000 at year-end 2008 and 2007, respectively. Net losses from foreign currency transactions included in the Consolidated Statements of Income were $105,620,000 in 2008, $20,637,000 in 2007 and $8,000,000 in 2006.

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

CASH FLOW DISCLOSURES – Cash income taxes paid were $380,602,000, $297,274,000 and $466,087,000 in 2008, 2007 and 2006, respectively. Interest paid, net of amounts capitalized, was $43,715,000, $22,274,000 and $7,270,000 in 2008, 2007 and 2006, respectively.

Noncash operating working capital (increased) decreased during each of the three years ended December 31, 2008 as follows.

(Thousands of dollars)	2008	2007	2006
Accounts receivable	$ 386,605	(445,677)	(128,004)
Inventories	22,474	(107,945)	(96,122)
Prepaid expenses	(12,959)	57,089	(103,435)
Deferred income tax assets	56,451	(65,391)	19,403
Accounts payable and accrued liabilities	(701,450)	661,599	96,569
Current income tax liabilities	342,589	45,779	(42,881)
Net (increase) decrease in noncash operating working capital, excluding acquisition of the Milford Haven refinery in 2007	$ 93,710	145,454	(254,470)

Note O – Assets and Liabilities Measured at Fair Value

As described in Note B, the Company adopted SFAS No. 157, Fair Value Measurements (SFAS No. 157), on January 1, 2008, other than for nonrecurring nonfinancial assets and liabilities, which will be effective for the Company on January 1, 2009. SFAS No. 157 establishes a fair value hierarchy based on the quality of inputs used to measure fair value, with Level 1 being the highest quality and Level 3 being the lowest quality. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs which reflect assumptions about pricing by market participants.

The fair value measurements for the Company's financial liabilities accounted for at fair value on a recurring basis at December 31, 2008 are presented in the following table.

		Fair Value Measurements at Reporting Date Using		
(Thousands of dollars)	December 31, 2008	Quoted Prices in Active Markets for Identical Assets (Liabilities) (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Liabilities				
Nonqualified employee savings plan	$ (6,804)	(6,804)	—	—
Commodity derivatives	(1,378)	—	(1,378)	—
Total liabilities at fair value	$ (8,182)	(6,804)	(1,378)	—

The nonqualified employee savings plan is an unfunded savings plan through which the owners seek a return via phantom investments in equity securities and/or mutual funds. Fair value of this liability was based on quoted prices for these equity securities and mutual funds. The fair value of commodity derivatives was determined based on market quotes for WTI crude contracts at the balance sheet date. The income effect of the changes in the fair value of nonqualified employee savings plan is recorded in Selling and General Expense in the Consolidated Statement of Income, while the change in fair value of commodity derivatives is recorded in Crude Oil and Product Purchases. The carrying value of the Company's Cash and Cash Equivalents, Accounts Receivable and Accounts Payable approximates fair value.

The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2008 and 2007. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties. The table excludes cash and cash equivalents, trade accounts receivable, short-term notes payable, trade accounts payable and accrued expenses, all of which had fair values approximating carrying amounts. The carrying value of Canadian government securities is determined based on cost plus earned interest. The fair value of current and long-term debt was estimated based on rates offered to the Company at that time for debt of the same maturities. The Company has off-balance sheet exposures relating to certain financial guarantees and letters of credit. The fair value of these, which represents fees associated with obtaining the instruments, was nominal.

	At December 31,			
	2008		2007	
(Thousands of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets (liabilities):				
Canadian government securities with maturities greater than 90 days at the date of acquisition	$ 420,340	422,138	—	—
Current and long-term debt	(1,028,794)	(910,862)	(1,521,364)	(1,517,678)

Note P – Hurricane and Insurance Related Matters

In 2007 and 2006, the Company recorded pretax expenses, net of anticipated insurance recoveries, of $3,000,000 and $109,244,000, respectively, associated with hurricanes that occurred in the United States in 2005. The costs for the respective periods are reported in Net Costs Associated With Hurricanes in the Consolidated Statements of Income. The 2007 costs relate to a reduction in the estimated insurance recoverable on Meraux property damages based on the most recent estimate of loss limits as provided by the Company's primary property insurer. The components of the 2006 costs included $107,410,000 at the Meraux refinery, including $49,500,000 for refinery repair costs not expected to be recovered due to certain coverage limits for the Company's insurance policies; $5,909,000 for incremental insurance costs; $9,013,000 for other uninsured incremental expenses incurred; $18,000,000 for settlement of oil spill class action litigation; and $24,988,000 for depreciation and salaries while the refinery was temporarily idled prior to restarting in mid-2006. Total amounts receivable from insurers for hurricane-related matters were $74,562,000 at December 31, 2008, of which $48,030,000 was classified as current in the Consolidated Balance Sheet. Through 2008, the Company's refining and marketing operations received Hurricane Katrina insurance proceeds of $118,040,000 related to property damage incurred as a result of Hurricane Katrina. See Note R for additional information regarding environmental and other contingencies relating to Hurricane Katrina.

The Company maintains insurance coverage related to losses of production and profits for occurrences such as storms, fires and other issues. During 2007, the Company's exploration and production operations recorded $2,048,000 in business interruption insurance recoveries relating to Hurricane Rita in 2005. In 2006, the Company recorded $15,700,000 in business interruption insurance recoveries relating to Hurricane Katrina in 2005, and $5,000,000 due to lost production at Terra Nova related to the mechanical failure of the main power generator. These business interruption collections were reported in Sales and Other Operating Revenues in the Consolidated Statements of Income.

Note Q – Commitments

The Company leases land, gasoline stations, and production and other facilities under operating leases. The most significant operating lease is associated with the Kikeh field floating, production, storage and offloading facility in Malaysia, which was initiated in 2007 for an eight-year term prior to start-up of this significant oil field. During the next five years, expected future rental payments under all operating leases are approximately $96,276,000 in 2009, $94,435,000 in 2010, $86,570,000 in 2011, $82,841,000 in 2012 and $82,260,000 in 2013. Rental expense for noncancellable operating leases, including contingent payments when applicable, was $88,890,000 in 2008, $61,439,000 in 2007 and $46,336,000 in 2006.

To assure long-term supply of hydrogen at its Meraux, Louisiana refinery, the Company has contracted to purchase up to 35 million standard cubic feet of hydrogen per day at market prices through 2021. The contract requires the payment of a base facility charge for use of the facility. Future required minimum annual payments for base facility charges for the next five years are $6,625,000 in 2009, $6,890,000 in 2010, $7,166,000 in 2011, $7,452,000 in 2012 and $7,750,000 in 2013. Base facility charges and hydrogen costs incurred in 2008, 2007 and 2006 totaled $45,396,000, $42,512,000 and $23,903,000, respectively. There were no base facility charges or hydrogen costs incurred at the Meraux refinery for the first four months of 2006 while the facility was shut-down for repairs after Hurricane Katrina.

The Company has operating, production handling and transportation agreements providing for processing, production handling and transportation services for hydrocarbon production from certain fields in the Gulf of Mexico and Western Canada. These agreements require minimum monthly or annual payments for processing or transportation charges through 2013. Future required minimum monthly payments for the next five years are $4,654,000 in 2009, $9,036,000 in 2010, $10,512,000 in 2011, $7,770,000 in 2012 and $2,249,000 in 2013. Under certain circumstances, the Company is required to pay additional amounts depending on the actual hydrocarbon quantities processed under the agreement. Costs incurred under these arrangements were $9,276,000 in 2008, $13,476,000 in 2007 and $27,007,000 in 2006.

Additionally, the Company has a Reserved Capacity Service Agreement providing for the availability of needed crude oil storage capacity for certain oil fields through 2020. Under the agreement, the Company must make specified minimum payments monthly. Future required minimum annual payments are approximately $3,500,000 in 2009 through 2013. In addition, the Company is required to pay additional amounts depending on actual crude oil quantities under the agreement. Total payments under the agreement were $3,703,000 in 2008, $3,992,000 in 2007 and $3,666,000 in 2006.

In 2006, the Company committed to fund an educational assistance program known as the "El Dorado Promise." Under this commitment, the Company will pay $5,000,000 per year from 2007 to 2016 to cover a specified amount of college expenses for eligible graduates of El Dorado High School in Arkansas. The first three payments have been made through January 2009. Based on SFAS 116, Accounting for Contributions Received and Contributions Made, the Company recorded a discounted liability of $38,700,000 in 2006 for this unconditional commitment. The liability was discounted at the Company's 10-year borrowing rate and the discounted liability will increase for accretion monthly with a corresponding charge to Selling and General Expense in the Consolidated Statement of Income. Total accretion cost included in Selling and General Expense in 2008 and 2007 was $1,931,000 and $2,112,000, respectively.

Commitments for capital expenditures were approximately $2,129,136,000 at December 31, 2008, including $172,900,000 for costs to develop deepwater Gulf of Mexico fields, $1,015,755,000 for field development and future work commitments in Malaysia, and $322,528,000 for field development and a work commitment in the Republic of the Congo.

The Company has entered into contracts to hire various drilling rigs and associated equipment for periods beyond December 31, 2008. These rigs are primarily utilized for deepwater drilling operations in the Gulf of Mexico, Malaysia, Canada, Australia and the Republic of the Congo. Future commitments under these contracts, all of which expire by 2012, total approximately $865,000,000. A significant portion of these costs are expected to be borne by other working interest owners as partners of the Company when the wells are drilled. These drilling costs are generally expected to be accounted for as capital expenditures as incurred during the contract periods.

Note R – Contingencies

The Company's operations and earnings have been and may be affected by various forms of governmental action both in the United States and throughout the world. Examples of such governmental action include, but are by no means limited to: tax increases and retroactive tax claims; royalty and revenue sharing increases; import and export controls; price controls; currency controls; allocation of supplies of crude oil and petroleum products and other goods; expropriation of property; restrictions and preferences affecting the issuance of oil and gas or mineral leases; restrictions on drilling and/or production; laws and regulations intended for the promotion of safety and the protection and/or remediation of the environment; governmental support for other forms of energy; and laws and regulations affecting the Company's relationships with employees, suppliers, customers, stockholders and others. Because governmental actions are often motivated by political considerations, may be taken without full consideration of their consequences, and may be taken in response to actions of other governments, it is not practical to attempt to predict the likelihood of such actions, the form the actions may take or the effect such actions may have on the Company.

ENVIRONMENTAL MATTERS – Murphy and other companies in the oil and gas industry are subject to numerous federal, state, local and foreign laws and regulations dealing with the environment. Violation of federal or state environmental laws, regulations and permits can result in the imposition of significant civil and criminal penalties, injunctions and construction bans or delays. A discharge of hazardous substances into the environment could, to the extent such event is not insured, subject the Company to substantial expense, including both the cost to comply with applicable regulations and claims by neighboring landowners and other third parties for any personal injury and property damage that might result.

The Company currently owns or leases, and has in the past owned or leased, properties at which hazardous substances have been or are being handled. Although the Company has used operating and disposal practices that were standard in the industry at the time, hazardous substances may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes were not under Murphy's control. Under existing laws the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. While some of these historical properties are in various stages of negotiation, investigation, and/or cleanup, the Company is investigating the extent of any such liability and the availability of applicable defenses and believes costs related to these sites will not have a material adverse affect on Murphy's net income, financial condition or liquidity in a future period.

The Company's liability for remedial obligations includes certain amounts that are based on anticipated regulatory approval for proposed remediation of former refinery waste sites. Although regulatory authorities may require more costly alternatives than the proposed processes, the cost of such potential alternative processes is not expected to exceed the accrued liability by a material amount. Certain environmental expenditures are likely to be recovered by the Company from other sources, primarily environmental funds maintained by certain states. Since no assurance can be given that future recoveries from other sources will occur, the Company has not recorded a benefit for likely recoveries at December 31, 2008.

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

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

LEGAL MATTERS – On September 9, 2005, a class action lawsuit was filed in federal court in the Eastern District of Louisiana seeking unspecified damages to the class comprised of residents of St. Bernard Parish caused by a release of crude oil at Murphy Oil USA, Inc.'s (a wholly-owned subsidiary of Murphy Oil Corporation) Meraux, Louisiana, refinery as a result of flood damage to a crude oil storage tank following Hurricane Katrina. Additional class action lawsuits were consolidated with the first suit into a single action in the U.S. District Court for the Eastern District of Louisiana. In September 2006, the Company reached a settlement with class counsel and on October 10, 2006, the court granted preliminary approval of a class action Settlement Agreement. A Fairness Hearing was held January 4, 2007 and the court entered its ruling on January 30, 2007 approving the class settlement. The majority of the settlement of $330 million will be paid by insurance. The Company recorded an expense of $18 million in 2006 related to settlement costs not expected to be covered by insurance. As part of the settlement, all properties in the class area received a fair and equitable cash payment and have had residual oil cleaned. As part of the settlement, the Company offered to purchase all properties in an agreed area adjacent to the west side of the Meraux refinery; these property purchases and associated remediation have been paid by the Company at a cost of $55 million. As of December 31, 2008, the Company has fulfilled its obligations under the Class Action Settlement Agreement. Approximately 40 non-class action suits regarding the oil spill have been filed and remain pending. The Company believes that insurance coverage exists and it does not expect to incur significant costs associated with this litigation. On August 14, 2007, four of the Company's high level excess insurers noticed the Company for arbitration in London. The insurers do not deny coverage, but seek arbitration as to whether and to what extent expenditures made by the Company in resolving the oil spill litigation have reached the attachment point for covered loss under their respective policies. The Company is of the position that full coverage should be afforded. Accordingly, the Company believes neither the ultimate resolution of the remaining litigation nor the insurance arbitration will have a material adverse effect on its net income, financial condition or liquidity in a future period.

On June 10, 2003, a fire severely damaged the Residual Oil Supercritical Extraction (ROSE) unit at the Company's Meraux, Louisiana refinery. The ROSE unit recovers feedstock from the heavy fuel oil stream for conversion into gasoline and diesel. Subsequent to the fire, numerous class action lawsuits have been filed seeking damages for area residents. All the lawsuits have been administratively consolidated into a single legal action in St. Bernard Parish, Louisiana, except for one such action which was filed in federal court. Additionally, individual residents of Orleans Parish, Louisiana, have filed an action in that venue. On May 5, 2004, plaintiffs in the consolidated action in St. Bernard Parish amended their petition to include a direct action against certain of the Company's liability insurers. The St. Bernard Parish action has since been removed to federal court, which issued an order on July 25, 2008 denying plaintiff's request to certify the case as a class action. In responding to this direct action, one of the Company's insurers, AEGIS, has raised lack of coverage as a defense. The Company believes that this contention lacks merit and has been advised by counsel that the applicable policy does provide coverage for the underlying incident. Because the Company believes that insurance coverage exists for this matter, it does not expect to incur any significant costs associated with the lawsuits. Accordingly, the Company continues to believe that the ultimate resolution of the June 2003 ROSE fire litigation will not have a material adverse effect on its net income, financial condition or liquidity in a future period.

Murphy and its subsidiaries are engaged in a number of other legal proceedings, all of which Murphy considers routine and incidental to its business. Based on information currently available to the Company, the ultimate resolution of environmental and legal matters referred to in this note is not expected to have a material adverse effect on the Company's net income, financial condition or liquidity in a future period.

OTHER MATTERS – In the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide financial guarantees or letters of credit that may be drawn upon if the Company fails to perform under those contracts. At December 31, 2008, the Company had contingent liabilities of $7,798,000 under a financial guarantee described in the following paragraph and $120,029,000 on outstanding letters of credit. The Company has not accrued a liability in its balance sheet related to these letters of credit because it is believed that the likelihood of having these drawn is remote.

The Company owns a 3.2% interest in the Louisiana Offshore Oil Port (LOOP) that it accounts for at cost. At year-end 2008, LOOP had $243,690,000 of outstanding bonds, which mature in varying amounts between 2014 and 2027 and which are secured by a Throughput and Deficiency Agreement (T&D). The Company is obligated to ship crude oil in quantities sufficient for LOOP to pay certain of its expenses and obligations, including long-term debt secured by the T&D, or to make cash payments for which the Company will receive credit for future throughput. No other collateral secures the investee's obligation or the Company's guarantee. As of December 31, 2008, it is not probable that the Company will be required to make payments under the guarantee; therefore, no liability has been recorded for the Company's obligation under the T&D agreement. The Company continues to monitor conditions that are subject to guarantees to identify whether it is probable that a loss has occurred, and it would recognize any such losses under the guarantees should losses become probable.

The joint agreement between the owners of Terra Nova requires a redetermination of working interests based on an analysis of reservoir quality among fault separated areas where varying ownership interests exist. The operator expects to complete the initial redetermination in March 2009, and the calculation is expected to be the subject of renegotiation and/or arbitration before final interests are determined. This redetermination is expected to be finalized in 2010, and is retroactive to 2005. Upon completion of the redetermination process, a cash settlement is required among partners to balance cash flows retroactive to the effective date. The Company cannot predict the final outcome of the redetermination process.

Note S – Common Stock Issued and Outstanding

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2008 is shown below.

(Number of shares outstanding)	2008	2007	2006
At beginning of year	189,714,149	187,572,200	185,946,678
Stock options exercised	1,275,971	2,249,300	1,374,827
Employee stock purchase and thrift plans	19,755	37,679	28,280
Restricted stock awards, net of forfeitures	(299,334)	(144,442)	222,415
All other	3,265	(588)	—
At end of year	190,713,806	189,714,149	187,572,200

Note T – Business Segments

Murphy's reportable segments are organized into two major types of business activities, each subdivided into geographic areas of operations. The Company's exploration and production activity is subdivided into segments for the United States, Canada, the United Kingdom, Malaysia and all other countries; each of these segments derives revenues primarily from the sale of crude oil and/or natural gas. The Company's refining and marketing segments are North America and the United Kingdom and each derives revenue mainly from the sale of petroleum products and merchandise. The Company sells gasoline in the United States at retail stations built primarily at Walmart Supercenters. The U.S. refining and marketing business and the former Canadian marketing business are included in the North American segment. In 2007, the Company exited the gasoline marketing business in Canada by closing and writing off all eight gasoline stations in that country. The Company's management evaluates segment performance based on income from operations, excluding interest income and interest expense. Intersegment transfers of crude oil, natural gas and petroleum products are at market prices and intersegment services are recorded at cost.

Information about business segments and geographic operations is reported in the following tables. For geographic purposes, revenues are attributed to the country in which the sale occurs. The Company had no single customer from which it derived more than 10% of its revenues. Corporate and other activities, including interest income, miscellaneous gains and losses, interest expense and unallocated overhead, are shown in the tables to reconcile the business segments to consolidated totals. As used in the table on page F-32, Certain Long-Lived Assets at December 31 exclude investments, noncurrent receivables, deferred tax assets and goodwill and other intangible assets.

Excise taxes on petroleum products of $2,140,338,000, $2,070,077,000 and $1,741,707,000 for the years 2008, 2007 and 2006, respectively, that were collected by the Company and remitted to various government entities were excluded from revenues and costs and expenses.

Segment Information

(Million of dollars)	Exploration and Production U.S.	Canada	U.K.	Malaysia	Other	Total
Year ended December 31, 2008						
Segment income (loss)	$ 156.6	588.7	73.8	865.3	(81.6)	1,602.8
Revenues from external customers	529.1	1,210.0	215.8	2,000.6	1.8	3,957.3
Intersegment revenues	—	166.5	.2	—	—	166.7
Interest income	—	—	—	—	—	—
Interest expense, net of capitalization	—	—	—	—	—	—
Income tax expense (benefit)	85.8	244.7	72.9	552.9	—	956.3
Significant noncash charges (credits)						
Depreciation, depletion, amortization	110.0	139.4	28.9	248.4	1.1	527.8
Accretion of asset retirement obligations	6.2	8.3	2.4	5.9	.7	23.5
Amortization of undeveloped leases	25.2	85.9	—	—	.9	112.0
Deferred and noncurrent income taxes	25.6	(.5)	3.0	176.2	(3.2)	201.1
Additions to property, plant, equipment	366.4	470.7	31.7	664.1	163.1	1,696.0
Total assets at year-end	1,458.3	2,017.0	210.8	2,675.4	450.7	6,812.2
Year ended December 31, 2007						
Segment income (loss)	$ 98.2	370.2	47.6	148.2	(35.6)	628.6
Revenues from external customers	429.8	873.0	146.6	435.7	4.5	1,889.6
Intersegment revenues	—	130.3	.1	—	—	130.4
Interest income	—	—	—	—	—	—
Interest expense, net of capitalization	—	—	—	—	—	—
Income tax expense (benefit)	45.1	122.3	48.4	109.8	.7	326.3
Significant noncash charges (credits)						
Depreciation, depletion, amortization	74.5	183.8	20.7	57.9	.7	337.6
Accretion of asset retirement obligations	4.0	5.5	2.0	4.0	.6	16.1
Amortization of undeveloped leases	17.5	14.2	—	—	1.5	33.2
Impairment of long-lived assets	2.6	—	—	—	—	2.6
Deferred and noncurrent income taxes	35.7	(51.0)	5.6	77.0	1.5	68.8
Additions to property, plant, equipment	243.1	537.2	31.8	629.1	129.5	1,570.7
Total assets at year-end	1,130.2	2,327.8	198.9	2,110.2	431.6	6,198.7
Year ended December 31, 2006						
Segment income (loss)	$ 212.4	330.6	60.7	(5.9)	(19.4)	578.4
Revenues from external customers	626.9	674.1	180.6	219.6	3.7	1,704.9
Intersegment revenues	—	118.3	—	—	—	118.3
Interest income	—	—	—	—	—	—
Interest expense, net of capitalization	—	—	—	—	—	—
Income tax expense (benefit)	110.8	102.1	73.7	35.7	.9	323.2
Significant noncash charges (credits)						
Depreciation, depletion, amortization	85.2	114.7	22.1	47.2	.5	269.7
Accretion of asset retirement obligations	3.0	4.6	1.8	.8	.6	10.8
Amortization of undeveloped leases	17.3	3.7	—	—	1.5	22.5
Deferred and noncurrent income taxes	(5.7)	(3.9)	13.0	15.0	(.6)	17.8
Additions to property, plant, equipment	112.0	181.5	27.8	505.9	24.1	851.3
Total assets at year-end	880.2	1,761.3	185.4	1,386.0	98.6	4,311.5

Geographic Information

(Million of dollars)	Certain Long-Lived Assets at December 31 U.S.	Canada	U.K.	Malaysia	Other	Total
2008	$ 2,671.1	1,880.6	591.6	2,277.0	315.1	7,735.4
2007	2,187.5	2,103.6	678.0	1,818.4	330.4	7,117.9
2006	1,804.3	1,519.7	353.2	1,236.3	200.9	5,114.4

Segment Information (Continued)

(Millions of dollars)	Refining and Marketing North America	Refining and Marketing U.K.	Refining and Marketing Total	Corp. and Other	Discontinued Operations	Consolidated
Year ended December 31, 2008						
Segment income (loss)	$ 227.9	85.9	313.8	(171.8)	(4.8)	1,740.0
Revenues from external customers	18,927.0	4,639.1	23,566.1	(91.1)	—	27,432.3
Intersegment revenues	—	—	—	—	—	166.7
Interest income	—	—	—	40.8	—	40.8
Interest expense, net of capitalization	—	—	—	42.2	—	42.2
Income tax expense (benefit)	134.6	38.1	172.7	(55.4)	—	1,073.6
Significant noncash charges (credits)						
Depreciation, depletion, amortization	97.2	36.9	134.1	5.4	—	667.3
Accretion of asset retirement obligations	1.0	—	1.0	—	—	24.5
Amortization of undeveloped leases	—	—	—	—	—	112.0
Deferred and noncurrent income taxes	16.4	5.3	21.7	10.1	—	232.9
Additions to property, plant, equipment	341.3	84.9	426.2	3.2	—	2,125.4
Total assets at year-end	2,314.5	805.6	3,120.1	1,142.2	74.6	11,149.1
Year ended December 31, 2007						
Segment income (loss)	$ 230.4	(24.7)	205.7	(95.2)	27.4	766.5
Revenues from external customers	15,050.9	1,358.2	16,409.1	14.3	—	18,313.0
Intersegment revenues	—	—	—	—	—	130.4
Interest income	—	—	—	34.2	—	34.2
Interest expense, net of capitalization	—	—	—	24.8	—	24.8
Income tax expense (benefit)	126.3	(5.4)	120.9	2.7	—	449.9
Significant noncash charges (credits)						
Depreciation, depletion, amortization	91.2	16.8	108.0	5.0	—	450.6
Accretion of asset retirement obligations	.1	—	.1	—	—	16.2
Amortization of undeveloped leases	—	—	—	—	—	33.2
Impairment of long-lived assets	38.1	—	38.1	—	—	40.7
Deferred and noncurrent income taxes	(1.7)	1.0	(.7)	34.4	—	102.5
Additions to property, plant, equipment	321.7	250.8	572.5	4.1	—	2,147.3
Total assets at year-end	2,378.4	1,024.5	3,402.9	803.5	130.7	10,535.8
Year ended December 31, 2006						
Segment income (loss)	$ 77.5	33.1	110.6	(85.9)	41.6	644.7
Revenues from external customers	11,441.8	1,019.7	12,461.5	14.9	—	14,181.3
Intersegment revenues	—	—	—	—	—	118.3
Interest income	—	—	—	26.5	—	26.5
Interest expense, net of capitalization	—	—	—	9.5	—	9.5
Income tax expense (benefit)	39.8	15.3	55.1	(9.5)	—	368.8
Significant noncash charges (credits)						
Depreciation, depletion, amortization	70.7	13.0	83.7	3.3	—	356.7
Accretion of asset retirement obligations	.1	—	.1	—	—	10.9
Amortization of undeveloped leases	—	—	—	—	—	22.5
Deferred and noncurrent income taxes	13.0	(2.3)	10.7	4.6	—	33.1
Additions to property, plant, equipment	163.6	9.8	173.4	6.3	—	1,031.0
Total assets at year-end	2,004.3	369.6	2,373.9	652.6	145.2	7,483.2

Geographic Information

(Millions of dollars)	Revenues from External Customers for the Year U.S.	U.K.	Canada	Malaysia	Other	Total
2008	$19,352.5	4,855.1	1,222.3	2,000.6	1.8	27,432.3
2007	15,450.4	1,507.6	913.7	435.7	5.6	18,313.0
2006	12,029.5	1,203.6	724.6	219.7	3.9	14,181.3

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

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

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

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

Oil reserves in Ecuador are derived from a participation contract covering Block 16 in the Amazon region. Oil reserves associated with the participation contract in Ecuador totaled 4.8 million barrels at December 31, 2008, based on a contract expiration date of January 2012. The Company sold these Ecuador properties on March 12, 2009 (see Note C). Oil and natural gas reserves in Malaysia are associated with production sharing contracts for Blocks SK 309/311 and K. Malaysia reserves include oil and gas to be received for both cost recovery and profit provisions under the contracts. Oil and natural gas reserves associated with the production sharing contracts in Malaysia totaled 100.7 million barrels and 405.2 billion cubic feet, respectively, at December 31, 2008.

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

At December 31, 2008, proved reserves are included for several fields where development projects are ongoing, including one field in the Gulf of Mexico, a natural gas development at Tupper in British Columbia and in Malaysia for natural gas projects at Sarawak and Kikeh and an oil development at Kakap.

Synthetic oil reserves in Canada, shown in a separate table following the natural gas reserve table at Schedule 2, are attributable to Murphy's 5% share, after deducting estimated net profit royalty, of the Syncrude project and include currently producing leases. Additional reserves will be added as development progresses.

Recent SEC Reserve Changes

On December 29, 2008, the U.S. Securities and Exchange Commission adopted revisions to oil and natural gas reserve reporting requirements which are effective for the Company at year-end 2009, unless the timing is subsequently amended. Among other things, the rule:

- revises the definition of proved reserves, including the pricing used to determine economic producibility,
- expands the definition of oil and gas producing activities to include non-traditional and unconventional resources, which includes the Company's synthetic oil operations in Alberta, and
- allows, but does not require, companies to disclose probable and possible reserves in SEC filings.

The Company is currently evaluating these new rules and cannot predict how the new rules will affect its future reporting of oil and natural gas reserves.

SCHEDULE 4 – RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES – Results of operations from exploration and production activities by geographic area are reported as if these activities were not part of an operation that also refines crude oil and sells refined products.

SCHEDULE 5 – STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES – SFAS No. 69 requires calculation of future net cash flows using a 10% annual discount factor and year-end prices, costs and statutory tax rates, except for known future changes such as contracted prices and legislated tax rates. Future net cash flows from the Company's interest in synthetic oil are excluded.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future cash flows because prices, costs and governmental policies do not remain static; appropriate discount rates may vary; and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts. SFAS No. 69 requires that oil and natural gas prices as of the last business day of the year be used for calculation of the standardized measure of discounted future net cash flows.

Schedule 5 also presents the principal reasons for change in the standardized measure of discounted future net cash flows for each of the three years ended December 31, 2008.

Schedule 1 – Estimated Net Proved Oil Reserves

(Millions of barrels)	United States	Canada	United Kingdom	Malaysia	Ecuador*	Total
Proved						
December 31, 2005	48.9	45.8	23.3	47.5	16.5	182.0
Revisions of previous estimates	(2.6)	2.4	—	2.3	(2.3)	(.2)
Improved recovery	—	.3	—	—	—	.3
Purchases of properties	—	.3	—	—	—	.3
Extensions and discoveries	5.4	5.1	—	8.6	—	19.1
Production	(7.7)	(10.2)	(2.6)	(4.1)	(3.1)	(27.7)
December 31, 2006	44.0	43.7	20.7	54.3	11.1	173.8
Revisions of previous estimates	(8.9)	3.6	—	3.2	(.4)	(2.5)
Extensions and discoveries	.9	2.2	—	32.5	—	35.6
Production	(4.8)	(11.3)	(1.9)	(7.4)	(3.3)	(28.7)
December 31, 2007	31.2	38.2	18.8	82.6	7.4	178.2
Revisions of previous estimates	(1.5)	(1.9)	—	13.3	.1	10.0
Improved recovery	—	—	—	18.4	—	18.4
Extensions and discoveries	1.0	1.1	—	7.4	—	9.5
Production	(3.9)	(9.3)	(1.8)	(21.0)	(2.7)	(38.7)
Sales of properties	—	(3.8)	—	—	—	(3.8)
December 31, 2008	26.8	24.3	17.0	100.7	4.8	173.6
Proved Developed						
December 31, 2005	28.3	43.5	20.0	7.3	8.2	107.3
December 31, 2006	26.7	41.1	18.0	4.8	8.5	99.1
December 31, 2007	19.1	36.6	16.1	38.6	7.2	117.6
December 31, 2008	16.7	23.1	14.5	63.4	4.8	122.5

Schedule 2 – Estimated Net Proved Natural Gas Reserves

(Billions of cubic feet)	United States	Canada	United Kingdom	Malaysia	Total
Proved					
December 31, 2005	178.1	24.6	28.1	—	230.8
Revisions of previous estimates	(14.2)	(1.6)	—	74.6	58.8
Purchases of properties	—	2.0	—	—	2.0
Extensions and discoveries	5.4	—	—	262.9	268.3
Production	(20.7)	(4.1)	(3.7)	—	(28.5)
December 31, 2006	148.6	20.9	24.4	337.5	531.4
Revisions of previous estimates	(19.1)	7.7	—	(2.2)	(13.6)
Extensions and discoveries	.9	5.8	1.9	88.7	97.3
Production	(17.1)	(4.5)	(2.7)	—	(24.3)
December 31, 2007	113.3	29.9	23.6	424.0	590.8
Revisions of previous estimates	1.1	.8	—	(45.4)	(43.5)
Improved recovery	—	—	—	1.9	1.9
Extensions and discoveries	.8	56.0	—	25.3	82.1
Production	(17.8)	(1.8)	(2.8)	(.6)	(23.0)
Sales of properties	—	(22.7)	—	—	(22.7)
December 31, 2008	97.4	62.2	20.8	405.2	585.6
Proved Developed					
December 31, 2005	75.2	24.2	26.0	—	125.4
December 31, 2006	70.6	20.6	22.3	—	113.5
December 31, 2007	70.8	26.4	21.5	62.4	181.1
December 31, 2008	58.8	52.0	18.9	79.5	209.2

* The Company sold its Ecuador operations on March 12, 2009.

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

The Company has a 5% interest in Syncrude, the world's largest tar sands synthetic oil production project located in Alberta, Canada. In addition to conventional liquids and natural gas proved reserves, Murphy has significant proved synthetic oil reserves associated with Syncrude that are shown in the table below. For internal management purposes, Murphy views these reserves and ongoing production and development as an integral part of its total Exploration and Production operations. However, the U.S. Securities and Exchange Commission's regulations define Syncrude as a mining operation, and therefore, do not permit these synthetic oil proved reserves to be included as a part of conventional oil and natural gas reserves. These reserves are also not included in the Company's schedule of Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, which can be found on page F-41.

Synthetic Oil Proved Reserves
(Millions of barrels)

December 31, 2005	133.1
December 31, 2006	125.9
December 31, 2007	128.4
December 31, 2008	131.6

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

(Millions of dollars)	United States	Canada[1]	United Kingdom	Malaysia	Ecuador[2]	Other	Total
Year Ended December 31, 2008							
Property acquisition costs							
Unproved	$125.7	20.6	—	—	—	9.7	156.0
Proved	—	—	—	—	—	—	—
Total acquisition costs	125.7	20.6	—	—	—	9.7	156.0
Exploration costs[3]	142.4	18.8	10.2	97.2	—	61.1	329.7
Development costs[3]	168.9	421.7	27.2	687.9	6.9	152.4	1,465.0
Total costs incurred	437.0	461.1	37.4	785.1	6.9	223.2	1,950.7
Charged to expense							
Dry hole expense	18.0	—	—	80.4	—	31.1	129.5
Geophysical and other costs	40.2	18.9	.5	14.3	—	29.0	102.9
Total charged to expense	58.2	18.9	.5	94.7	—	60.1	232.4
Property additions	$378.8	442.2	36.9	690.4	6.9	163.1	1,718.3
Year Ended December 31, 2007							
Property acquisition costs							
Unproved	$ 23.4	399.2	—	—	—	—	422.6
Proved	—	—	—	—	—	—	—
Total acquisition costs	23.4	399.2	—	—	—	—	422.6
Exploration costs[3]	112.8	31.1	.8	43.9	.3	19.3	208.2
Development costs[3]	215.8	126.9	31.2	646.2	40.1	129.3	1,189.5
Total costs incurred	352.0	557.2	32.0	690.1	40.4	148.6	1,820.3
Charged to expense							
Dry hole expense	41.5	7.8	—	17.9	.3	(.4)	67.1
Geophysical and other costs	34.6	32.7	.8	15.2	—	19.5	102.8
Total charged to expense	76.1	40.5	.8	33.1	.3	19.1	169.9
Property additions	$275.9	516.7	31.2	657.0	40.1	129.5	1,650.4
Year Ended December 31, 2006							
Property acquisition costs							
Unproved	$ 13.0	.9	—	—	—	—	13.9
Proved	—	—	—	—	—	—	—
Total acquisition costs	13.0	.9	—	—	—	—	13.9
Exploration costs[3]	119.2	4.9	—	185.6	1.5	26.8	338.0
Development costs[3]	72.5	138.3	30.4	460.3	34.8	4.6	740.9
Total costs incurred	204.7	144.1	30.4	645.9	36.3	31.4	1,092.8
Charged to expense							
Dry hole expense	56.4	.2	—	52.5	1.5	.4	111.0
Geophysical and other costs	30.6	1.2	.2	46.8	—	6.9	85.7
Total charged to expense	87.0	1.4	.2	99.3	1.5	7.3	196.7
Property additions	$117.7	142.7	30.2	546.6	34.8	24.1	896.1

1 Excludes property additions for the Company's 5% interest in synthetic oil operations in Canada of $35.6 million in 2008, $23.6 million in 2007 and $42.2 million in 2006.

2 The Company sold its Ecuador operations on March 12, 2009.

3 Includes non-cash asset retirement costs as follows:

	United States	Canada	United Kingdom	Malaysia	Ecuador	Other	Total
2008							
Exploration costs	$ 6.1	—	—	—	—	—	6.1
Development costs	6.3	7.1	5.2	26.3	—	—	44.9
	$ 12.4	7.1	5.2	26.3	—	—	51.0
2007							
Exploration costs	$ 2.5	—	—	—	—	—	2.5
Development costs	30.3	3.1	(.6)	27.9	—	—	60.7
	$ 32.8	3.1	(.6)	27.9	—	—	63.2
2006							
Exploration costs	$ 2.6	—	—	(2.6)	—	—	—
Development costs	3.1	3.4	2.4	43.3	—	—	52.2
	$ 5.7	3.4	2.4	40.7	—	—	52.2

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

(Millions of dollars)	United States	Canada	United Kingdom	Malaysia	Other	Subtotal	Synthetic Oil-Canada	Total
Year Ended December 31, 2008								
Revenues								
Crude oil and natural gas liquids								
Sales to unaffiliated enterprises	$374.0	697.5	189.2	1,985.6	—	3,246.3	371.4	3,617.7
Transfers to consolidated operations	—	78.3	.2	—	—	78.5	88.2	166.7
Natural gas								
Sales to unaffiliated enterprises	162.1	5.5	25.8	.1	—	193.5	—	193.5
Total oil and gas revenues	536.1	781.3	215.2	1,985.7	—	3,518.3	459.6	3,977.9
Other operating revenues	(7.0)	133.1	.8	14.9	1.8	143.6	2.5	146.1
Total revenues	529.1	914.4	216.0	2,000.6	1.8	3,661.9	462.1	4,124.0
Costs and expenses								
Production expenses	67.0	88.6	32.9	234.4	—	422.9	188.6	611.5
Exploration costs charged to expense	58.2	18.9	.5	94.7	60.1	232.4	—	232.4
Undeveloped lease amortization	25.2	85.9	—	—	.9	112.0	—	112.0
Depreciation, depletion and amortization	110.0	111.1	28.9	248.4	1.1	499.5	28.3	527.8
Accretion of asset retirement obligations	6.2	4.4	2.4	5.9	.7	19.6	3.9	23.5
Selling and general expenses	20.1	12.6	4.6	(1.0)	20.6	56.9	.8	57.7
Total costs and expenses	286.7	321.5	69.3	582.4	83.4	1,343.3	221.6	1,564.9
	242.4	592.9	146.7	1,418.2	(81.6)	2,318.6	240.5	2,559.1
Income tax expense	85.8	169.1	72.9	552.9	—	880.7	75.6	956.3
Results of operations*	$156.6	423.8	73.8	865.3	(81.6)	1,437.9	164.9	1,602.8
Year Ended December 31, 2007								
Revenues								
Crude oil and natural gas liquids								
Sales to unaffiliated enterprises	$310.8	559.3	129.4	436.0	—	1,435.5	290.4	1,725.9
Transfers to consolidated operations	—	69.3	.1	—	—	69.4	61.0	130.4
Natural gas								
Sales to unaffiliated enterprises	121.7	23.0	16.6	—	—	161.3	—	161.3
Total oil and gas revenues	432.5	651.6	146.1	436.0	—	1,666.2	351.4	2,017.6
Other operating revenues	(2.7)	.3	.6	(.3)	4.5	2.4	—	2.4
Total revenues	429.8	651.9	146.7	435.7	4.5	1,668.6	351.4	2,020.0
Costs and expenses								
Production expenses	80.4	103.9	23.5	73.7	—	281.5	144.4	425.9
Exploration costs charged to expense	76.1	40.5	.8	33.1	19.1	169.6	—	169.6
Undeveloped lease amortization	17.5	14.2	—	—	1.5	33.2	—	33.2
Depreciation, depletion and amortization	74.5	157.3	20.7	57.9	.7	311.1	26.5	337.6
Accretion of asset retirement obligations	4.0	4.8	2.0	4.0	.6	15.4	.7	16.1
Impairment of long-lived assets	2.6	—	—	—	—	2.6	—	2.6
Selling and general expenses	31.4	17.7	3.7	9.0	17.5	79.3	.8	80.1
Total costs and expenses	286.5	338.4	50.7	177.7	39.4	892.7	172.4	1,065.1
	143.3	313.5	96.0	258.0	(34.9)	775.9	179.0	954.9
Income tax expense	45.1	79.7	48.4	109.8	.7	283.7	42.6	326.3
Results of operations*	$ 98.2	233.8	47.6	148.2	(35.6)	492.2	136.4	628.6

* Excludes corporate overhead, interest and discontinued operations.

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

(Millions of dollars)	United States	Canada	United Kingdom	Malaysia	Other	Subtotal	Synthetic Oil-Canada	Total
Year Ended December 31, 2006								
Revenues								
Crude oil and natural gas liquids								
Sales to unaffiliated enterprises	$440.1	407.4	156.8	219.6	—	1,223.9	220.3	1,444.2
Transfers to consolidated operations	—	68.6	—	—	—	68.6	49.7	118.3
Natural gas								
Sales to unaffiliated enterprises	160.4	24.1	23.3	—	—	207.8	—	207.8
Total oil and gas revenues	600.5	500.1	180.1	219.6	—	1,500.3	270.0	1,770.3
Other operating revenues	26.4	22.3	.5	—	3.7	52.9	—	52.9
Total revenues	626.9	522.4	180.6	219.6	3.7	1,553.2	270.0	1,823.2
Costs and expenses								
Production expenses	79.3	102.6	18.4	32.7	—	233.0	120.5	353.5
Exploration costs charged to expense	87.0	1.4	.2	99.3	7.3	195.2	—	195.2
Undeveloped lease amortization	17.3	3.7	—	—	1.5	22.5	—	22.5
Depreciation, depletion and amortization	85.2	97.1	22.1	47.2	.5	252.1	17.6	269.7
Accretion of asset retirement obligations	3.0	4.1	1.8	.8	.6	10.3	.5	10.8
Net costs associated with hurricanes	1.9	—	—	—	—	1.9	—	1.9
Selling and general expenses	30.0	11.4	3.7	9.8	12.3	67.2	.8	68.0
Total costs and expenses	303.7	220.3	46.2	189.8	22.2	782.2	139.4	921.6
	323.2	302.1	134.4	29.8	(18.5)	771.0	130.6	901.6
Income tax expense	110.8	72.4	73.7	35.7	.9	293.5	29.7	323.2
Results of operations*	$212.4	229.7	60.7	(5.9)	(19.4)	477.5	100.9	578.4

* Excludes corporate overhead, interest and discontinued operations.

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

(Millions of dollars)	United States	Canada[1]	United Kingdom	Malaysia	Ecuador[2]	Total
December 31, 2008						
Future cash inflows	$1,722.0	999.6	751.0	5,602.3	128.5	9,203.4
Future development costs	(330.0)	(26.3)	(133.3)	(924.8)	(4.8)	(1,419.2)
Future production and abandonment costs	(495.6)	(445.0)	(254.8)	(1,078.8)	(87.4)	(2,361.6)
Future income taxes	(217.9)	(157.0)	(201.4)	(1,336.8)	—	(1,913.1)
Future net cash flows	678.5	371.3	161.5	2,261.9	36.3	3,509.5
10% annual discount for estimated timing of cash flows	(146.1)	(62.2)	(59.6)	(572.3)	(4.1)	(844.3)
Standardized measure of discounted future net cash flows	$ 532.4	309.1	101.9	1,689.6	32.2	2,665.2
December 31, 2007						
Future cash inflows	$3,564.8	2,905.0	1,955.7	7,813.6	214.0	16,453.1
Future development costs	(397.7)	(19.1)	(73.9)	(1,504.3)	(19.9)	(2,014.9)
Future production and abandonment costs	(542.0)	(901.1)	(436.2)	(1,674.6)	(141.5)	(3,695.4)
Future income taxes	(849.8)	(434.7)	(738.7)	(1,381.6)	(15.2)	(3,420.0)
Future net cash flows	1,775.3	1,550.1	706.9	3,253.1	37.4	7,322.8
10% annual discount for estimated timing of cash flows	(489.1)	(335.9)	(272.2)	(750.5)	(3.1)	(1,850.8)
Standardized measure of discounted future net cash flows	$1,286.2	1,214.2	434.7	2,502.6	34.3	5,472.0
December 31, 2006						
Future cash inflows	$3,178.8	1,880.7	1,337.0	3,407.4	331.1	10,135.0
Future development costs	(398.8)	(17.8)	(53.7)	(672.2)	(53.8)	(1,196.3)
Future production and abandonment costs	(567.3)	(600.4)	(372.0)	(479.9)	(131.7)	(2,151.3)
Future income taxes	(624.5)	(318.1)	(468.9)	(652.5)	(48.0)	(2,112.0)
Future net cash flows	1,588.2	944.4	442.4	1,602.8	97.6	4,675.4
10% annual discount for estimated timing of cash flows	(444.0)	(177.0)	(126.0)	(385.4)	(22.1)	(1,154.5)
Standardized measure of discounted future net cash flows	$1,144.2	767.4	316.4	1,217.4	75.5	3,520.9

[1] Excludes discounted future net cash flows from synthetic oil of $545.9 million at December 31, 2008, $2,127.6 million at December 31, 2007 and $1,096.0 million at December 31, 2006.

[2] The Company sold it Ecuador operations on March 12, 2009.

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

(Millions of dollars)	2008	2007	2006
Net changes in prices, production costs and development costs	$(3,433.3)	1,130.6	(1,948.7)
Sales and transfers of oil and gas produced, net of production costs	(3,288.1)	(1,476.1)	(1,413.2)
Net change due to extensions and discoveries	825.4	1,919.6	1,026.0
Net change due to purchases and sales of proved reserves	(75.0)	—	8.8
Development costs incurred	1,245.0	936.0	645.2
Accretion of discount	798.5	508.8	613.6
Revisions of previous quantity estimates	164.0	(121.8)	20.7
Net change in income taxes	956.7	(946.0)	379.5
Net increase (decrease)	(2,806.8)	1,951.1	(668.1)
Standardized measure at January 1	5,472.0	3,520.9	4,189.0
Standardized measure at December 31	$ 2,665.2	5,472.0	3,520.9

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

(Millions of dollars)	United States	Canada	United Kingdom	Malaysia	Ecuador*	Other	Subtotal	Synthetic Oil-Canada	Total
December 31, 2008									
Unproved oil and gas properties	$ 313.5	405.2	9.6	198.5	—	243.7	1,170.5	—	1,170.5
Proved oil and gas properties	1,419.0	1,620.3	495.5	2,504.2	388.0	3.5	6,430.5	832.1	7,262.6
Gross capitalized costs	1,732.5	2,025.5	505.1	2,702.7	388.0	247.2	7,601.0	832.1	8,433.1
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	(59.3)	(93.2)	—	—	—	(9.7)	(162.2)	—	(162.2)
Proved oil and gas properties	(543.7)	(719.4)	(312.9)	(430.8)	(317.3)	(3.5)	(2,327.6)	(165.3)	(2,492.9)
Net capitalized costs	$1,129.5	1,212.9	192.2	2,271.9	70.7	234.0	5,111.2	666.8	5,778.0
December 31, 2007									
Unproved oil and gas properties	$ 216.9	483.1	—	191.2	—	223.9	1,115.1	—	1,115.1
Proved oil and gas properties	1,154.2	1,831.0	468.2	1,823.0	381.1	3.6	5,661.1	911.2	6,572.3
Gross capitalized costs	1,371.1	2,314.1	468.2	2,014.2	381.1	227.5	6,776.2	911.2	7,687.4
Accumulated depreciation, depletion and amortization									
Unproved oil and gas properties	(48.4)	(27.5)	—	—	—	(8.8)	(84.7)	—	(84.7)
Proved oil and gas properties	(435.9)	(923.7)	(287.7)	(203.0)	(274.6)	(3.6)	(2,128.5)	(171.3)	(2,299.8)
Net capitalized costs	$ 886.8	1,362.9	180.5	1,811.2	106.5	215.1	4,563.0	739.9	5,302.9

* The Company sold its Ecuador operations on March 12, 2009.

Note: Unproved oil and gas properties above include costs and associated accumulated amortization of properties that do not have proved reserves; these costs include mineral interests, uncompleted exploratory wells, and exploratory wells capitalized pending further evaluation.

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

(Millions of dollars except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Year Ended December 31, 2008					
Sales and other operating revenues	$ 6,466.7	8,249.2	8,184.7	4,460.0	27,360.6
Income from continuing operations before income taxes	656.7	968.5	919.4	273.8	2,818.4
Income from continuing operations	408.2	618.5	585.0	133.0	1,744.7
Net income	409.0	619.2	584.4	127.4	1,740.0
Income from continuing operations per Common share					
Basic	2.16	3.26	3.08	.70	9.20
Diluted	2.13	3.22	3.04	.69	9.08
Net income per Common share					
Basic	2.16	3.27	3.08	.67	9.18
Diluted	2.14	3.22	3.04	.67	9.06
Cash dividend per Common share	.1875	.1875	.25	.25	.875
Market price of Common Stock*					
High	85.85	98.05	100.93	61.23	100.93
Low	69.54	83.03	60.61	37.00	37.00
Year Ended December 31, 2007					
Sales and other operating revenues	$ 3,402.2	4,577.5	4,736.7	5,581.2	18,297.6
Income from continuing operations before income taxes	192.9	387.6	300.8	307.7	1,189.0
Income from continuing operations	106.5	240.4	189.2	203.0	739.1
Net income	110.6	250.3	199.5	206.1	766.5
Income from continuing operations per Common share					
Basic	.57	1.28	1.01	1.07	3.93
Diluted	.56	1.26	.99	1.06	3.87
Net income per Common share					
Basic	.59	1.33	1.06	1.09	4.08
Diluted	.58	1.32	1.04	1.07	4.01
Cash dividend per Common share	.15	.15	.1875	.1875	.675
Market price of Common Stock*					
High	54.79	60.99	70.05	85.38	85.38
Low	45.93	53.16	57.90	67.97	45.93

* Prices are as quoted on the New York Stock Exchange.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SCHEDULE II – VALUATION ACCOUNTS AND RESERVES

(Millions of dollars)	Balance at January 1	Charged (Credited) to Expense	Deductions	Other*	Balance at December 31
2008					
Deducted from asset accounts:					
Allowance for doubtful accounts	**$ 7.5**	**.1**	**(.2)**	**(.1)**	**7.3**
Deferred tax asset valuation allowance	**214.1**	**52.7**	—	—	**266.8**
2007					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 10.4	.7	(3.6)	—	7.5
Deferred tax asset valuation allowance	205.8	8.3	—	—	214.1
2006					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 14.5	.3	(4.6)	.2	10.4
Deferred tax asset valuation allowance	151.1	54.7	—	—	205.8

* Amounts primarily represent changes in foreign currency exchange rates.

GLOSSARY OF TERMS

3D seismic

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

bitumen or oil sands

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

deepwater

offshore location in greater than 1,000 feet of water

downstream

refining and marketing operations

dry hole

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

exploratory

wildcat and delineation, e.g., exploratory wells

feedstock

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

hydrocarbons

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

throughput

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

upstream

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

wildcat

well drilled to target an untested or unproved geologic formation

EXHIBIT 12.1

Murphy Oil Corporation and Consolidated Subsidiaries

Computation of Ratio of Earnings to Fixed Charges (unaudited)

(Thousands of dollars)

	Six Months Ended June 30, 2009	Years Ended December 31,[1]				
		2008	2007	2006	2005	2004
Income from continuing operations before income taxes	$ 427,660	$2,818,365	1,189,004	971,883	1,319,386	800,106
Distributions (less than) greater than equity in earnings of affiliates	2,863	1,012	294	(4,065)	(5,514)	(4,225)
Previously capitalized interest charged to earnings during period	11.930	21,898	14,585	11,741	15,564	14,065
Interest and expense on indebtedness, excluding capitalized interest	2,722	42,153	25,612	9,476	8,765	34,064
Interest portion of rentals[2]	14,130	29,174	13,554	14,021	9,397	7,908
Earnings before provision for taxes and fixed charges	$ 459,305	$2,912,602	1,243,049	1,003,056	1,347,598	851,918
Interest and expense on indebtedness, excluding capitalized interest	2,722	42,153	25,612	9,476	8,765	34,064
Capitalized interest	22,450	31,459	49,881	43,073	38,539	22,160
Interest portion of rentals[2]	14,130	29,174	13,554	14,021	9,397	7,908
Total fixed charges	$ 39,302	$ 102,786	89,047	66,570	56,701	64,132
Ratio of earnings to fixed charges	11.7	28.3	14.0	15.1	23.8	13.3

1 Prior years reclassified to conform to current presentation.

2 Calculated as one-third of rentals. Considered a reasonable approximation of interest factor.

Exhibit 23

Consent of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
of Murphy Oil Corporation:

We consent to the incorporation by reference in the registration statements (Nos. 333-142789 and 333-157107) on Form S-8 of Murphy Oil Corporation of our report dated February 27, 2009, except for the effects of discontinued operations as discussed in Note C which is dated September 2, 2009, with respect to the consolidated balance sheets of Murphy Oil Corporation and subsidiaries as of December 31, 2008 and 2007 and the related consolidated statements of income, comprehensive income, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2008, and related financial statement schedule, which report appears in the Form 8-K of Murphy Oil Corporation dated September 2, 2009.

Our report refers to changes in the methods of accounting for recognition of defined benefit pension and other postretirement plans in 2006, and to changes in the method of accounting for uncertain tax positions and measurement of defined benefit pension and other postretirement plans in 2007.

KPMG LLP

Dallas, Texas
September 2, 2009