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):

November 6, 2003

Amerada Hess Corporation

(Exact name of Registrant as Specified in Charter)

Delaware	**No. 1-1204**	**No. 13-4921002**
(State or Other Jurisdiction of Incorporation)	*(Commission File Number)*	*(IRS Employer Identification No.)*

1185 Avenue of the Americas **New York, New York**	**10036**
(Address of Principal Executive Offices)	*(Zip Code)*

Registrant's telephone number, including area code:

(212) 997-8500

N/A

(Former Name or Former Address, if Changed Since Last Report)

Item 5. ***Other Events and Regulation FD Disclosure.***

This report on Form 8-K is filed to update certain financial information reported in the Corporation's 2002 Form 10-K to conform with the presentation used in 2003 for an asset exchange and certain asset sales that were accounted for as discontinued operations. During 2003, the Corporation exchanged its interests in producing properties in Colombia for an increased interest in a non-producing property under development in the joint development area of Malaysia and Thailand. The Corporation also sold producing properties in the Gulf of Mexico Shelf, the Jabung Field in Indonesia and several small United Kingdom fields. Accordingly, reclassifications for discontinued operations have been made in the consolidated financial statements, notes to the financial statements, supplementary oil and gas data, selected financial data and management's discussion and analysis of results of operations and financial condition ("MD&A").

In connection with the effective date of Regulation G on March 28, 2003, the Corporation also eliminated the presentation of certain items previously characterized as "special items" in its MD&A and notes to the financial statements.

As part of its initiative to monitor the public filings of Fortune 500 companies, the Staff of the Division of Corporation Finance of the Securities and Exchange Commission reviewed and commented on the Corporation's Form 10-K for the year ended December 31, 2001 and certain quarterly and current reports on Forms 10-Q and 8-K filed or furnished thereafter. The Staff also issued several comments on the Corporation's December 31, 2002 Form 10-K.

This review has been completed and as a result of the review, during 2003 the Corporation expanded certain disclosures in its MD&A and notes to the financial statements included in Forms 10-Q filed for the quarters ended March 31 and June 30, 2003. These disclosures primarily related to critical accounting policies concerning the determination of the Corporation's operating segments, its reporting unit for the purpose of recording goodwill and the methodology for calculating asset impairment and goodwill impairment. The Corporation has also expanded disclosures in MD&A about the crude oil reserves of the Ceiba Field and reclassified reserves from "improved recovery" to "revisions of previous estimates" in the Oil and Gas Reserves table included in the Supplementary Oil and Gas Data for 2002 filed as Exhibit 99(1). An advisory disclosure about a potential accounting interpretation that may require the balance sheet reclassification of oil and gas mineral rights is also included in MD&A and the notes to financial statements. The Corporation is also refiling the report of the independent auditors with respect to the financial statements of its 50%-owned refining joint venture, HOVENSA L.L.C., to include the city and state of the independent auditors' opinion.

The effect of discontinued operations, compliance with Regulation G and the expanded disclosures mentioned above are reflected in the financial statements, notes to the financial statements, MD&A and selected financial data in the Corporation's 2002 Form 10-K in this report on Form 8-K.

Item 7. ***Financial Statements and Exhibits.***

This report contains the following exhibits:

Amerada Hess Corporation's Selected Financial Data for the periods ended December 31, 2002, Management's Discussion and Analysis of Results of Operations and Financial Condition and Quantitative and Qualitative Disclosures About Market Risk for the year ended December 31, 2002, and Financial Statements at and for the periods ended December 31, 2002 and Supplementary Data for 2002.

(c) Exhibits

23	Consent of Independent Auditors
99(1)	Selected Financial Data for the periods ended December 31, 2002
	Management’s Discussion and Analysis of Financial Condition and Results of Operations for the year ended December 31, 2002
	Financial Statements and Supplementary Data
	Consolidated Balance Sheet at December 31, 2002 and 2001
	Statement of Consolidated Income for each of the three years in the period ended December 31, 2002
	Statement of Consolidated Retained Earnings for each of the three years in the period ended December 31, 2002
	Statement of Consolidated Cash Flows for each of the three years in the period ended December 31, 2002
	Statement of Consolidated Changes in Preferred Stock, Common Stock and Capital in Excess of Par Value for each of the three years in the period ended December 31, 2002
	Statement of Consolidated Comprehensive Income for each of the three years in the period ended December 31, 2002
	Notes to Consolidated Financial Statements
	Report of Ernst & Young LLP, Independent Auditors
	Quarterly Financial Data
	Supplementary Oil and Gas Data
99(2)	Report of Ernst & Young LLP, independent auditors, on the Financial Statements at December 31, 2002 and 2001 and for the three years ended December 31, 2002 of HOVENSA L.L.C., a 50% owned joint venture that owns and operates a refinery in the Virgin Islands

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.

AMERADA HESS CORPORATION

By: /s/ JOHN B. HESS

Name: John B. Hess
Title: Chairman of the Board and Chief Executive Officer

By: /s/ JOHN Y. SCHREYER

Name: John Y. Schreyer
Title: Executive Vice President and Chief Financial Officer

Date: November 6, 2003

EXHIBIT INDEX

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Exhibit 23

CONSENT OF INDEPENDENT AUDITORS

We hereby consent to the use of our report dated February 21, 2003 (except for Note 19, as to which the date is November 6, 2003) relating to the consolidated financial statements of Amerada Hess Corporation, and our report dated February 21, 2003 relating to the financial statements of HOVENSA, L.L.C., which appear in this Current Report on Form 8-K of Amerada Hess Corporation.

We also consent to the incorporation by reference in the Registration Statements (Form S-8, Nos. 333-94851, 333-43569, 333-43571 and 33-65115) pertaining to the Amerada Hess Corporation Employees' Savings and Stock Bonus Plan, Amerada Hess Corporation Savings and Stock Bonus Plan for Retail Operations Employees and the 1995 Long-Term Incentive Plan included in this Current Report on Form 8-K.

Ernst + Young LLP

New York, NY

November 6, 2003

Exhibit 99(1)

Amerada Hess Corporation and Consolidated Subsidiaries

Management's Discussion and Analysis of

Results of Operations and Financial Condition

Consolidated Results of Operations

In 2003, the Corporation exchanged its interests in producing properties in Colombia for an increased interest in a non-producing property under development in the joint development area of Malaysia and Thailand. The Corporation also sold certain producing properties in the Gulf of Mexico Shelf, the Jabung Field in Indonesia and several small United Kingdom fields. The after-tax results of operations from these oil and gas fields have been reclassified and reported in discontinued operations for the periods presented.

The Corporation had a loss of $218 million in 2002 compared with net income of $914 million in 2001 and $1,023 million in 2000. In 2002, the Corporation recorded non-cash impairment charges totaling $737 million after tax ($1,024 million before income taxes) to reduce the carrying value of a producing field in Equatorial Guinea and producing properties and exploration acreage in the United States. Income (loss) from continuing operations amounted to a loss of $245 million in 2002, compared with income of $816 million in 2001 and $917 million in 2000.

The after-tax results by major operating activity for 2002, 2001 and 2000 are summarized below:

	2002	2001	2000
		(Millions of dollars, except per share data)	
Exploration and production	$ (102)	$ 796	$ 762
Refining and marketing	85	233	264
Corporate	(63)	(78)	17
Interest expense	(165)	(135)	(126)
Income (loss) from continuing operations	(245)	816	917
Discontinued operations	27	98	106
Net income (loss)	$ (218)	$ 914	$1,023
Income (loss) per share from continuing operations (diluted)	$(2.78)	$ 9.15	$10.20
Net income (loss) per share (diluted)	$(2.48)	$10.25	$11.38

In the discussion which follows, the financial effects of certain transactions are disclosed on an after-tax basis. Management reviews segment earnings on an after-tax basis and uses after-tax amounts in its review of variances in segment earnings. Such after-tax amounts may be considered to be non-GAAP (Generally Accepted Accounting Principles) financial measures. Management believes that they are a preferable method of explaining variances in earnings, since they show the entire effect of a transaction rather than only the pre-tax amount. After-tax amounts are determined by applying the appropriate income tax rate in each tax jurisdiction to pre-tax amounts.

Comparison of Results

Exploration and Production:

Exploration and production earnings from continuing operations include the following items:

	After Income Taxes			Before Income Taxes		
	2002	2001	2000	2002	2001	2000
	(Millions of dollars)					
Asset impairments	$(737)	$ —	$ —	$(1,024)	$ —	$ —
Charge for increase in United Kingdom income tax rate	(43)	—	—	—	—	—
Net gain from asset sales	34	—	—	41	—	—
Charge related to Enron bankruptcy	—	(19)	—	—	(29)	—
Severance accrual	—	(10)	—	—	(15)	—
	$(746)	$(29)	$ —	$ (983)	$(44)	$ —

In addition to these items, the decrease in exploration and production earnings in 2002 compared with 2001 was primarily due to higher after-tax depreciation, depletion and amortization expenses, of approximately $158 million ($282 million before income taxes) partially offset by increased crude oil sales volumes which improved earnings by approximately $75 million after income taxes ($130 million before income taxes). The remainder of the decrease was due to lower natural gas selling prices and higher income taxes. Exploration and production earnings increased in 2001 compared with 2000, largely due to higher crude oil and natural gas sales volumes.

The Corporation's average selling prices, from continuing operations, including the effects of hedging, were as follows:

	2002	2001	2000
Crude oil (per barrel)			
United States	$24.04	$23.38	$23.70
Foreign	24.69	24.50	25.32
Natural gas liquids (per barrel)			
United States	16.12	18.76	22.28
Foreign	19.09	18.99	23.41
Natural gas (per Mcf)			
United States	3.72	4.02	3.73
Foreign	2.03	2.55	2.20

The Corporation's net daily worldwide production was as follows:

	2002	2001	2000
Crude oil (thousands of barrels per day)			
United States	54	63	55
Foreign	250	212	185
Total	304	275	240
Natural gas liquids (thousands of barrels per day)			
United States	12	14	12
Foreign	9	9	9
Total	21	23	21

	2002	2001	2000
Natural gas (thousands of Mcf per day)			
United States	373	424	288
Foreign	381	388	391
Total	754	812	679
Barrels of oil equivalent(*)(**) (thousands of barrels per day)	451	433	374
(*)Production related to discontinued operations	51	45	26

(**) Reflects natural gas production converted on the basis of relative energy content (six Mcf equals one barrel).

The Corporation's oil and gas production, on a barrel of oil equivalent basis, increased by 4% in 2002 and 16% in 2001. Amounts produced in 2002 and 2001 included production from fields acquired in Equatorial Guinea, Colombia and the United States. Production from these fields amounted to 83,000 and 43,000 barrels of oil equivalent per day in 2002 and 2001, respectively.

The Corporation presently estimates that its 2003 barrel of oil equivalent production will be approximately 20% less than its 2002 production. Approximately one-third of the expected decrease from 451,000 barrels of oil equivalent per day produced in 2002 is due to asset sales and exchanges. The remainder reflects natural decline from mature fields in the United States and United Kingdom and reduced production from the Ceiba field in Equatorial Guinea.

Depreciation, depletion and amortization charges relating to exploration and production activities increased by $282 million (before income taxes) in 2002 and $151 million in 2001. The increases result from higher unit costs, due to the amortization of the purchase price of fields acquired in Equatorial Guinea and the United States, and increased production volumes. Production expenses also increased in 2002 and 2001. The increase in 2002 was principally due to increased production from fields with higher costs, including workovers and other maintenance, and higher production volumes. In 2001, the increase in production expense was largely due to higher production volumes. Exploration expense decreased in 2002 compared with 2001, principally reflecting improved drilling results. In 2001, exploration expense was higher than in 2000, due to increased drilling and seismic purchases. General and administrative expenses related to exploration and production activities decreased in 2002, reflecting cost reduction initiatives. Exploration and production general and administrative expenses were comparable in 2001 and 2000. The total cost per barrel of oil equivalent produced (including depreciation, depletion and amortization, production expense, exploration expense and administrative costs) was $15.11 in 2002, $13.11 in 2001 and $11.84 in 2000. Total unit cost per barrel is expected to increase in 2003, primarily due to the decrease in production.

During 2002, the United Kingdom government enacted a 10% supplementary tax on profits from oil and gas production. A one-time charge of $43 million was recorded to increase the existing United Kingdom deferred tax liability on the balance sheet. In addition to this deferred tax effect, the supplementary tax reduced 2002 earnings by approximately $37 million and is expected to reduce future earnings by approximately $60 million annually (based on 2002 production volumes and prices). In 2001, exploration and production earnings included $48 million of income from the resolution of a United Kingdom income tax dispute. The effective income tax rate is expected to increase to approximately 50% in 2003, reflecting a full year of the supplementary U.K. tax and a change in mix of producing fields.

In 2002, exploration and production earnings included after-tax asset impairments of $737 million ($1,024 million before income taxes), $530 million of which related to the Ceiba Field in Equatorial Guinea. The pre-tax amount of the Ceiba Field impairment was $706 million. The charge resulted from a 12% reduction in the estimated total field reserves that will ultimately be produced from the field, as well as higher anticipated development costs needed to produce the remaining reserves at lower production rates over a longer time frame. The reduction in estimated recoverable reserves was attributable to disappointing year-end drilling results on the western flank of the field. The reduction in recoverable reserves and higher estimated future development costs resulted in projected discounted cash flows which were less than the book value of the field, which includes allocated purchase price from the Triton acquisition.

The amount of Ceiba field proved reserves was about the same at the end of 2002 as the amount at the beginning of the year (excluding 2002 production) and, therefore, the 12% reduction in total field reserves resulted from a decrease in probable reserves. The net proved reserves did not change in 2002 as a result of the recognition of a more efficient primary recovery factor than previously estimated, and to a lesser extent the positive impact of the initiation of water injection operations in February 2002 to maintain reservoir pressure, and additional drilling.

The Corporation also recorded an after-tax impairment charge of $207 million ($318 million before income taxes) to reduce the carrying value of oil and gas properties located primarily in the Main Pass/Breton Sound area of the Gulf of Mexico. Most of these properties were obtained in the 2001 LLOG acquisition and consist of producing oil and gas fields with proved and probable reserves and exploration acreage. This charge principally reflects reduced reserve estimates on these fields resulting from unfavorable production performance. The fair values of production properties were determined by using discounted cash flows. Exploration properties were evaluated by using results of drilling and production data from nearby fields and seismic data for these and other properties in the area.

A net gain of $34 million ($41 million before income taxes) was recorded during 2002 from sales of oil and gas producing properties in the United States, United Kingdom and Azerbaijan, and the Corporation's energy marketing business in the United Kingdom.

In 2001, the Corporation recorded an after-tax charge of $19 million ($29 million before income taxes) for estimated losses due to the bankruptcy of certain subsidiaries of Enron Corporation. In addition, the Corporation recorded a net charge of $10 million ($15 million before income taxes) for severance expenses resulting from cost reduction initiatives. Approximately 150 positions were eliminated.

The Corporation's future exploration and production earnings may be impacted by volatility in the selling prices of crude oil and natural gas, reserve and production changes, tax increases, local political disruptions and world events. The Corporation has hedged most of its 2003 production to mitigate volatility in selling prices.

Refining and Marketing: Earnings from continuing operations of refining and marketing activities amounted to $85 million in 2002, $233 million in 2001 and $264 million in 2000. Refining and marketing earnings from continuing operations include the following items:

	After Income Taxes			Before Income Taxes		
	2002	2001	2000	2002	2001	2000
	(Millions of dollars)					
Net gain from asset sales	$ 67	$—	$ —	$102	$—	$ —
Reduction in carrying value of intangible assets	(14)	—	—	(22)	—	—
Severance accrual	(8)	(2)	—	(13)	(3)	—
Cost associated with research and development venture	—	—	(24)	—	—	(38)
	$ 45	$ (2)	$(24)	$ 67	$ (3)	$(38)

The Corporation's downstream operations include HOVENSA L.L.C. (HOVENSA), a 50% owned refining joint venture with a subsidiary of Petroleos de Venezuela S.A. (PDVSA), accounted for on the equity method. Additional refining and marketing activities include a fluid catalytic cracking facility in Port Reading, New Jersey, as well as retail gasoline stations, energy marketing and trading operations.

HOVENSA: The Corporation's share of HOVENSA's 2002 loss was $47 million compared with income of $58 million in 2001 and $121 million in 2000. The decrease in 2002 represents lower refining margins and reduced crude runs resulting from political disturbances in Venezuela, HOVENSA's principal source of crude oil. In connection with the startup of new coking facilities in 2002, HOVENSA reduced its inventory of high sulfur crude oil. Consequently, LIFO inventory cost, which was lower than current cost, was included in 2002 cost of sales. This reduced the Corporation's share of HOVENSA's loss by approximately $15 million. The decrease in HOVENSA's 2001 earnings compared with 2000 was primarily due to turnarounds at the fluid catalytic cracking unit and a crude unit which resulted in lower charge rates and increased operating expenses. Income taxes (benefits) on the Corporation's share of HOVENSA's results are not recorded due to available loss carryforwards.

The Corporation's share of HOVENSA's crude runs amounted to 181,000 barrels per day in 2002, 202,000 in 2001 and 211,000 in 2000. The coker at HOVENSA is running at the rate of approximately 58,000 barrels per day.

Operating earnings from refining and marketing activities also include interest income on the note received from PDVSA at the formation of the joint venture. Interest on the PDVSA note amounted to $35 million in 2002, $39 million in 2001 and $48 million in 2000. Interest is reflected in non-operating income in the income statement.

Effective October 2002, the Corporation cancelled the $125 million contingent note of PDVSA, issued to it in connection with the formation of HOVENSA. At the same time, there were amendments of certain contracts relating to the HOVENSA joint venture, including a six-year extension of the contract for the supply of Mesa crude oil and an amendment to the pricing formula for Merey crude oil supplied by an affiliate of PDVSA. There was also an amendment to the services agreement between the Corporation and HOVENSA. The contingent note was not valued for accounting purposes and its cancellation had no effect on the Corporation's financial condition.

Retail, Energy Marketing and Other: Retail gasoline operations in 2002 were profitable, but less so than in 2001, reflecting lower margins. In 2001, retail results were substantially better than in 2000, due to higher margins and increased sales volumes. Energy marketing activities were also profitable in 2002 compared with a loss in 2001. Earnings from the Corporation's catalytic cracking facility in New Jersey decreased in 2002, due to lower refining margins. Earnings from the catalytic cracking facility in 2001 exceeded those from 2000, reflecting higher margins and a shutdown for scheduled maintenance in 2000. Total refined product sales volumes were 140 million barrels in 2002, 141 million barrels in 2001 and 134 million barrels in 2000.

The Corporation has a 50% voting interest in a consolidated partnership that trades energy commodities and energy derivatives. The Corporation also takes trading positions in addition to its hedging program. The Corporation's after-tax results from trading activities, including its share of the earnings of the trading partnership, amounted to income of $3 million in 2002, $45 million in 2001 and $22 million in 2000 ($6 million, $72 million and $37 million before income taxes, respectively).

Marketing expenses increased in 2002 and 2001, principally reflecting expanded retail operations. The expenses of the trading partnership are also included in marketing expenses and contributed to the increase.

In the third quarter of 2002, the Corporation completed the sale of six United States flag vessels for $161 million in cash and a note for $29 million. The sale resulted in a net gain of $67 million ($102 million before income taxes). The Corporation has agreed to support the buyer's charter rate for these vessels for up to five years. A pre-tax gain of $50 million has been deferred as part of the sale transaction to reflect potential obligations under the support agreement. Under the support agreement, if the actual contracted rate for the charter of a vessel is less than the stipulated charter rate in the agreement for such vessel, the Corporation is required to pay to the buyer the difference between the contracted rate and the stipulated rate for each vessel. If the actual contracted rate exceeds the stipulated rate, the buyer must apply such amount to reimburse the Corporation for any payments made by it up to that date. While the Corporation's eventual obligations under the support agreement could exceed the amount of the deferred gain, based on current charter rates the amount recorded is appropriate. During 2002, the Corporation paid $2 million relating to this support agreement.

The Corporation also recorded an after-tax charge of $14 million ($22 million before income taxes) in 2002 for the write-off of intangible assets in its U.S. energy marketing business. In addition, after-tax accrued severance of $8 million ($13 million before income taxes) was recorded for cost reduction initiatives in refining and marketing, principally in energy marketing. Approximately 165 positions were eliminated and an office was closed. The estimated annual savings from the staff reductions is $10 million, after-tax ($15 million before income taxes).

In 2000, the Corporation recorded a charge of $24 million ($38 million before income taxes) for costs associated with an alternative fuel research and development venture.

Refining and marketing results will continue to be volatile, reflecting competitive industry conditions and supply and demand factors, including the effects of weather.

Corporate: After-tax corporate expenses amounted to $63 million in 2002 and $78 million in 2001 compared with income of $17 million in 2000. Net corporate expenses in 2000 included a gain of $60 million ($97 million before income taxes) relating to the termination of a proposed acquisition of another oil company. In 2002, corporate administrative expenses before income taxes were comparable to the 2001 amount. The decrease in after tax expenses in 2002 reflects lower United States taxes on foreign source income. The increase in expenses in 2001 reflects the absence of the gain on termination of the acquisition in 2000, increases in certain administrative expenses, including officer severance and charitable contributions, as well as increased income taxes related to foreign operations. In 2000, the after-tax gain of $60 million on termination of a proposed acquisition principally reflected income on foreign currency contracts purchased in anticipation of the acquisition. This gain also included income from a fee on termination of the acquisition, partially offset by transaction costs.

Interest: After-tax interest was $165 million in 2002, $135 million in 2001 and $126 million in 2000 ($256 million, $194 million and $162 million before income taxes, respectively). The increase in both years is due to increased borrowings related to acquisitions, partially offset by lower interest rates and higher amounts capitalized. Capitalized interest, before income taxes, was $101 million, $44 million and $3 million in 2002, 2001 and 2000. Interest expense in 2003 is expected to be comparable to the 2002 amount. Although average debt outstanding is expected to be lower in 2003, the amount of interest capitalized is also expected to be reduced.

Discontinued Operations: In 2003, the Corporation exchanged its crude oil producing properties in Colombia, plus $10 million in cash, for an additional 25% interest in Block A-18 in the joint development area of Malaysia and Thailand. The exchange resulted in a charge to income in the first quarter of 2003 of $47 million, after-tax ($51 million before income taxes), which the Corporation reported as a loss from discontinued operations. In addition, the Corporation sold Gulf of Mexico Shelf properties, the Jabung Field in Indonesia and several small United Kingdom fields for $445 million. An after-tax gain from these asset sales of $175 million ($248 million before income taxes) was included in discontinued operations in the second quarter of 2003. Net income in 2002, 2001 and 2000 included $27 million, $98 million and $106 million from these discontinued operations. The 2002 amount included an after-tax impairment charge of approximately $49 million ($76 million before income taxes).

Consolidated Operating Revenues: Sales and other operating revenues decreased by 12% compared with 2001, due to the sale of the United Kingdom energy marketing business, and lower sales volumes of refined products and purchased natural gas related to U.S. energy marketing activities. These decreases were partially offset by higher production of crude oil and natural gas. In 2001, sales and other operating revenues increased by 11% compared with 2000. The increase was primarily due to higher sales volumes of purchased natural gas related to energy marketing activities in the United States, as well as increased refined products sales. Crude oil and natural gas production volumes were also higher.

Liquidity and Capital Resources

Net cash provided by operating activities, including changes in operating assets and liabilities, amounted to $1,965 million in 2002, $1,960 million in 2001 and $1,795 million in 2000. Although the Corporation's earnings in 2002 were lower than in 2001, the decrease was primarily due to impairment charges and higher depreciation, depletion and amortization expenses which are non-cash charges. As a result, net cash provided by operating activities in 2002 was comparable to that of 2001. Assuming average 2002 oil and gas selling prices and excluding changes in working capital and proceeds from asset sales, the Corporation anticipates that operating cash flow will decline in 2003 by approximately 30% and, therefore, less cash flow will be available for financial management purposes, including debt reduction. This decline is primarily due to lower anticipated production in 2003.

A portion of the lower anticipated production results from reduced proved reserve estimates on the LLOG fields acquired in 2001 and a reduction of probable reserves and an extended field life with lower planned production rates on the Ceiba field, also acquired in 2001. The reduced production and reserves will result in lower than expected cash flows and growth from these fields over the next several years, assuming average 2002 oil and gas prices.

In 2002, the Corporation sold United States flag vessels, its energy marketing business in the United Kingdom and several small oil and gas fields for net proceeds of $412 million.

In the first quarter of 2003, the Corporation also completed the sale of its 1.5% interest in the Trans Alaska Pipeline System and will record a net gain of approximately $30 million. The Corporation also entered into an agreement during 2002 with Premier Oil plc to exchange its 25% shareholding interest in Premier, plus $17 million in cash, for a 23% interest in Natuna Sea Block A in Indonesia. Completion of the transaction is conditional upon certain governmental consents. The Corporation does not expect a material income statement impact from this transaction.

The balances in accounts receivable, as well as accounts payable and accrued liabilities, are substantially lower at December 31, 2002 than at December 31, 2001. Consolidated revenues are also lower and certain expenses, including marketing expenses, are lower than they otherwise would have been. These decreases are largely due to the sale of the United Kingdom energy marketing business in the first quarter of 2002.

Total debt was $4,992 million at December 31, 2002 compared with $5,665 million at December 31, 2001. The Corporation's debt to capitalization ratio was 54.0% at December 31, 2002 compared with 53.6% at the prior year-end. Debt reduction of $673 million in 2002 did not reduce the debt to capitalization ratio, because of the net loss in 2002 and required reduction in stockholder's equity for the pension plan and deferred hedging losses recorded in accumulated other comprehensive income.

Loan agreement covenants allow the Corporation to borrow an additional $1.9 billion for the construction or acquisition of assets at December 31, 2002. At year-end, the amount that can be borrowed under the loan agreements for the payment of dividends is $720 million. At December 31, 2002, the Corporation has $1.5 billion of additional borrowing capacity available under its revolving credit agreements and has additional unused lines of credit for $206 million under uncommitted arrangements with banks.

Following is a table showing aggregated information about certain contractual obligations at December 31, 2002:

		Payments Due by Period			
	Total	2003	2004 and 2005	2006 and 2007	Thereafter
			(Millions of dollars)		
Short-term notes	$ 2	$ 2	$ —	$ —	$ —
Long-term debt, including capital leases	4,990	14	623	826	3,527
Operating leases	1,297	107	166	131	893
Purchase obligations					
Supply commitments	12,143	4,196	3,986	3,961	*
Capital expenditures	194	164	30	—	—
Operating expenses	429	225	101	63	40
Other long-term liabilities	215	14	132	12	57

* The Corporation intends to continue purchasing its refined product supply from HOVENSA. Current purchases amount to approximately $2 billion annually.

The Corporation has leveraged lease financings not included in its balance sheet primarily related to retail gasoline station leases. The commitments under these leases are included in the operating lease obligations shown in the accompanying table. The net present value of the financings is $449 million at December 31, 2002, using interest rates inherent in the leases. The Corporation's December 31, 2002 debt to capitalization ratio would increase from 54.0% to 56.2% if the leveraged lease financings were included.

In the preceding table, the Corporation's supply commitments include its estimated purchases of 50% of HOVENSA's production of refined products, after anticipated sales by HOVENSA to unaffiliated parties. Also included are normal term purchase agreements for additional gasoline necessary to supply the Corporation's retail marketing system and feedstocks for the Port Reading refining facility. In addition, the Corporation has commitments to purchase natural gas for use in supplying contracted customers in its energy marketing business. These commitments were computed based on year-end market prices.

The table also reflects that portion of the Corporation's planned capital expenditures which are contractually committed at December 31. The Corporation's 2003 capital expenditures are estimated to be $1,475 million and are more fully explained below. Obligations for operating expenses include commitments for transportation, seismic purchases, oil and gas production expenses and other normal business expenses. Other long-term liabilities reflect contractually committed obligations on the balance sheet at December 31, including minimum pension plan funding requirements.

None of the Corporation's debt or lease obligations would be terminated, nor would principal or interest payments be accelerated, as a result of a credit rating downgrade. However, if the Corporation's credit rating were reduced below its present level, certain fees and interest rates would increase and certain contracts with hedging and trading counterparties would require additional cash margin or collateral. The amount of potential margin fluctuates depending on trading volumes and market prices and at December 31, 2002 was estimated to be approximately $82 million.

If the Corporation's credit rating was reduced below investment grade, the Corporation may be required to provide additional security under a lease with remaining payments of $50 million and to comply with more stringent financial covenants contained in debt instruments assumed in the Triton acquisition, unless it elected to defease these obligations. The Corporation would have been in compliance with such covenants as of December 31, 2002. In addition, the amount of cash margin or collateral required under contracts with hedging and trading counterparties at December 31, 2002 would increase by $42 million to $124 million.

The Corporation guarantees the payment of up to 50% of the value of HOVENSA's crude oil purchases from suppliers other than PDVSA. At December 31, 2002, this amount was $280 million. This amount fluctuates based on the volume of crude oil purchased and the related crude oil prices. The year-end amount guaranteed is not representative of the normal contingent obligation because reduced crude oil shipments from Venezuela in December caused HOVENSA to purchase additional crude oil from other parties. Generally, this contingent obligation is approximately $100 million.

In addition, the Corporation has agreed to provide funding, in proportion to its 50% interest, to the extent HOVENSA does not have funds to meet its senior debt obligations due prior to the completion of coker construction, as defined. At December 31, 2002, the Corporation's pro rata share of HOVENSA's senior debt was $221 million, after deducting HOVENSA funds available for debt service. After completion of the coker construction project, this pro-rata share becomes $40 million until completion of construction required to meet final low sulfur fuel regulations, after which the amount reduces to $15 million.

The Corporation has a contingent purchase obligation to acquire the remaining 50% interest in a retail marketing and gasoline station joint venture for $90 million.

At December 31, the Corporation is contingently liable under letters of credit and under guarantees of the debt of other entities directly related to its business, as follows:

	Total
	(Millions of dollars)
Letters of credit	$ 89
Guarantees	269*
	$358

* Includes $221 million HOVENSA guarantee discussed above.

The Corporation conducts exploration and production activities in many foreign countries, including the United Kingdom, Norway, Denmark, Gabon, Indonesia, Thailand, Azerbaijan, Algeria, Malaysia, Colombia and Equatorial Guinea. Therefore, the Corporation is subject to the risks associated with foreign operations. These exposures include political risk (including tax law changes) and currency risk. The effects of these changes are accounted for when they occur and generally have not been material to the Corporation's liquidity or financial position.

HOVENSA L.L.C., owned 50% by the Corporation and 50% by Petroleos de Venezuela, S.A. (PDVSA), owns and operates a refinery in the Virgin Islands. Although there have been political disruptions in Venezuela which have reduced the availability of Venezuelan crude oil used in refining operations, the Corporation does not anticipate any material adverse effect on its financial position. The Corporation also has a note receivable of $395 million at December 31, 2002 from a subsidiary of PDVSA. The Corporation has collected the principal and interest payment due in February 2003 on the PDVSA note and anticipates collection of the remaining balance.

Discontinued Operations: In the first half of 2003, the Corporation took initiatives to reshape its portfolio of producing assets to reduce future costs, lengthen its reserve to production ratio, and provide capital for investment in new fields and funds to reduce debt. The Corporation exchanged producing properties in Colombia for an increased interest in a non-producing property under development in the joint development area of Malaysia and Thailand. The Corporation's Colombia properties (acquired in 2001 as part of the Triton acquisition), plus $10 million in cash, were exchanged for an additional 25% interest in natural gas reserves in the joint development area of Malaysia and Thailand (JDA). The JDA production facilities are complete, but production will not commence until the construction of a natural gas pipeline and gas plant is completed by the purchasers of the gas. It is anticipated that production will begin in 2005. The Corporation also sold certain producing properties in the Gulf of Mexico Shelf, the Jabung Field in Indonesia and several small United Kingdom fields.

The aggregate proceeds from these sales were $445 million. The net production from fields sold or exchanged at the time of disposition was approximately 45,000 barrels of oil equivalent per day.

The asset sales accelerated cash flows into 2003 that would have been received over the productive lives of the assets. The proceeds from asset sales, as well as operating cash flow, will provide capital for the development of new fields, as well as funds to repay debt. The Corporation believes the overall impact of its program of asset sales and exchanges of properties has not reduced its liquidity in the short-term or over the next five years.

Based on current estimates of production, capital expenditures, oil and gas prices and other variables, the Corporation anticipates it will fund its future operations, including capital expenditures and required debt repayment, with cash flow from operations, and, when necessary, available borrowing capacity under its presently undrawn committed revolving credit agreement totaling $1.5 billion. This agreement expires in 2006 and the Corporation expects it will be able to arrange a new committed facility at that time, if required.

Capital Expenditures

The following table summarizes the Corporation's capital expenditures in 2002, 2001 and 2000:

	2002	2001	2000
		(Millions of dollars)	
Exploration and production			
Exploration	$ 239	$ 171	$167
Production and development	1,095	1,250	536
Acquisitions	70	3,640	80
	1,404	5,061	783
Refining and marketing			
Operations	83	110	109
Acquisitions	47	50	46
	130	160	155
Total	$1,534	$5,221	$938

The amounts shown for acquisitions in 2002 principally represent final installment payments on prior year acquisitions. Capital expenditures in 2001 include $2,720 million for the Triton acquisition, excluding the assumption of debt. In addition, the Corporation purchased crude oil and natural gas reserves in the Gulf of Mexico and onshore Louisiana for $920 million. Capital expenditures above do not include an investment of $86 million in 2001 for a 50% interest in a retail marketing and gasoline station joint venture in the southeastern United States.

During 2000, the Corporation acquired from the Algerian National Oil Company a 49% interest in three producing Algerian oil fields. At December 31, 2002, the Corporation is committed to additional expenditures for the redevelopment of these fields of approximately $340 million for new wells, workovers of existing wells and water injection and gas compression facilities. A significant portion of the future expenditures will be funded by the cash flows from these fields.

During 2000, the Corporation acquired the remaining outstanding stock of the Meadville Corporation for $168 million in cash, deferred payments and preferred stock.

Capital expenditures in 2003 are expected to be approximately $1,475 million. It is anticipated that these expenditures will be financed by internally generated funds.

Market Risk Disclosure

In the normal course of its business, the Corporation is exposed to commodity risks related to changes in the price of crude oil, natural gas, refined products and electricity, as well as to changes in interest rates and foreign currency values. In the disclosures which follow, these operations are referred to as non-trading activities. The Corporation also has trading operations, principally through a 50% voting interest in a trading partnership. These activities are also exposed to commodity risks principally related to the prices of crude oil, natural gas and refined products. The following describes how these risks are controlled and managed.

Controls: The Corporation maintains a control environment under the direction of its chief risk officer and through its corporate risk policy, which the Corporation's senior management has approved. Controls include volumetric, term and value-at-risk limits. In addition, the chief risk officer must approve the use of new instruments or commodities. Risk limits are monitored daily and exceptions are reported to business units and to senior management. The Corporation's risk management department also performs independent verifications of sources of fair values and validations of valuation models. The Corporation's treasury department administers foreign exchange rate and interest rate hedging programs. These controls apply to all of the Corporation's non-trading and trading activities, including the consolidated trading partnership.

Instruments: The Corporation uses forward commodity contracts, foreign exchange forward contracts, futures, swaps and options in the Corporation's non-trading and trading activities. These contracts are widely traded instruments with standardized terms. The following describes these instruments:

- *Forward Commodity Contracts:* The forward purchase and sale of commodities is performed as part of the Corporation's normal activities. At title date, the notional value of the contract is exchanged for physical delivery of the commodity. Forward contracts that are designated as normal purchase and sale contracts under FAS No. 133 are excluded from the quantitative market risk disclosures.

- *Forward Foreign Exchange Contracts:* Forward contracts include forward purchase contracts for both the British pound sterling and the Danish kroner. These foreign currency contracts commit the Corporation to purchase a fixed amount of pound sterling and kroner at a predetermined exchange rate on a certain date.

- *Futures:* The Corporation uses exchange based futures contracts on a number of different underlying energy commodities. These contracts are settled daily with the relevant exchange and are subject to exchange position limits.

- *Swaps:* Swap contracts with third parties on commodities typically have periodic settlement dates over the life of the contract.

- *Options:* Options on various underlying energy commodities include exchange traded and third party contracts and have various exercise periods. As a writer of options, the Corporation receives a premium at the outset and bears the risk of unfavorable changes in the price of the commodity underlying the option. As a purchaser of options, the Corporation pays a premium at the outset and has the right to participate in the favorable price movements in the underlying commodities.

Quantitative Measures: The Corporation uses value-at-risk to monitor and control commodity risk within its trading and non-trading activities. The value-at-risk model uses historical simulation and the results represent the potential loss in fair value over one day at a 95% confidence level. The model captures both first and second order sensitivities for options. The potential change in fair value based on commodity price risk is presented in the non-trading and trading sections below.

For foreign exchange rate risk, the impact of a 10% change in foreign exchange rates on the value of the Corporation's portfolio of foreign currency forward contracts is presented in the non-trading section. Similarly, the impact of a 15% change in interest rates on the fair value of the Corporation's debt is also presented in the non-trading section. A 10% change in foreign exchange rates and a 15% change in interest rates over one year are considered reasonable possibilities for the purpose of providing sensitivity disclosures.

Non-Trading: The Corporation's non-trading activities include hedging of crude oil and natural gas production. Futures and swaps are used to fix the selling prices of a portion of the Corporation's future production and the related gains or losses are an integral part of the Corporation's selling prices. As of December 31, the Corporation has open hedge positions equal to 82% of its estimated 2003 worldwide crude oil production, excluding the potential effect of asset sales on future production, and 13% of its estimated 2004 worldwide crude oil production. The average price for West Texas Intermediate (WTI) related open hedge positions is $24.90 in 2003 and $24.00 in 2004. The average price for Brent related open hedge positions is $24.05 in 2003 and $23.00 in 2004. Approximately 25% of the Corporation's hedges are WTI related and the remainder are Brent. The Corporation also has hedged 45% of its 2003 United States natural gas production at an average price of $4.14 per Mcf. As market conditions change, the Corporation may adjust its hedge positions.

The Corporation also markets energy commodities including refined petroleum products, natural gas and electricity. The Corporation uses futures and swaps to fix the purchase prices of commodities to be sold under fixed-price sales contracts.

The following table summarizes the value-at-risk results of commodity related derivatives that are settled in cash and used in non-trading activities. The results may vary from time to time as hedge levels change.

	Non-Trading Activities
	(Millions of dollars)
2002	
At December 31	$ 50
Average for the year	49
High during the year	62
Low during the year	34
2001	
At December 31	35
Average for the year	33
High during the year	45
Low during the year	17

The Corporation uses foreign exchange contracts to reduce its exposure to fluctuating foreign exchange rates. To counteract these foreign exchange exposures, the Corporation enters into forward purchase contracts for both the British pound sterling and the Danish kroner. At December 31, 2002, the Corporation has $307 million of notional value foreign exchange contracts maturing in 2003 ($136 million at December 31, 2001). The change in fair value of the foreign exchange contracts from a 10% change in exchange rates is estimated to be $33 million at December 31, 2002 ($14 million at December 31, 2001).

The Corporation may use interest-rate swaps to balance exposure to interest rates. At December 31, 2002, the interest rate on substantially all of the Corporation's debt is fixed and there are no interest rate swaps. The Corporation's outstanding debt of $4,992 million has a fair value of $5,569 million at December 31, 2002 (debt of $5,665 million at December 31, 2001 had a fair value of $5,800 million). A 15% change in interest rates would change the fair value of debt at December 31, 2002 by $270 million. The impact of a 15% change in interest rates on the fair value at December 31, 2001 would have been $350 million.

Trading: The trading partnership in which the Corporation has a 50% voting interest trades energy commodities and derivatives. The accounts of the partnership are consolidated with those of the Corporation. The Corporation also takes trading positions for its own account. These strategies include proprietary position management and trading to enhance the potential return on assets. The information that follows represents 100% of the trading partnership and the Corporation's proprietary trading accounts.

In trading activities, the Corporation is exposed to changes in crude oil, natural gas and refined product prices, primarily in North America and Europe. Trading positions include futures, swaps and options. In some cases, physical purchase and sale contracts are used as trading instruments and are included in the trading results.

Derivative trading transactions are marked-to-market and are reflected in income currently. Total realized gains for the year amounted to $6 million. The following table provides an assessment of the factors affecting the changes in fair value of trading activities in 2002 and represents 100% of the trading partnership and other trading activities.

	(Millions of dollars)
Fair value of contracts outstanding at the beginning of the year	$(58)
Change in fair value of contracts outstanding at the beginning of the year and still outstanding at the end of the year	(14)
Reversal of fair value for contracts closed during the year	75
Fair value of contracts entered into during the year	33
Fair value of contracts outstanding at the end of the year	$ 36

The Corporation uses observable market values for determining the fair value of its trading instruments. The majority of valuations are based on actively quoted market values. In cases where actively quoted prices are not available, other external sources are used which incorporate information about commodity prices in actively quoted markets, quoted prices in less active markets and other market fundamental analysis. Internal estimates are based on internal models incorporating underlying market information such as commodity volatilities and correlations. The Corporation's risk management department compares valuations regularly to independent sources and models.

	Total	2003	2004
	(Millions of dollars)		
Source of fair value			
Prices actively quoted	$ 40	$ 29	$ 11
Other external sources	(14)	(14)	—
Internal estimates	10	11	(1)
Total	$ 36	$ 26	$ 10

The following table summarizes the value-at-risk results for all trading activities, including commodities. The results may change from time to time as strategies change to capture potential market rate movements.

	Trading Activities
	(Millions of dollars)
2002	
At December 31	$ 6
Average for the year	10
High during the year	12
Low during the year	6

	Trading Activities
	(Millions of dollars)
2001	
At December 31	13
Average for the year	17
High during the year	22
Low during the year	12

The following table summarizes the fair values of net receivables, including option premiums, relating to the Corporation's trading activities and the credit rating of counterparties at December 31:

	2002	2001
	(Millions of dollars)	
Investment grade determined by outside sources	$309	$260
Investment grade determined internally*	70	110
Less than investment grade	61	24
Not determined	2	4
	$442	$398

* Based on information provided by counterparties and other available sources.

Critical Accounting Policies

Accounting policies affect the recognition of assets and liabilities on the Corporation's balance sheet and revenues and expenses on the income statement. The accounting methods used can affect net income, stockholders' equity and various financial statement ratios. However, the Corporation's accounting policies generally do not change cash flows or liquidity.

The Corporation uses the successful efforts method of accounting for oil and gas producing activities. Costs to acquire or lease unproved and proved oil and gas properties are capitalized. Costs incurred in connection with the drilling and equipping of successful exploratory wells are also capitalized. If proved reserves are not found, these costs are charged to expense. Other exploration costs, including seismic, are charged to expense as incurred. Development costs, which include the costs of drilling and equipping development wells, are capitalized. Depreciation, depletion and amortization of capitalized costs of proved oil and gas properties are computed on the unit-of-production method on a field basis.

The determination of proved reserves is a significant element in arriving at the results of operations of exploration and production activities. The estimates of proved reserves can impact well capitalizations, undeveloped lease impairments and the depreciation rates of proved properties, wells and equipment. Reduction in reserve estimates may result in the need for impairments of proved properties and related assets.

The Corporation has hedged most of its 2003 crude oil and natural gas production and a portion of its 2004 production. The hedging contracts correlate to the selling prices of crude oil or natural gas and are designated as hedges. Therefore, gains or losses on these instruments are recorded in income in the period in which the production is sold. At December 31, 2002, the Corporation has $91 million of deferred hedging losses after income taxes included in other comprehensive income.

As explained below there are significant differences in the way long-lived assets and goodwill are evaluated and measured for impairment testing. The Corporation reviews long-lived assets, including oil and gas fields, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. Long-lived assets are tested at the lowest level for which cash flows are identifiable and are largely independent of the cash flows of other assets and liabilities. If the carrying amounts of the long-lived assets are not expected to be recovered by undiscounted future net cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is based on the estimated fair value of the assets determined by discounting anticipated future net cash flows.

In the case of oil and gas fields, the present value of future net cash flows is based on management's best estimate of future prices, which is determined with reference to recent historical prices and published forward prices, applied to projected production volumes of individual fields and discounted at a rate commensurate with the risks involved. The projected production volumes represent reserves, including probable reserves, expected to be produced based on a stipulated amount of capital expenditures. The production volumes, prices and timing of production are consistent with internal projections and other externally reported information. Oil and gas prices used for determining asset impairments will generally differ from those used in the standardized measure of discounted future net cash flows, since the standardized measure requires the use of actual prices on the last day of the year.

The Corporation's impairment tests of long-lived exploration and production producing assets are based on its best estimates of future production volumes (including recovery factors), selling prices, operating and capital costs and the timing of future production, which are updated each time an impairment test is performed. In 2002, the Corporation recorded significant impairments of the Ceiba field and LLOG properties that were required primarily because of reduced estimates of oil and gas production volumes and, in the case of Ceiba, anticipated additional development costs. The impairment charges did not result from changes in the other factors. The change in timing of production on the Ceiba field did not significantly affect the undiscounted future cash flows, but did reduce the fair value of the field determined by discounted cash flows. The Corporation could have additional impairments if the projected production volumes on oil and gas fields were reduced. Significant extended declines in crude oil and natural gas selling prices could also result in asset impairments.

The Corporation has recorded $977 million of goodwill in connection with the purchase of Triton. Factors contributing to the recognition of goodwill included the strategic value of expanding global operations to access new growth areas outside of the United States and the North Sea, obtaining critical mass in Africa and Southeast Asia, and synergies, including cost savings, improved processes and portfolio high grading opportunities. In accordance with FAS No. 142, goodwill is no longer amortized but must be tested for impairment annually. FAS No. 142 requires that goodwill be tested for impairment at a reporting unit level. The reporting unit or units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed. A reporting unit is an operating segment or a component which is one level below an operating segment. A component is a reporting unit if the component constitutes a business for which discrete financial information is available and segment management regularly reviews the operating results of that component. However, two or more components of an operating segment shall be aggregated and deemed a single reporting unit if the components have similar economic characteristics. An operating segment shall be deemed to be a reporting unit if all of its components are economically similar.

Within the Corporation's exploration and production operating segment there are currently two components: (1) Americas and West Africa and (2) Europe, North Africa and Asia. Each component has a manager who reports to the segment manager. The Corporation has determined the components have similar economic characteristics and, therefore, aggregates the components into a single reporting unit — the exploration and production operating segment. As a result, goodwill has been assigned to the exploration and production operating segment. If the Corporation reorganized its exploration and production business such that there was more than one operating segment, or its components were no longer economically similar, goodwill would be assigned to two or more reporting units. The goodwill would be allocated to any new reporting units using a relative fair value approach in accordance with FAS No. 142. Goodwill impairment testing for lower level reporting units could result in the recognition of an impairment that would not otherwise be recognized at the current higher level of aggregation.

The Corporation expects that the benefits of goodwill will be recovered through the operation of the exploration and production segment as a whole and it evaluated the following characteristics in determining that the components are economically similar:

- The Corporation operates its exploration and production segment as a single, global business.
- Each component produces oil and gas.
- The exploration and production processes are similar in each component.
- The methods used by each component to market and distribute oil and gas are similar.
- Customers of each component are similar.
- The components share resources and are supported by a worldwide exploration team and a shared services organization.

The Corporation's fair value estimate of the exploration and production segment is the sum of: (1) the discounted anticipated cash flows of producing assets and known developments, (2) the expected risked present value of exploration assets, and (3) an estimated market premium to reflect the market price an acquirer would pay for potential synergies including cost savings, access to new business opportunities, enterprise control, improved processes and increased market share. The Corporation also considers the relative market valuation of similar exploration and production companies.

The determination of the fair value of the exploration and production operating segment depends on judgments about oil and gas reserves, future prices, timing of future net cash flows and market premiums. The effect of synergies is embedded in the value of producing assets, known developments and exploration assets. Significant extended declines in crude oil and natural gas prices, reduced reserve estimates or failure to realize synergies could lead to a decrease in the fair value of the exploration and production operating segment that could result in an impairment of goodwill. In addition, changes in management structure or sales or dispositions of a portion of the exploration and production segment may result in goodwill impairment.

As explained above, there are significant differences in the way long-lived assets and goodwill are evaluated and measured for impairment testing. Consequently, there may be impairments of individual assets which would not cause an impairment of the $977 million of goodwill assigned to the exploration and production segment. In 2002, the Corporation recognized asset impairments because reduced estimates of oil and gas production volumes caused the expected undiscounted cash flows of the assets to be lower than the asset carrying amounts. No impairment of goodwill exists because the fair value of the overall exploration and production operating segment continues to exceed its recorded book value.

The Corporation has two operating segments, exploration and production, and refining and marketing. Management has determined that these are its operating segments because, in accordance with FAS No. 131, these are the segments of the Corporation (i) that engage in business activities from which revenues are earned and expenses are incurred, (ii) whose operating results are regularly reviewed by the Corporation's chief operating decision maker to make decisions about resources to be allocated to the segment and assess its performance and (iii) for which discrete financial information is available. Mr. John B. Hess, Chairman of the Board and Chief Executive Officer of the Corporation, is the chief operating decision maker ("CODM") as defined in FAS No. 131, because he is responsible for performing the functions within the Corporation of allocating resources to and assessing the performance of the Corporation's operating segments. Mr. Hess uses only the operating results of each segment as a whole to make decisions about resources to be allocated to each segment and to assess the segment performance. The CODM manages each segment globally and does not regularly review the operating results of any component (e.g., geographic area) or asset within each segment or any information by geographical location, oil and gas property or project, subsidiary or division, to make decisions about resources to be allocated or to assess performance. While the CODM does review and approve initial corporate funding for a new project using information about the project, he does not review subsequent operating results by project after the initial funding. Each operating segment has one manager. The segment managers are responsible for allocating resources within the segments, reviewing financial results of components within the segments, and assessing the performance of the components. The CODM evaluates the performance of the segment managers based on performance metrics related to each manager's operating segment as a whole. The Board of Directors of the Corporation does not receive more detailed information than that used by the CODM to operate and manage the Corporation.

The oil and gas industry is currently discussing the appropriate balance sheet classification of oil and gas mineral rights held by lease or contract. The Corporation classifies these assets as property, plant and equipment in accordance with its interpretation of FAS No. 19 and common industry practice. There is also a view that these mineral rights are intangible assets as defined in FAS No. 141, *Business Combinations*, and, therefore, should be classified separately on the balance sheet as intangible assets. If the accounting for mineral rights held by lease or contract is ultimately changed, the Corporation believes that any such reclassification of mineral rights could amount to approximately $2.2 billion at December 31, 2002 and $3.3 billion at December 31, 2001, if the Corporation is required to include the purchase price allocated to hydrocarbon reserves obtained in acquisitions of oil and gas properties. The determination of this amount is based on the Corporation's current understanding of this evolving issue and how the provisions of FAS No. 141 might be applied to oil and gas mineral rights. This potential balance sheet reclassification would not affect results of operations or cash flows.

Environment, Health and Safety

The Corporation is committed to continuous improvement of its environmental, health and safety performance. This includes compliance with all laws and regulations covering environment, health and safety wherever it operates and the establishment of internal standards that may go beyond local requirements. The Corporation is committed to promoting environment, health, safety and social responsibility policies and management systems that protect the Corporation's workforce, customers and local communities. In 2002, the Corporation established new environment, health and safety and social responsibility policies. Senior management has overall responsibility for setting environment, health and safety direction and providing oversight.

To ensure that the Corporation meets its goals and the requirements of regulatory authorities, the Corporation has programs for compliance evaluation, facility auditing and employee training. Environment and safety management systems, based on international standards, are used throughout the Corporation to ensure consistency and adherence to policy objectives. Improved performance in environment, health and safety raises the Corporation's operating costs and requires increased capital expenditures while reducing potential risks to corporate assets, reputation and ability to operate.

The Port Reading refining facility and the HOVENSA refinery manufacture conventional and reformulated gasolines that are cleaner burning than required under U.S. regulations currently in effect. In addition, the benzene and sulfur content in the Corporation's gasoline is approximately one-half of the national average (excluding California), resulting in significantly lower toxic emissions than the industry average.

The regulation of motor fuels in the United States and elsewhere continues to be an area of considerable change and will require large capital expenditures in future years. In December 1999, the United States Environmental Protection Agency ("EPA") adopted rules that phase in limitations on the sulfur content of gasoline beginning in 2004. In December 2000, the EPA adopted regulations to reduce substantially the allowable sulfur content of diesel fuel by 2006.

The Corporation and HOVENSA continue to review options to determine the most cost effective compliance strategies for these fuel regulations. The costs to comply will depend on a variety of factors, including the availability of suitable technology and contractors and the credit trading programs. Capital expenditures necessary to comply with the low-sulfur gasoline requirements at Port Reading are expected to be approximately $70 million over the next four years. Capital expenditures to comply with low-sulfur gasoline and diesel fuel requirements at HOVENSA are presently expected to be $450 million over the next four years. HOVENSA expects to finance these capital expenditures through cash flow and, if necessary, future borrowings.

Legislation to restrict or ban the use of MTBE, a gasoline oxygenate, and to require the use of ‘renewable’ fuels was considered by the United States Congress in 2002 and will likely be reconsidered. The Corporation and HOVENSA both manufacture and use MTBE primarily to meet the federal requirement for oxygen in reformulated gasoline, and do not presently use ethanol. Several states in the Corporation’s market area have enacted bans on MTBE use, including Connecticut (effective October 2003) and New York (effective January 2004), and other states are considering them. If Congress bans MTBE or if state bans take effect, or if an obligation to use ethanol or other renewable fuels is imposed, the effect on the Corporation and HOVENSA could be significant. Whether the effect is significant will depend on several factors, including the extent and timing of any such bans or obligations, requirements for maintenance of certain air emission reductions if MTBE is banned, the cost and availability of alternative oxygenates or credits and whether the minimum oxygen content standard for reformulated gasoline remains in effect. The Corporation is reviewing its options to market and produce reformulated gasolines if MTBE bans take effect.

EPA issued several draft and final rules in 2002 to implement requirements of the Clean Air Act to reduce hazardous air pollutant emissions from certain sources, including certain refinery sources. Some capital expenditures could be required by the Corporation or HOVENSA to comply with these regulations, but further review of these rules is continuing to determine their impact.

The Corporation expects continuing expenditures for environmental assessment and remediation related primarily to existing conditions. Sites where corrective action may be necessary include gasoline stations, terminals, onshore exploration and production facilities, refineries (including solid waste management units under permits issued pursuant to the Resource Conservation and Recovery Act) and, although not significant, “Superfund” sites where the Corporation has been named a potentially responsible party. The Corporation expects that existing reserves for environmental liabilities will adequately cover costs to assess and remediate known sites.

The Corporation spent $9 million in 2002, $8 million in 2001 and $7 million in 2000 for remediation. Capital expenditures for facilities, primarily to comply with federal, state and local environmental standards, were $5 million in 2002, $6 million in 2001 and $5 million in 2000.

Forward Looking Information

Certain sections of Management’s Discussion and Analysis of Results of Operations and Financial Condition, including references to the Corporation’s future results of operations and financial position, liquidity and capital resources, capital expenditures, oil and gas production, tax rates, debt repayment, hedging, derivative and environmental disclosures, represent forward looking information. Forward looking disclosures are based on the Corporation’s current understanding and assessment of these activities and reasonable assumptions about the future. Actual results may differ from these disclosures because of changes in market conditions, government actions and other factors.

Dividends

Cash dividends on common stock totaled $1.20 per share ($.30 per quarter) during 2002 and 2001.

Stock Market Information

The common stock of Amerada Hess Corporation is traded principally on the New York Stock Exchange (ticker symbol: AHC). High and low sales prices in 2002 and 2001 were as follows:

Quarter Ended	2002 High	2002 Low	2001 High	2001 Low
March 31	$80.15	$57.60	$79.45	$66.25
June 30	84.70	74.61	90.40	73.40
September 30	83.00	61.36	82.39	59.07
December 31	71.48	49.40	68.96	53.75

Quarterly Financial Data

Quarterly results of operations for the years ended December 31, 2002 and 2001 follow:

	Sales and Other Operating Revenues	Gross Profit(a)	Net Income (Loss)	Net Income (Loss) Per Share
	(Millions of dollars, except per share data)			
2002				
First	$2,926	$368	$ 140(b)	$ 1.58
Second	2,694	385	149(c)	1.66
Third	2,724	419	(136)(d)	(1.54)
Fourth	3,207	431	(371)(e)	(4.20)
2001				
First	4,139	673	337	3.79
Second	3,406	593	357	3.98
Third	2,854	372	166	1.86
Fourth	2,653	324	54(f)	.61

(a) Gross profit represents sales and other operating revenues, less cost of products sold, production expenses, marketing expenses, other operating expenses and depreciation, depletion and amortization.

(b) Reflects a net gain from asset sales of $42 million ($62 million before income taxes).

(c) Includes charges of $14 million ($22 million before income taxes) for the reduction in carrying value of intangible assets related to energy marketing activities and $8 million ($13 million before income taxes) for a severance accrual.

(d) Reflects a net charge of $207 million ($318 million before income taxes) for impairment of U.S. producing properties and exploration acreage. Also includes a net gain from asset sales of $45 million ($68 million before income taxes) and a deferred tax charge of $43 million for an increase in the United Kingdom income tax rate.

(e) Includes a net charge of $530 million ($706 million before income taxes) for impairment of the Ceiba field. Also includes a net gain from an asset sale of $13 million ($13 million before income taxes).

(f) Includes a net charge of $19 million ($29 million before income taxes) related to the Enron bankruptcy and $12 million ($18 million before income taxes) for a severance accrual.

The results of operations for the periods reported herein should not be considered as indicative of future operating results.

Amerada Hess Corporation and Consolidated Subsidiaries

CONSOLIDATED BALANCE SHEET

	At December 31	
	2002	**2001**
	(Millions of dollars)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 197	$ 37
Accounts receivable		
Trade	1,785	2,841
Other	187	121
Inventories	492	550
Other current assets	95	397
Total current assets	2,756	3,946
Investments and Advances		
HOVENSA L.L.C.	842	889
Other	780	747
Total investments and advances	1,622	1,636
Property, Plant and Equipment		
Exploration and production	14,699	15,194
Refining and marketing	1,450	1,433
Total — at cost	16,149	16,627
Less reserves for depreciation, depletion, amortization and lease impairment	9,117	8,462
Property, plant and equipment — net	7,032	8,165
Notes Receivable	363	395
Goodwill	977	982
Deferred Income Taxes and Other Assets	512	245
Total Assets	$13,262	$15,369

The consolidated financial statements reflect the successful efforts method of accounting for oil and gas exploration and producing activities.

See accompanying notes to consolidated financial statements.

Amerada Hess Corporation and Consolidated Subsidiaries

CONSOLIDATED BALANCE SHEET

	At December 31	
	2002	**2001**
	(Millions of dollars, thousands of shares)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable — trade	$ 1,401	$ 1,807
Accrued liabilities	830	1,115
Taxes payable	306	414
Notes payable	2	106
Current maturities of long-term debt	14	276
Total current liabilities	2,553	3,718
Long-Term Debt	4,976	5,283
Deferred Liabilities and Credits		
Deferred income taxes	1,044	1,111
Other	440	350
Total deferred liabilities and credits	1,484	1,461
Stockholders' Equity		
Preferred stock, par value $1.00, 20,000 shares authorized		
3% cumulative convertible series		
Authorized — 330 shares		
Issued — 327 shares in 2002 and 2001 ($16 million liquidation preference)	—	—
Common stock, par value $1.00		
Authorized — 200,000 shares		
Issued — 89,193 shares in 2002; 88,757 shares in 2001	89	89
Capital in excess of par value	932	903
Retained earnings	3,482	3,807
Accumulated other comprehensive income (loss)	(254)	108
Total stockholders' equity	4,249	4,907
Total Liabilities and Stockholders' Equity	$13,262	$15,369

See accompanying notes to consolidated financial statements.

Amerada Hess Corporation and Consolidated Subsidiaries

STATEMENT OF CONSOLIDATED INCOME

	For the Years Ended December 31		
	2002	**2001**	**2000**
	(Millions of dollars, except per share data)		
Revenues and Non-operating Income			
Sales (excluding excise taxes) and other operating revenues	$11,551	$13,052	$11,747
Non-operating income (expense)			
Gain on asset sales	143	—	—
Equity in income (loss) of HOVENSA L.L.C.	(47)	58	121
Other	85	150	165
Total revenues and non-operating income	11,732	13,260	12,033
Costs and Expenses			
Cost of products sold	7,226	8,739	7,885
Production expenses	736	642	522
Marketing expenses	703	663	542
Exploration expenses, including dry holes and lease impairment	316	347	282
Other operating expenses	165	213	234
General and administrative expenses	253	311	222
Interest expense	256	194	162
Depreciation, depletion and amortization	1,118	833	676
Asset impairments	1,024	—	—
Total costs and expenses	11,797	11,942	10,525
Income (loss) from continuing operations before income taxes	(65)	1,318	1,508
Provision for income taxes	180	502	591
Income (loss) from continuing operations	(245)	816	917
Discontinued operations	27	98	106
Net Income (Loss)	$ (218)	$ 914	$ 1,023
Basic Earnings (Loss) Per Share			
Continuing operations	$ (2.78)	$ 9.26	$ 10.29
Net income (loss)	(2.48)	10.38	11.48
Diluted Earnings (Loss) Per Share			
Continuing operations	$ (2.78)	$ 9.15	$ 10.20
Net income (loss)	(2.48)	10.25	11.38

See accompanying notes to consolidated financial statements.

Amerada Hess Corporation and Consolidated Subsidiaries

STATEMENT OF CONSOLIDATED RETAINED EARNINGS

	For the Years Ended December 31		
	2002	2001	2000
	(Millions of dollars, except per share data)		
Balance at Beginning of Year	$3,807	$3,069	$2,287
Net income (loss)	(218)	914	1,023
Dividends declared — common stock ($1.20 per share in 2002 and 2001; $.60 per share in 2000)	(107)	(107)	(54)
Common stock acquired and retired	—	(69)	(187)
Balance at End of Year	$3,482	$3,807	$3,069

See accompanying notes to consolidated financial statements.

Amerada Hess Corporation and Consolidated Subsidiaries

STATEMENT OF CONSOLIDATED CASH FLOWS

	For the Years Ended December 31		
	2002	2001	2000
	(Millions of dollars)		
Cash Flows From Operating Activities			
Net income (loss)	$ (218)	$ 914	$ 1,023
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	1,118	833	676
Asset impairments	1,024	—	—
Exploratory dry hole costs	157	185	128
Lease impairment	41	38	32
Pre-tax gain on asset sales	(117)	—	—
Provision (benefit) for deferred income taxes	(258)	64	164
Undistributed earnings of affiliates	47	(52)	(119)
Non-cash effect of discontinued operations	280	153	44
Changes in other operating assets and liabilities			
(Increase) decrease in accounts receivable	(104)	650	(1,792)
(Increase) decrease in inventories	51	(131)	(23)
Increase (decrease) in accounts payable and accrued liabilities	(217)	(553)	1,617
Increase (decrease) in taxes payable	50	(185)	272
Changes in prepaid expenses and other	111	44	(227)
Net cash provided by operating activities	1,965	1,960	1,795
Cash Flows From Investing Activities			
Capital expenditures			
Exploration and production	(1,404)	(2,341)	(783)
Refining and marketing	(130)	(160)	(155)
Total capital expenditures	(1,534)	(2,501)	(938)
Acquisition of Triton Energy Limited, net of cash acquired	—	(2,720)	—
Payment received on note	48	48	48
Investment in affiliates	—	(86)	(38)
Proceeds from asset sales and other	390	54	26
Net cash used in investing activities	(1,096)	(5,205)	(902)
Cash Flows From Financing Activities			
Debt with maturities of 90 days or less — increase (decrease)	(581)	564	(131)
Debt with maturities of greater than 90 days			
Borrowings	637	2,595	20
Repayments	(686)	(54)	(296)
Cash dividends paid	(107)	(94)	(54)
Common stock and warrants acquired	—	(100)	(220)
Stock options exercised	28	59	59
Net cash provided by (used in) financing activities	(709)	2,970	(622)
Net Increase (Decrease) in Cash and Cash Equivalents	160	(275)	271
Cash and Cash Equivalents at Beginning of Year	37	312	41
Cash and Cash Equivalents at End of Year	$ 197	$ 37	$ 312

See accompanying notes to consolidated financial statements.

Amerada Hess Corporation and Consolidated Subsidiaries

STATEMENT OF CONSOLIDATED CHANGES IN PREFERRED STOCK, COMMON STOCK AND CAPITAL IN EXCESS OF PAR VALUE

	Preferred Stock		Common Stock		Capital in Excess of Par Value
	Number of Shares	Amount	Number of Shares	Amount	
	(Million of dollars; thousands of shares)				
Balance at January 1, 2000	—	$ —	90,676	$ 91	$782
Distributions to trustee of nonvested common stock awards (net)	—	—	461	—	28
Common stock acquired and retired	—	—	(3,475)	(3)	(31)
Employee stock options exercised	—	—	1,082	1	69
Issuance of preferred stock	327	—	—	—	16
Balance at December 31, 2000	327	—	88,744	89	864
Distributions to trustee of nonvested common stock awards (net)	—	—	38	—	1
Common stock acquired and retired	—	—	(1,078)	(1)	(11)
Employee stock options exercised	—	—	1,053	1	69
Warrants purchased	—	—	—	—	(20)
Balance at December 31, 2001	327	—	88,757	89	903
Cancellations of nonvested common stock awards (net)	—	—	(55)	—	(3)
Employee stock options exercised	—	—	491	—	32
Balance at December 31, 2002	327	$ —	89,193	$ 89	$932

STATEMENT OF CONSOLIDATED COMPREHENSIVE INCOME

	For the Years Ended December 31		
	2002	2001	2000
	(Millions of dollars)		
Components of Comprehensive Income (Loss)			
Net income (loss)	$(218)	$ 914	$1,023
Change in foreign currency translation adjustment	34	(2)	(17)
Additional minimum pension liability, after tax	(71)	—	—
Unrealized gains (losses) on oil and gas cash flow hedges, after tax			
FAS 133 transition adjustment	—	100	—
Reclassification of deferred hedging gains to income	(56)	(74)	—
Net change in fair value of cash flow hedges	(269)	223	—
Comprehensive Income (Loss)	$(580)	$1,161	$1,006

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Nature of Business: Amerada Hess Corporation and subsidiaries (the "Corporation") engage in the exploration for and the production, purchase, transportation and sale of crude oil and natural gas. These activities are conducted primarily in the United States, United Kingdom, Norway, Denmark and Equatorial Guinea. The Corporation also has oil and gas activities in Algeria, Azerbaijan, Colombia, Gabon, Indonesia, Malaysia, Thailand and other countries. In addition, the Corporation manufactures, purchases, transports, trades and markets refined petroleum and other energy products. The Corporation owns 50% of HOVENSA L.L.C., a refinery joint venture in the United States Virgin Islands. An additional refining facility, terminals and retail gasoline stations are located on the East Coast of the United States.

In preparing financial statements, management makes estimates and assumptions that affect the reported amounts of assets and liabilities in the balance sheet and revenues and expenses in the income statement. Actual results could differ from those estimates. Among the estimates made by management are: oil and gas reserves, asset valuations and depreciable lives, pension liabilities, environmental obligations, dismantlement costs and income taxes.

Principles of Consolidation: The consolidated financial statements include the accounts of Amerada Hess Corporation and entities in which the Corporation owns more than 50% voting interest or entities that the Corporation controls. The Corporation's undivided interests in unincorporated oil and gas exploration and production ventures are proportionately consolidated.

Investments in affiliated companies, 20% to 50% owned, including HOVENSA but excluding a trading partnership, are stated at cost of acquisition plus the Corporation's equity in undistributed net income since acquisition. The change in the equity in net income of these companies is included in non-operating income in the income statement. The Corporation consolidates the trading partnership in which it owns a 50% voting interest and over which it exercises control.

Intercompany transactions and accounts are eliminated in consolidation.

Revenue Recognition: The Corporation recognizes revenues from the sale of crude oil, natural gas, petroleum products and other merchandise when title passes to the customer.

The Corporation recognizes revenues from the production of natural gas properties in which it has an interest based on sales to customers. Differences between natural gas volumes sold and the Corporation's share of natural gas production are not material.

Cash and Cash Equivalents: Cash equivalents consist of highly liquid investments, which are readily convertible into cash and have maturities of three months or less when acquired.

Inventories: Crude oil and refined product inventories are valued at the lower of average cost or market. For inventories valued at cost, the Corporation uses principally the last-in, first-out (LIFO) inventory method.

Inventories of materials and supplies are valued at the lower of cost or market.

Exploration and Development Costs: Oil and gas exploration and production activities are accounted for using the successful efforts method. Costs of acquiring unproved and proved oil and gas leasehold acreage, including lease bonuses, brokers' fees and other related costs, are capitalized.

Annual lease rentals and exploration expenses, including geological and geophysical expenses and exploratory dry hole costs, are charged against income as incurred.

Costs of drilling and equipping productive wells, including development dry holes, and related production facilities are capitalized.

The costs of exploratory wells that find oil and gas reserves are capitalized pending determination of whether proved reserves have been found. In an area requiring a major capital expenditure before production can begin, an exploration well is carried as an asset if sufficient reserves are discovered to justify its completion as a production well, and additional exploration drilling is underway or firmly planned. The Corporation does not capitalize the cost of other exploratory wells for more than one year unless proved reserves are found.

Depreciation, Depletion and Amortization: The Corporation calculates depletion expense for acquisition costs of proved properties using the units of production method over proved oil and gas reserves. Depreciation and depletion expense for oil and gas production equipment and wells is calculated using the units of production method over proved developed oil and gas reserves. Depreciation of all other plant and equipment is determined on the straight-line method based on estimated useful lives.

Provisions for impairment of undeveloped oil and gas leases are based on periodic evaluations and other factors.

The estimated costs of dismantlement, restoration and abandonment, less estimated salvage values, of offshore oil and gas production platforms and pipelines are accrued using the units-of-production method and are reported as a component of depreciation expense and accumulated depreciation (see note 17).

Retirement of Property, Plant and Equipment: Costs of property, plant and equipment retired or otherwise disposed of, less accumulated reserves, are reflected in non-operating income.

Impairment of Long-Lived Assets: The Corporation reviews long-lived assets, including oil and gas properties at a field level, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts are not expected to be recovered by undiscounted future cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is based on the estimated fair value of the assets determined by discounting anticipated future net cash flows. In the case of oil and gas fields, the net present value of future cash flows is based on management's best estimate of future prices, which is determined with reference to recent historical prices and published forward prices, applied to projected production volumes of individual fields and discounted at a rate commensurate with the risks involved. The projected production volumes represent reserves, including probable reserves, expected to be produced based on a stipulated amount of capital expenditures. The production volumes, prices and timing of production are consistent with internal projections and other externally reported information. Oil and gas prices used for determining asset impairments will generally differ from those used at year-end in the standardized measure of discounted future net cash flows.

Impairment of Equity Investees: The Corporation reviews equity method investments for impairment whenever events or changes in circumstances indicate that an other than temporary decline in value has occurred. The amount of the impairment is based on quoted market prices, where available, or other valuation techniques, including discounted cash flows.

Impairment of Goodwill: In accordance with FAS No. 142, *Goodwill and Other Intangible Assets*, goodwill cannot be amortized; however, it must be tested annually for impairment. This impairment test is calculated at the reporting unit level, which is the exploration and production segment for the Corporation's goodwill. The Corporation identifies potential impairments by comparing the fair value of the reporting unit to its book value, including goodwill. If the fair value of the reporting unit exceeds the carrying amount, goodwill is not impaired. If the carrying value exceeds the fair value, the Corporation calculates the possible impairment loss by comparing the implied fair value of goodwill with the carrying amount. If the implied goodwill is less than the carrying amount, a write-down is recorded.

Maintenance and Repairs: The estimated costs of major maintenance, including turnarounds at the Port Reading refining facility, are accrued. Other expenditures for maintenance and repairs are charged against income as incurred. Renewals and improvements are treated as additions to property, plant and equipment, and items replaced are treated as retirements.

Environmental Expenditures: The Corporation capitalizes environmental expenditures that increase the life or efficiency of property or that reduce or prevent environmental contamination. The Corporation accrues for environmental expenses resulting from existing conditions related to past operations when the future costs are probable and reasonably estimable.

Employee Stock Options and Nonvested Common Stock Awards: The Corporation uses the intrinsic value method to account for employee stock options. Because the exercise prices of employee stock options equal or exceed the market price of the stock on the date of grant, the Corporation does not recognize compensation expense. The Corporation records compensation expense for non-vested common stock awards ratably over the vesting period. The following pro forma financial information presents the effect on net income and earnings per share as if the Corporation used the fair value method.

	2002	2001	2000
		(Millions of dollars, except per share data)	
Net income (loss)	$ (218)	$ 914	$1,023
Add stock-based employee compensation expense included in net income, net of taxes	5	8	4
Less total stock-based employee compensation expense determined using the fair value method, net of taxes	(19)	(22)	(21)
Pro forma net income (loss)	$ (232)	$ 900	$1,006
Net income (loss) per share as reported			
Basic	$(2.48)	$10.38	$11.48
Diluted	(2.48)	10.25	11.38
Pro forma net income (loss) per share			
Basic	$(2.63)	$10.23	$11.29
Diluted	(2.63)	10.10	11.19

Foreign Currency Translation: The U.S. dollar is the functional currency (primary currency in which business is conducted) for most foreign operations. For these operations, adjustments resulting from translating foreign currency assets and liabilities into U.S. dollars are recorded in income. For operations that use the local currency as the functional currency, adjustments resulting from translating foreign functional currency assets and liabilities into U.S. dollars are recorded in a separate component of stockholders' equity entitled accumulated other comprehensive income. Gains or losses resulting from transactions in other than the functional currency are reflected in net income.

Hedging: The Corporation uses futures, forwards, options and swaps, individually or in combination, to reduce the effects of fluctuations in crude oil, natural gas and refined product prices. The Corporation also uses derivatives in its energy marketing activities to fix the purchase and selling prices of energy products. Related hedge gains or losses are an integral part of the selling or purchase prices. Generally, these derivatives are designated as hedges of expected future cash flows or forecasted transactions (cash flow hedges), and the gains or losses are recorded in accumulated other comprehensive income. These transactions meet the requirements for hedge accounting, including correlation. The Corporation reclassifies hedging gains and losses included in accumulated other comprehensive income to earnings at the time the hedged transactions are recognized. The ineffective portion of hedges is included in current earnings. The Corporation's remaining derivatives, including foreign currency contracts, are not designated as hedges and the change in fair value is included in income currently.

Trading: Derivatives used in energy trading activities are marked to market, with net gains and losses recorded in operating revenue.

2. Items Affecting Income from Continuing Operations

2002: The Corporation recorded a pre-tax impairment charge of $706 million relating to the Ceiba field in Equatorial Guinea. The charge resulted from a reduction in probable reserves of approximately 12% of total field reserves, as well as the additional development costs of producing these reserves over a longer field life. Fair value was determined by discounting anticipated future net cash flows. Discounted cash flow was less than the book value of the field, which included allocated purchase price from the Triton acquisition. The Corporation also recorded a pre-tax impairment charge of $318 million to reduce the carrying value of oil and gas properties located primarily in the Main Pass/Breton Sound area of the Gulf of Mexico. Most of these properties were obtained in the 2001 LLOG acquisition and consisted of producing oil and gas fields with proved and probable reserves and exploration acreage. This charge principally reflects reduced reserve estimates on these fields resulting from unfavorable production performance. The fair values of producing properties were determined by using discounted cash flows. Exploration properties were evaluated by using results of drilling and production data from nearby fields and seismic data for these and other properties in the area. The pre-tax amounts of these charges were recorded in the caption asset impairments in the income statement.

During 2002, the Corporation completed the sale of six United States flag vessels for $161 million in cash and a note for $29 million. The sale resulted in a pre-tax gain of $102 million. The Corporation has agreed to support the buyer’s charter rate for these vessels for up to five years. A pre-tax gain of $50 million has been deferred as part of the sale transaction to reflect potential obligations of the support agreement. The support agreement requires that, if the actual contracted rate for the charter of a vessel is less than the stipulated charter rate in the agreement, the Corporation pay to the buyer the difference between the contracted rate and the stipulated rate. If the actual contracted rate exceeds the stipulated rate, the buyer must apply such amount to reimburse the Corporation for any payments made by the Corporation up to that date. While the Corporation’s eventual obligations under the support agreement could exceed the amount of the deferred gain, based on current charter rates the amount recorded is appropriate. During 2002, the Corporation paid $2 million relating to this support agreement.

A net pre-tax gain of $40 million was recorded during 2002 from sales of oil and gas producing properties in the United States, United Kingdom and Azerbaijan and the Corporation’s energy marketing business in the United Kingdom.

The sale of the six United States flag vessels related to the refining and marketing segment and the remaining asset sales related to exploration and production activities. The pre-tax amounts of these asset sales are recorded in non-operating income in the income statement.

The United Kingdom government enacted a 10% supplementary tax on profits from oil and gas production in 2002. As a result of this tax law change, the Corporation recorded a one-time provision for deferred taxes of $43 million to increase the deferred tax liability on its balance sheet.

In 2002, the Corporation recorded a pre-tax charge of $22 million for the write-off of intangible assets in its U.S. energy marketing business. In addition, accrued severance of $13 million was recorded for cost reduction initiatives in refining and marketing, principally in energy marketing. Approximately 165 positions were eliminated and an office was closed. The estimated annual savings from the staff reduction is $15 million before tax.

During 2002, the Corporation paid $21 million against its severance reserves, including amounts provided in 2001 for exploration and production operations. At December 31, 2002 the remaining balance in the severance reserves is $8 million.

2001: The Corporation recorded a pre-tax charge of $29 million for estimated losses due to the bankruptcy of certain subsidiaries of Enron Corporation. The charge reflected losses on less than 10% of the Corporation’s crude oil and natural gas hedges. In addition, the Corporation recorded a pre-tax charge of $18 million for severance expenses resulting from cost reduction initiatives. The cost reduction program reflected the elimination of approximately 150 positions, principally in exploration and production operations. Substantially all of the pre-tax cost of these items are reflected in general and administrative expense in the income statement.

2000: The Corporation recorded a pre-tax gain of $97 million from the termination of its proposed acquisition of another oil company. The income principally reflected foreign currency gains on pound sterling contracts which were purchased in anticipation of the acquisition. The Corporation also recorded income from a termination payment which was received from the other company, partially offset by transaction costs. The combined results of these transactions were recorded in the Corporate segment. Refining and marketing results included a pre-tax charge of $38 million for costs associated with an alternative fuel research and development venture. Both of these items are reflected in non-operating income in the income statement.

3. Discontinued Operations

In the first half of 2003, the Corporation took initiatives to reshape its portfolio of exploration and production segment assets to reduce costs, to lengthen reserve lives, to provide capital for investment and to reduce debt.

In the first quarter of 2003, the Corporation exchanged its crude oil producing properties in Colombia (acquired in 2001 as part of the Triton acquisition), plus $10 million in cash, for an additional 25% interest in natural gas reserves in the joint development area of Malaysia and Thailand. The exchange resulted in a charge to income of $51 million before income taxes, which the Corporation reported as a loss from discontinued operations in the first quarter of 2003. The loss on this exchange included a $43 million pre-tax adjustment of the book value of the Colombian assets to fair value resulting primarily from a revision in crude oil reserves. The loss also included $26 million from the recognition in earnings of the value of related hedge contracts at the time of the exchange. These items were partially offset by pre-tax earnings in Colombia prior to the exchange of $18 million.

In this exchange transaction, the Corporation acquired the 50% interest in a corporate joint venture that it did not already own. Prior to the exchange, the Corporation accounted for its 50% interest in the corporate joint venture using the equity method. Because of the exchange, the joint venture became a wholly owned subsidiary. Consequently, the Corporation will consolidate this subsidiary, which holds a 50% interest in a production sharing contract with natural gas reserves in the joint development area of Malaysia and Thailand. At the time of the exchange, the exploration and production segment included the net book value of fixed assets in Colombia of $670 million ($685 million at December 31, 2002) and a related deferred income tax liability of $142 million ($145 million at December 31, 2002).

In the second quarter of 2003, the Corporation sold producing properties in the Gulf of Mexico shelf, the Jabung Field in Indonesia and several small United Kingdom fields. The aggregate proceeds from these sales were $445 million and the pre-tax gain from disposition was $248 million. With respect to the assets sold in the second quarter of 2003, the net book value of fixed assets at the time of sale was approximately $295 million ($275 million at December 31, 2002) and the related dismantlement and deferred tax liabilities were approximately $160 million ($170 million at December 31, 2002).

Sales and other operating revenues (net of intercompany sales) from discontinued operations were $381 million in 2002, $361 million in 2001 and $246 million in 2000. Pretax profit for the same periods was $14 million, $120 million and $164 million, respectively. Income tax expense (benefit) was ($13) million, $22 million and $58 million for the same periods. The net production from fields sold or exchanged in 2003 at the time of disposition was approximately 45,000 barrels of oil equivalent per day.

4. Acquisition of Triton Energy Limited

In 2001, the Corporation acquired 100% of the outstanding ordinary shares of Triton Energy Limited, an international oil and gas exploration and production company. The Corporation’s consolidated financial statements include Triton’s results of operations from August 14, 2001. The acquisition of Triton increased the size and scope of the Corporation’s exploration and production operations, providing access to long-lived international reserves and exploration potential. The purchase price resulted in the recognition of goodwill. Factors contributing to the recognition of goodwill included the strategic value of expanding global operations to access new growth areas outside of the United States and the North Sea, obtaining critical mass in Africa and Southeast Asia, and synergies, including cost savings, improved processes and portfolio high grading opportunities.

The Corporation accounted for the acquisition as a purchase using the accounting standards established in Statements of Financial Accounting Standards No. 141, *Business Combinations*, and No. 142, *Goodwill and Other Intangible Assets*. The accounting standard requires that the goodwill arising from the purchase method of accounting not be amortized, however, it must be tested for impairment at least annually.

The estimated fair values of assets acquired and liabilities assumed at August 14, 2001 follow:

	Millions of dollars
Current assets (net of cash acquired)	$ 101
Investments and advances	447
Property, plant and equipment	2,605
Other assets	7
Goodwill	982
Total assets acquired	4,142
Current liabilities	(282)
Long-term debt, average rate 6.3%, due through 2007	(555)
Deferred liabilities and credits	(585)
Total liabilities assumed	(1,422)
Net assets acquired	$ 2,720

The goodwill is assigned to the exploration and production reporting unit and is not deductible for income tax purposes, but is taken into account in the determination of foreign tax credits. Since the acquisition, goodwill has decreased by $5 million, mainly related to changes in contingent liabilities.

The following pro forma results of operations present information as if the Triton acquisition occurred at the beginning of each year:

	2001	2000
	(Millions of dollars, except per share data)	
Pro forma revenue	$13,936	$12,620
Pro forma income	$ 914	$ 1,010
Pro forma earnings per share		
Basic	$ 10.38	$ 11.34
Diluted	$ 10.25	$ 11.24

5. Inventories

Inventories at December 31 are as follows:

	2002	2001
	(Millions of dollars)	
Crude oil and other charge stocks	$ 99	$ 108
Refined and other finished products	497	440
Less: LIFO adjustment	(261)	(111)
	335	437
Materials and supplies	157	113
Total	$ 492	$ 550

6. Refining Joint Venture

The Corporation has an investment in HOVENSA L.L.C., a 50% joint venture with Petroleos de Venezuela, S.A. (PDVSA). HOVENSA owns and operates a refinery in the Virgin Islands, previously wholly-owned by the Corporation.

The Corporation accounts for its investment in HOVENSA using the equity method. Summarized financial information for HOVENSA as of December 31, 2002, 2001 and 2000 and for the years then ended follows:

	2002	2001	2000
		(Millions of dollars)	
Summarized Balance Sheet			
At December 31			
Current assets	$ 520	$ 491	$ 523
Net fixed assets	1,895	1,846	1,595
Other assets	40	35	37
Current liabilities	(335)	(294)	(425)
Long-term debt	(467)	(365)	(131)
Deferred liabilities and credits	(45)	(23)	(22)
Partners' equity	$ 1,608	$ 1,690	$ 1,577
Summarized Income Statement			
For the years ended December 31			
Total revenues	$ 3,783	$ 4,209	$ 5,243
Costs and expenses	(3,872)	(4,089)	(4,996)
Net income (loss)*	$ (89)	$ 120	$ 247

* The Corporation's share of HOVENSA's loss was $47 million in 2002, compared with income of $58 million in 2001 and $121 million in 2000.

The Corporation has agreed to purchase 50% of HOVENSA's production of refined products at market prices, after sales by HOVENSA to unaffiliated parties. Such purchases amounted to approximately $1,280 million during 2002, $1,500 million during 2001 and $2,080 million during 2000. The Corporation sold crude oil to HOVENSA for approximately $80 million during 2002, $110 million during 2001 and $98 million during 2000. The Corporation guarantees the payment of up to 50% of the value of HOVENSA's crude oil purchases from suppliers other than PDVSA. At December 31, 2002, this amount was $280 million. This amount fluctuates based on the volume of crude oil purchased and the related crude oil prices. The year-end amount guaranteed is not representative of the normal contingent obligation, because reduced crude oil shipments from Venezuela in December caused HOVENSA to purchase additional crude oil from other parties. Generally, this contingent obligation is approximately $100 million.

In addition, the Corporation has agreed to provide funding, in proportion to its 50% interest, to the extent HOVENSA does not have funds to meet its senior debt obligations due prior to the completion of coker construction, as defined. At December 31, 2002, the Corporation’s pro-rata share of HOVENSA’s senior debt was $221 million, after deducting HOVENSA funds available for debt service. After completion of the coker construction project, this amount becomes $40 million until completion of construction required to meet final low sulfur fuel regulations, after which the amount reduces to $15 million.

At formation of the joint venture, PDVSA V.I., a wholly-owned subsidiary of PDVSA, purchased a 50% interest in the fixed assets of the Corporation’s Virgin Islands refinery for $62.5 million in cash and a 10-year note from PDVSA V.I. for $562.5 million bearing interest at 8.46% per annum and requiring principal payments over its term. At December 31, 2002 and December 31, 2001, the principal balance of the note was $395 million and $443 million, respectively. In October 2002, the Corporation cancelled the $125 million contingent note of PDVSA V.I. also issued to it in connection with the formation of HOVENSA. The contingent note was not valued for accounting purposes and its cancellation had no effect on the Corporation’s financial position. At the same time, there were amendments of certain contracts relating to the HOVENSA joint venture, including a six-year extension of the contract for the supply of Mesa crude oil by an affiliate of PDVSA, an amendment to the pricing formula for the Merey crude oil supplied by an affiliate of PDVSA and an amendment to the services agreement between the Corporation and HOVENSA.

7. Property, Plant and Equipment

Property, plant and equipment at December 31 consists of the following:

	2002	2001
	(Millions of dollars)	
Exploration and production		
Unproved properties	$ 1,020	$ 1,099
Proved properties	2,843	3,804
Wells, equipment and related facilities	10,836	10,291
Refining and marketing	1,450	1,433
Total — at cost	16,149	16,627
Less reserves for depreciation, depletion, amortization and lease impairment	9,117	8,462
Property, plant and equipment, net	$ 7,032	$ 8,165

8. Short-Term Notes and Related Lines of Credit

Short-term notes payable to banks amounted to $2 million at December 31, 2002 and $106 million at December 31, 2001. The weighted average interest rates on these borrowings were 1.4% and 2.5% at December 31, 2002 and 2001, respectively. At December 31, 2002, the Corporation has uncommitted arrangements with banks for unused lines of credit aggregating $206 million.

9. Long-Term Debt

Long-term debt at December 31 consists of the following:

	2002	2001
	(Millions of dollars)	
Fixed rate debentures, weighted average rate 6.9%, due through 2033	$4,237	$3,986
6.1% Marine Terminal Revenue Bonds — Series 1994 — City of Valdez, Alaska, due 2024	20	20
Pollution Control Revenue Bonds, weighted average rate 5.9%, due through 2032	53	53
Fixed rate notes, payable principally to insurance companies, weighted average rate 8.4%, due through 2014	450	645
Revolving Credit Facility with banks	—	32
Commercial paper	—	539
Project lease financing, weighted average rate 5.1%, due through 2014	169	174
Notes payable for asset purchases	—	98
Capitalized lease obligations, weighted average rate 6.5%, due through 2009	56	7
Other loans, weighted average rate 9.2%, due through 2019	5	5
	4,990	5,559
Less amount included in current maturities	14	276
Total	$4,976	$5,283

The aggregate long-term debt maturing during the next five years is as follows (in millions): 2003 — $14 (included in current liabilities); 2004 — $465; 2005 — $158; 2006 — $536 and 2007 — $290.

The Corporation's long-term debt agreements contain restrictions on the amount of total borrowings and cash dividends allowed. At December 31, 2002, the Corporation is permitted to borrow an additional $1.9 billion for the construction or acquisition of assets. At year-end, the amount that can be borrowed for the payment of dividends is $720 million.

During 2002, the Corporation refinanced existing debt by the issuance of $600 million of public debentures bearing interest at 7.125%, due in 2033. At December 31, 2002, the Corporation's public fixed rate debentures have a face value of $4,255 million ($4,237 million net of unamortized discount). Borrowings are due commencing in 2004 and extend through 2033. Interest rates on the debentures range from 5.3% to 7.9% and have a weighted average rate of 6.9%.

In connection with the sale of the Corporation's interest in the Trans Alaska Pipeline in January 2003, $20 million of Marine Terminal Revenue Bonds have been assumed by the purchaser.

The Corporation has a $1.5 billion revolving credit agreement, which was unutilized at December 31 and expires in January 2006. Borrowings under the facility bear interest at .725% above the London Interbank Offered Rate. A facility fee of .15% per annum is currently payable on the amount of the credit line. The interest rate and facility fee would be increased if the Corporation's public debt rating is lowered.

In 2002, 2001 and 2000, the Corporation capitalized interest of $101 million, $44 million and $3 million, respectively, on major development projects. The total amount of interest paid (net of amounts capitalized), principally on short-term and long-term debt, in 2002, 2001 and 2000 was $274 million, $121 million and $168 million, respectively.

10. Stock Based Compensation Plans

The Corporation has outstanding stock options and nonvested common stock under its Amended and Restated 1995 Long-Term Incentive Plan. Generally, stock options vest one year from the date of grant and the exercise price equals or exceeds the market price on the date of grant. Nonvested common stock vests five years from the date of grant.

The Corporation’s stock option activity in 2002, 2001 and 2000 consisted of the following:

	Options	Weighted-Average Exercise Price Per Share
	(Thousands)	
Outstanding at January 1, 2000	4,507	$56.18
Granted	870	60.39
Exercised	(1,082)	54.41
Outstanding at December 31, 2000	4,295	57.47
Granted	1,674	60.91
Exercised	(1,053)	56.28
Forfeited	(42)	61.79
Outstanding at December 31, 2001	4,874	58.87
Granted	46	66.45
Exercised	(492)	57.81
Forfeited	(53)	59.79
Outstanding at December 31, 2002	4,375	$59.06
Exercisable at December 31, 2000	3,425	$56.73
Exercisable at December 31, 2001	3,216	57.85
Exercisable at December 31, 2002	4,329	58.99

Exercise prices for employee stock options at December 31, 2002 ranged from $49.19 to $84.61 per share. The weighted-average remaining contractual life of employee stock options is 7 years.

The Corporation uses the Black-Scholes model to estimate the fair value of employee stock options for pro forma disclosure of the effects on net income and earnings per share. The Corporation used the following weighted-average assumptions in the Black-Scholes model for 2002, 2001 and 2000, respectively: risk-free interest rates of 4.2%, 4.1% and 5.4%; expected stock price volatility of .262, .244 and .225; dividend yield of 1.9%, 2.0% and 1.0%; and an expected life of seven years. The Corporation’s net income would have been reduced by approximately $14 million in 2002 and 2001 and $17 million in 2000 if option expense were recorded using the fair value method.

The weighted-average fair values of options granted for which the exercise price equaled the market price on the date of grant were $19.63 in 2002, $16.20 in 2001 and $20.04 in 2000.

Total compensation expense for nonvested common stock was $7 million in 2002, $12 million in 2001 and $7 million in 2000. Awards of nonvested common stock were as follows:

	Shares of Nonvested Common Stock Awarded	Weighted-Average Price on Date of Grant
	(Thousands)	
Granted in 2000	519	$59.65
Granted in 2001	108	67.25
Granted in 2002	21	66.29

At December 31, 2002, the number of common shares reserved for issuance is as follows (in thousands):

1995 Long-Term Incentive Plan	
Future awards	937*
Stock options outstanding	4,375
Stock appreciation rights	15
Total	5,327

* In February 2003, the Corporation awarded 742,500 shares of non-vested common stock.

11. Foreign Currency Translation

Foreign currency gains (losses) from continuing operations before income taxes amounted to $26 million in 2002 and $(22) million in 2001. In 2000, foreign currency gains amounted to $71 million, including a gain of $86 million related to the termination of the proposed acquisition of another oil company.

The balance in accumulated other comprehensive income related to foreign currency translation was a reduction in stockholders' equity of $107 million at December 31, 2002 compared with a reduction of $141 million at December 31, 2001.

12. Pension Plans

The Corporation has defined benefit pension plans for substantially all of its employees. The following table reconciles the benefit obligation and fair value of plan assets and shows the funded status:

	2002	2001
	(Millions of dollars)	
Reconciliation of pension benefit obligation		
Benefit obligation at January 1	$ 623	$ 589
Service cost	23	20
Interest cost	44	41
Actuarial (gain) loss	60	(5)
Acquisition of business	—	7
Benefit payments	(29)	(29)
Pension benefit obligation at December 31	721	623
Reconciliation of fair value of plan assets		
Fair value of plan assets at January 1	495	543
Actual return on plan assets	(42)	(39)
Employer contributions	63	12
Acquisition of business	—	8
Benefit payments	(29)	(29)
Fair value of plan assets at December 31	487	495
Funded status at December 31		
Funded status	(234)	(128)
Prior service cost	5	5
Unrecognized loss	214	76
Net amount recognized	$ (15)	$ (47)

Amounts recognized in the consolidated balance sheet at December 31 consists of the following:

	2002	2001
	(Millions of dollars)	
Accrued benefit liability	$(130)	$(47)
Intangible asset	5	—
Accumulated other comprehensive income	110	—
Net amount recognized	$ (15)	$(47)

Pension expense consisted of the following:

	2002	2001	2000
		(Millions of dollars)	
Service cost	$ 23	$ 20	$ 18
Interest cost	44	41	37
Expected return on plan assets	(44)	(48)	(45)
Amortization of prior service cost	1	1	2
Amortization of net (gain) loss	5	—	(1)
Pension expense*	$ 29	$ 14	$ 11

* Pension expense is expected to increase to approximately $50 million in 2003.

Prior service costs and gains and losses in excess of 10% of the greater of the benefit obligation or the market value of assets are amortized over the average remaining service period of active employees.

The weighted-average actuarial assumptions used by the Corporation's pension plans at December 31 were as follows:

	2002	2001
Discount rate	6.6%	7.0%
Expected long-term rate of return on plan assets	9.0*	9.0
Rate of compensation increases	4.4	4.5

* Decreased to 8.5% effective January 1, 2003.

The Corporation also has a nonqualified supplemental pension plan covering certain employees. The supplemental pension plan provides for incremental pension payments from the Corporation's funds so that total pension payments equal amounts that would have been payable from the Corporation's principal pension plan were it not for limitations imposed by income tax regulations. The benefit obligation related to this unfunded plan totaled $61 million at December 31, 2002 and $59 million at December 31, 2001. Pension expense for the plan was $8 million in 2002, $9 million in 2001 and $7 million in 2000. The Corporation has accrued $43 million for this plan at December 31, 2002 ($44 million at December 31, 2001). The trust established to fund the supplemental plan held assets valued at $26 million at December 31, 2002 and $23 million at December 31, 2001.

13. Provision for Income Taxes

The provision for income taxes on income from continuing operations consisted of:

	2002	2001	2000
		(Millions of dollars)	
United States Federal			
Current	$ 30	$ 57	$ 54
Deferred	(158)	50	62
State	5	27	22
	(123)	134	138
Foreign			
Current	401	355	358
Deferred	(141)	13	95
	260	368	453
Adjustment of deferred tax liability for foreign income tax rate change	43	—	—
Total from continuing operations	$ 180	$502*	$591

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* Includes benefit of $48 million relating to prior year refunds of United Kingdom Advance Corporation Taxes and deductions for exploratory drilling.

Income (loss) from continuing operations before income taxes consisted of the following:

	2002	2001	2000
		(Millions of dollars)	
United States	$(378)	$ 330	$ 395
Foreign*	313	988	1,113
Total from continuing operations	$ (65)	$1,318	$1,508

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* Foreign income includes the Corporation's Virgin Islands, shipping and other operations located outside of the United States.

Deferred income taxes arise from temporary differences between the tax basis of assets and liabilities and their recorded amounts in the financial statements. A summary of the components of deferred tax liabilities and assets at December 31 follows:

	2002	2001
	(Millions of dollars)	
Deferred tax liabilities		
Fixed assets and investments	$ 943	$1,168
Foreign petroleum taxes	256	209
Other	138	118
Total deferred tax liabilities	1,337	1,495
Deferred tax assets		
Accrued liabilities	124	176
Net operating and capital loss carryforwards	543	350
Tax credit carryforwards	61	32
Other	33	44
Total deferred tax assets	761	602
Valuation allowance	(95)	(93)
Net deferred tax assets	666	509
Net deferred tax liabilities	$ 671	$ 986

The difference between the Corporation's effective income tax rate and the United States statutory rate is reconciled below:

	2002	2001	2000
United States statutory rate	(35.0)%	35.0%	35.0%
Effect of foreign operations, including foreign tax credits	321.5*	2.8	3.9
Loss on repurchase of bonds	(15.4)	—	—
State income taxes, net of Federal income tax benefit	8.1	1.3	.8
Prior year adjustments	(1.5)	(1.5)	(.6)
Other	(.1)	.5	.1
Total	277.6%	38.1%	39.2%

* Reflects high effective tax rates in certain foreign jurisdictions, including special taxes in the United Kingdom and Norway, and losses in other jurisdictions which were benefitted at lower rates.

The Corporation has not recorded deferred income taxes applicable to undistributed earnings of foreign subsidiaries that are expected to be indefinitely reinvested in foreign operations. Undistributed earnings amounted to approximately $1.9 billion at December 31, 2002 and include amounts which, if remitted, would result in U.S. income taxes at less than the statutory rate, because of available foreign tax credits. If the earnings of such foreign subsidiaries were not indefinitely reinvested, a deferred tax liability of approximately $150 million would have been required.

For income tax reporting at December 31, 2002, the Corporation has alternative minimum tax credit carryforwards of approximately $60 million, which can be carried forward indefinitely. At December 31, 2002, the Corporation has a net operating loss carryforward in the United States of approximately $600 million. At December 31, 2002, a net operating loss carryforward of approximately $550 million is also available to offset income from the Corporation's share of the HOVENSA joint venture and to reduce taxes on interest from the PDVSA note. In addition, a foreign exploration and production subsidiary has a net operating loss carryforward of approximately $475 million.

Income taxes paid (net of refunds) in 2002, 2001 and 2000 amounted to $410 million, $605 million and $249 million, respectively.

14. Net Income Per Share

The weighted average number of common shares used in the basic and diluted earnings per share computations are summarized below:

	2002	2001	2000
		(Thousands of shares)	
Common shares — basic	88,187	88,031	89,063
Effect of dilutive securities			
Stock options	—	468	339
Nonvested common stock	—	425	358
Convertible preferred stock	—	205	118
Common shares — diluted	88,187	89,129	89,878

Diluted common shares include shares that would be outstanding assuming the exercise of stock options, the fulfillment of restrictions on nonvested shares and the conversion of preferred stock. In 2002, the above table excludes the antidilutive effect of 424,000 stock options, 461,000 nonvested common shares and 205,000 shares of convertible preferred stock. The table also excludes the effect of out-of-the-money options on 633,000 shares, 139,000 shares and 1,063,000 shares in 2002, 2001 and 2000, respectively.

Earnings per share are as follows:

	2002	2001	2000
Basic			
Continuing operations	$(2.78)	$ 9.26	$10.29
Discontinued operations	.30	1.12	1.19
Net income (loss)	$(2.48)	$10.38	$11.48
Diluted			
Continuing operations	$(2.78)	$ 9.15	$10.20
Discontinued operations	.30	1.10	1.18
Net income (loss)	$(2.48)	$10.25	$11.38

15. Leased Assets

The Corporation and certain of its subsidiaries lease gasoline stations, tankers, floating production systems, drilling rigs, office space and other assets for varying periods. At December 31, 2002, future minimum rental payments applicable to noncancelable leases with remaining terms of one year or more (other than oil and gas leases) are as follows:

	Operating Leases	Capital Leases
	(Millions of dollars)	
2003	$ 107	$ 13
2004	100	12
2005	66	13
2006	65	13
2007	66	13
Remaining years	893	3
Total minimum lease payments	1,297	67
Less: Imputed interest	—	11
Income from subleases	18	—
Net minimum lease payments	$1,279	$ 56
Capitalized lease obligations		
Current		$ 9
Long-term		47
Total		$ 56

Certain operating leases provide an option to purchase the related property at fixed prices.

Rental expense for all operating leases, other than rentals applicable to oil and gas leases, was as follows:

	2002	2001	2000
		(Millions of dollars)	
Total rental expense	$160	$206	$199
Less income from subleases	34	63	86
Net rental expense	$126	$143	$113

16. Financial Instruments, Non-Trading and Trading Activities

On January 1, 2001, the Corporation adopted FAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* This statement requires that the Corporation recognize all derivatives on the balance sheet at fair value and establishes criteria for using derivatives as hedges.

The January 1, 2001 transition adjustment resulting from adopting FAS No. 133 was a cumulative increase in other comprehensive income of $100 million after income taxes ($145 million before income taxes). Substantially all of the transition adjustment resulted from crude oil and natural gas cash flow hedges. The transition adjustment did not have a material effect on net income or retained earnings. The accounting change also affected current assets and liabilities.

Non-Trading: The Corporation uses futures, forwards, options and swaps, individually or in combination, to reduce the effects of fluctuations in crude oil, natural gas and refined product selling prices. The Corporation also uses derivatives in its energy marketing activities to fix the purchase and selling prices of energy products. Related hedge gains or losses are an integral part of the selling or purchase prices. Generally, these derivatives are designated as hedges of expected future cash flows or forecasted transactions (cash flow hedges), and the gains or losses are recorded in other comprehensive income until the hedged transactions are recognized. The Corporation's use of fair value hedges is not material.

The Corporation reclassifies hedging gains and losses from accumulated other comprehensive income to earnings at the time the hedged transactions are recognized. In 2002, hedging increased exploration and production results by $82 million before income taxes. Results from exploration and production activities in 2001 were increased $106 million before income taxes by reclassified hedge gains. This included $82 million before income taxes associated with the transition adjustment at the beginning of the year. The ineffective portion of hedges is included in current earnings in cost of products sold. The amount of hedge ineffectiveness was not material during the years ended December 31, 2002 and 2001.

The Corporation produced 119 million barrels of crude oil and natural gas liquids and 275 million Mcf of natural gas in 2002. At December 31, 2002, the Corporation's crude oil and natural gas hedging activities included commodity futures, option and swap contracts. Crude oil hedges mature in 2003 and 2004 and cover 91 million barrels of crude oil production (29 million barrels of crude oil in 2001). The Corporation has natural gas hedges covering 35 million Mcf of natural gas production at December 31, 2002, which mature in 2003 (143 million Mcf of natural gas at December 31, 2001).

Since the contracts described above are designated as hedges and correlate to price movements of crude oil and natural gas, any gains or losses resulting from market changes will be offset by losses or gains on the Corporation's production. At December 31, 2002, net after-tax deferred losses in accumulated other comprehensive income from the Corporation's crude oil and natural gas hedging contracts expiring through 2004 were $91 million ($141 million before income taxes), including $71 million of unrealized losses. Of the net after tax deferred loss, $97 million matures during 2003. At December 31, 2001 after tax deferred gains were $249 million ($374 million before income taxes), including $164 million of unrealized gains. Creditworthiness of counterparties to hedging transactions is reviewed regularly and full performance is expected.

In its energy marketing business, the Corporation has entered into cash flow hedges to fix the purchase prices of natural gas, heating oil and electricity. The fair value of these contracts is $25 million and is included in other comprehensive income. These contracts mature generally through 2004. There is no significant concentration of credit risk with counterparties.

Commodity Trading: The Corporation, principally through a consolidated partnership, trades energy commodities, including futures, forwards, options and swaps, based on expectations of future market conditions. The Corporation's income before income taxes from trading activities, including its share of the earnings of the trading partnership amounted to $6 million in 2002, $72 million in 2001 and $37 million in 2000.

Financial Instruments: Foreign currency contracts are used to protect the Corporation from fluctuations in exchange rates. The Corporation enters into foreign currency contracts, which are not designated as hedges, and the change in fair value is included in income currently. The Corporation has $307 million of notional value foreign currency forward contracts maturing in 2003 ($136 million at December 31, 2001). Notional amounts do not quantify risk or represent assets or liabilities of the Corporation, but are used in the calculation of cash settlements under the contracts. The Corporation also has $149 million in letters of credit outstanding at December 31, 2002 ($225 million at December 31, 2001). Of the total letters of credit outstanding at December 31, 2002, $89 million represents contingent liabilities; the remaining $60 million relates to liabilities recorded on the balance sheet.

Fair Value Disclosure: The Corporation estimates the fair value of its fixed-rate notes receivable and debt generally using discounted cash flow analysis based on current interest rates for instruments with similar maturities. Interest-rate swaps and foreign currency exchange contracts are valued based on current termination values or quoted market prices of comparable contracts. The Corporation's valuation of commodity contracts considers quoted market prices where applicable. In the absence of quoted market prices, the Corporation values contracts at fair value considering time value, volatility of the underlying commodities and other factors.

The following table presents the year-end fair values of energy commodities and derivative instruments used in non-trading and trading activities:

	Fair Value At Dec. 31	
	2002	2001
	(Millions of dollars, asset (liability))	
Commodities	$ 27	$ 54
Futures and forwards		
Assets	370	154
Liabilities	(378)	(323)
Options		
Held	65	420
Written	(27)	(466)
Swaps		
Assets	1,323	1,472
Liabilities	(1,394)	(1,109)

The carrying amounts of the Corporation's financial instruments and commodity contracts, including those used in the Corporation's non-trading and trading activities, generally approximate their fair values at December 31, 2002 and 2001, except as follows:

	2002		2001	
	Balance Sheet Amount	Fair Value	Balance Sheet Amount	Fair Value
	(Millions of dollars, asset (liability))			
Fixed-rate notes receivable	$ 424	$ 364	$ 443	$ 440
Fixed-rate debt	(4,984)	(5,561)	(4,936)	(5,070)

Market and Credit Risks: The Corporation's financial instruments expose it to market and credit risks and may at times be concentrated with certain counterparties or groups of counterparties. The credit worthiness of counterparties is subject to continuing review and full performance is anticipated. In its trading activities, the Corporation reduces its risk related to certain counterparties by using master netting agreements and requiring collateral, generally cash.

In its trading activities, the Corporation has net receivables of $442 million at December 31, 2002, which are concentrated with counterparties, as follows: domestic and foreign trading companies — 40%, gas and power companies — 32%, banks and major financial institutions — 15% and integrated energy companies — 7%.

17. Future Accounting Changes

During 2002, the Emerging Issues Task Force issued EITF 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities*. In accordance with EITF 02-3, the Corporation began accounting for trading inventory purchased after October 25, 2002 at the lower of cost or market. Inventory purchased prior to this date was marked-to-market and reflected in income currently. Beginning January 1, 2003, the Corporation will account for all trading inventory at the lower of cost or market. This accounting change will not have a material effect on the Corporation's income or financial position.

The Financial Accounting Standards Board issued FAS No. 143, *Accounting for Asset Retirement Obligations*. This statement changes the method of accruing for costs associated with the retirement of fixed assets for which a legal retirement obligation exists, such as the dismantlement of oil and gas production facilities. This standard is effective in 2003. The effect of this new accounting standard is not material to the Corporation's income or financial position.

The oil and gas industry is currently discussing the appropriate balance sheet classification of oil and gas mineral rights held by lease or contract. The Corporation classifies these assets as property, plant and equipment in accordance with its interpretation of FAS No. 19 and common industry practice. There is also a view that these mineral rights are intangible assets as defined in FAS No. 141, *Business Combinations*, and, therefore, should be classified separately on the balance sheet as intangible assets. If the accounting for mineral rights held by lease or contract is ultimately changed, the Corporation believes that any such reclassification of mineral rights could amount to approximately $2.2 billion at December 31, 2002 and $3.3 billion at December 31, 2001, if the Corporation is required to include the purchase price allocated to hydrocarbon reserves obtained in acquisitions of oil and gas properties. The determination of this amount is based on the Corporation's current understanding of this evolving issue and how the provisions of FAS No. 141 might be applied to oil and gas mineral rights. This potential balance sheet reclassification would not affect results of operations or cash flows.

18. Guarantees and Contingencies

In the normal course of business, the Corporation provides guarantees for investees of the Corporation. These guarantees are contingent commitments that ensure the performance of investees for repayment of borrowings and other arrangements. The maximum potential amount of future payments that the Corporation could be required to make under its guarantees at December 31, 2002 is $269 million. The Corporation has guaranteed $221 million of the senior debt obligation of HOVENSA (see note 6). The remainder relates generally to guarantees of performance under lease terms of a natural gas pipeline in which the Corporation owns a 5% interest. The amount of this guarantee declines over a 15 year term.

The Corporation is subject to contingent liabilities with respect to existing or potential claims, lawsuits and other proceedings. The Corporation considers these routine and incidental to its business and not material to its financial position or results of operations. The Corporation accrues liabilities when the future costs are probable and reasonably estimable.

19. Subsequent Events

During 2003, the Corporation exchanged its interests in producing properties in Colombia for an increased interest in a non-producing property under development in the joint development area of Malaysia and Thailand. The Corporation also sold producing properties in the Gulf of Mexico Shelf, the Jabung Field in Indonesia and several small United Kingdom fields. Accordingly, reclassifications for discontinued operations have been made in the consolidated financial statements, notes to the financial statements and supplementary oil and gas data.

In connection with the effective date of Regulation G on March 28, 2003, the Corporation also eliminated the presentation of certain items previously characterized as "special items" in the notes to the financial statements.

As part of its initiative to monitor the public filings of Fortune 500 companies, the Staff of the Division of Corporation Finance of the Securities and Exchange Commission reviewed and commented on the Corporation's Form 10-K for the year ended December 31, 2001 and certain quarterly and current reports on Forms 10-Q and 8-K filed or furnished thereafter. The Staff also issued several comments on the Corporation's December 31, 2002 Form 10-K. This review has been completed and during 2003 the Corporation expanded certain disclosures as a result of this review in its MD&A and notes to the financial statements included in Forms 10-Q filed for the quarters ended March 31 and June 30, 2003. The Corporation has also reclassified reserves from "improved recovery" to "revisions of previous estimates" in the Oil and Gas Reserves table included in the Supplementary Oil and Gas Data. An advisory disclosure about a potential accounting interpretation that may require the balance sheet reclassification of oil and gas mineral rights is also disclosed in the notes to financial statements.

The effect of discontinued operations, compliance with Regulation G and the expanded disclosures are reflected in the financial statements, notes to the financial statements and the supplementary oil and gas data. (See notes 2, 3, 11, 13, 14, 16, 17 and 20 and the statements of consolidated income and cash flows.)

20. Segment Information

Financial information by major geographic area for each of the three years ended December 31, 2002 follows:

	United States	Europe	Africa, Asia and other	Consolidated
			(Millions of dollars)	
2002				
Operating revenues	$8,684	$2,185	$ 682	$11,551
Property, plant and equipment (net)	1,770	2,327	2,935	7,032
2001				
Operating revenues	9,663	3,081	308	13,052
Property, plant and equipment (net)	2,469	2,322	3,374	8,165
2000				
Operating revenues	8,820	2,754	173	11,747
Property, plant and equipment (net)	1,558	2,269	496	4,323

The Corporation has two operating segments that comprise the structure used by senior management to make key operating decisions and assess performance. These are (1) exploration and production and (2) refining and marketing. Operating segments have not been aggregated. Exploration and production operations include the exploration for and the production, purchase, transportation and sale of crude oil and natural gas. Refining and marketing operations include the manufacture, purchase, transportation, trading and marketing of petroleum and other energy products.

The following table presents financial data by operating segment for each of the three years ended December 31, 2002:

	Exploration and Production	Refining and Marketing	Corporate and Interest	Consolidated*
		(Millions of dollars)		
2002				
Operating revenues				
Total operating revenues	$ 3,735	$8,351	$ 1	
Less: Transfers between affiliates	536	—	—	
Operating revenues from unaffiliated customers	$ 3,199	$8,351	$ 1	$11,551
Income (loss) from continuing operations	$ (102)	$ 85	$(228)	$ (245)
Discontinued operations	40	—	(13)	27
Net income (loss)	$ (62)	$ 85	$(241)	$ (218)
Earnings of equity affiliates	$ (4)	$ (38)	$ —	$ (42)
Interest income	5	38	1	44
Interest expense	—	—	256	256
Depreciation, depletion, amortization and lease impairment	1,103	55	1	1,159
Asset impairments	1,024	—	—	1,024
Provision (benefit) for income taxes	265	47	(132)	180
Investments in equity affiliates	617	1,001	—	1,618
Identifiable assets	8,392	4,218	652	13,262
Capital employed	6,657	2,465	118	9,240
Capital expenditures	1,404	123	7	1,534
2001				
Operating revenues				
Total operating revenues	$ 4,451	$9,454	$ 2	
Less: Transfers between affiliates	855	—	—	
Operating revenues from unaffiliated customers	$ 3,596	$9,454	$ 2	$13,052
Income (loss) from continuing operations	$ 796	$ 233	$(213)	$ 816
Discontinued operations	98	—	—	98
Net income (loss)	$ 894	$ 233	$(213)	$ 914
Earnings of equity affiliates	$ (2)	$ 54	$ —	$ 52
Interest income	6	45	8	59
Interest expense	—	—	194	194
Depreciation, depletion, amortization and lease impairment	818	51	2	871
Provision (benefit) for income taxes	506	65	(69)	502
Investments in equity affiliates	580	1,052	—	1,632
Identifiable assets	10,412	4,797	160	15,369
Capital employed	7,534	2,999	39	10,572
Capital expenditures	5,061	155	5	5,221

	Exploration and Production	Refining and Marketing	Corporate and Interest	Consolidated*
	(Millions of dollars)			
2000				
Operating revenues				
Total operating revenues	$3,724	$8,813	$ 2	
Less: Transfers between affiliates	792	—	—	
Operating revenues from unaffiliated customers	$2,932	$8,813	$ 2	$11,747
Income (loss) from continuing operations	$ 762	$ 264	$(109)	$ 917
Discontinued operations	106	—	—	106
Net income (loss)	$ 868	$ 264	$(109)	$ 1,023
Earnings of equity affiliates	$ 1	$ 121	$ 6	$ 128
Interest income	7	59	11	77
Interest expense	—	—	162	162
Depreciation, depletion, amortization and lease impairment	661	39	8	708
Provision (benefit) for income taxes	554	50	(13)	591
Investments in equity affiliates	147	894	—	1,041
Identifiable assets	4,688	4,976	610	10,274
Capital employed	2,817	2,747	369	5,933
Capital expenditures	783	154	1	938

* After elimination of transactions between affiliates, which are valued at approximate market prices.

Amerada Hess Corporation and Consolidated Subsidiaries

REPORT OF MANAGEMENT

The consolidated financial statements of Amerada Hess Corporation and consolidated subsidiaries were prepared by and are the responsibility of management. These financial statements conform with generally accepted accounting principles and are, in part, based on estimates and judgements of management. Other information included in this Annual Report is consistent with that in the consolidated financial statements.

The Corporation maintains a system of internal controls designed to provide reasonable assurance that assets are safeguarded and that transactions are properly executed and recorded. Judgements are required to balance the relative costs and benefits of this system of internal controls.

The Corporation's consolidated financial statements have been audited by Ernst & Young LLP, independent auditors, who have been selected by the Audit Committee and the Board of Directors and approved by the stockholders. Ernst & Young LLP assesses the Corporation's system of internal controls and performs tests and procedures that they consider necessary to arrive at an opinion on the fairness of the consolidated financial statements.

The Audit Committee of the Board of Directors consists solely of independent directors. The Audit Committee meets periodically with the independent auditors, internal auditors and management to review and discuss the annual audit scope and plans, the adequacy of staffing, the system of internal controls and the results of examinations. At least annually, the Audit Committee meets with the independent auditors and with the internal auditors without management present. The Audit Committee also reviews the Corporation's financial statements with management and the independent auditors. This review includes a discussion of accounting principles, significant judgements inherent in the financial statements, disclosures and such other matters required by generally accepted auditing standards. Ernst & Young LLP and the Corporation's internal auditors have unrestricted access to the Audit Committee.

/s/ JOHN B. HESS

John B. Hess
Chairman of the Board and Chief Executive Officer

/s/ JOHN Y. SCHREYER

John Y. Schreyer
Executive Vice President and Chief Financial Officer

The Board of Directors and Stockholders
Amerada Hess Corporation

We have audited the accompanying consolidated balance sheet of Amerada Hess Corporation and consolidated subsidiaries as of December 31, 2002 and 2001 and the related consolidated statements of income, retained earnings, cash flows, changes in preferred stock, common stock and capital in excess of par value and comprehensive income for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the 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 financial statements referred to above present fairly, in all material respects, the consolidated financial position of Amerada Hess Corporation and consolidated subsidiaries at December 31, 2002 and 2001 and the consolidated results of their operations and their consolidated cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 16 to the consolidated financial statements, the Corporation adopted Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, effective January 1, 2001.

Ernst + Young LLP

New York, NY

February 21, 2003,
except for Note 19,
as to which the date is November 6, 2003

Amerada Hess Corporation and Consolidated Subsidiaries

SUPPLEMENTARY OIL AND GAS DATA (UNAUDITED)

The supplementary oil and gas data that follows is presented in accordance with Statement of Financial Accounting Standards (FAS) No. 69, *Disclosures about Oil and Gas Producing Activities*, and includes (1) costs incurred, capitalized costs and results of operations relating to oil and gas producing activities, (2) net proved oil and gas reserves, and (3) a standardized measure of discounted future net cash flows relating to proved oil and gas reserves, including a reconciliation of changes therein.

The Corporation produces crude oil and/or natural gas in the United States, Europe, Equatorial Guinea, Gabon, Indonesia, Thailand, Azerbaijan, Algeria and Colombia. Exploration activities are also conducted, or are planned, in additional countries.

Through an equity investee, the Corporation owns a 25% interest in certain oil and gas fields in the joint development area of Malaysia and Thailand (JDA). The Corporation also owns a 25% interest in an oil and gas exploration and production company, Premier Oil plc. The Corporation accounts for both of these investments on the equity method.

Subsequent to year-end, the Corporation exchanged its producing properties in Colombia for an additional 25% interest in the JDA. The Corporation's JDA interest will be consolidated in future periods. The Corporation has also agreed to exchange its interest in Premier for an interest in a producing gas field in Indonesia. In addition, the Corporation sold producing properties in the Gulf of Mexico Shelf, the Jabung Field in Indonesia and several small United Kingdom fields in 2003.

Costs Incurred in Oil and Gas Producing Activities

	For the Years Ended December 31			
	Total	United States	Europe	Africa, Asia and Other
	(Millions of dollars)			
2002				
Property acquisitions				
Proved	$ 70	$ —	$ —	$ 70
Unproved	23	22	—	1
Exploration	335	120	53	162
Development	1,095	146	509	440
Share of equity investees' costs incurred	39	—	25	14
2001				
Property acquisitions				
Proved	2,772	831	—	1,941
Unproved	820	121	1	698
Exploration	297	107	87	103
Development	1,182	322	516	344
Share of equity investees' costs incurred	14	—	9	5
2000				
Property acquisitions				
Proved	80	—	—	80
Unproved	38	22	8	8
Exploration	252	119	49	84
Development	536	155	321	60
Share of equity investees' costs incurred	49	—	9	40

Capitalized Costs Relating to Oil and Gas Producing Activities

	At December 31	
	2002	2001
	(Millions of dollars)	
Unproved properties	$ 1,020	$ 1,099
Proved properties	2,843	3,804
Wells, equipment and related facilities	10,836	10,291
Total costs	14,699	15,194
Less: Reserve for depreciation, depletion, amortization and lease impairment	8,539	7,907
Net capitalized costs	$ 6,160	$ 7,287
Share of equity investees' capitalized costs	$ 704	$ 655

The results of operations for oil and gas producing activities shown below exclude sales of purchased natural gas, non-operating income (including gains on sales of oil and gas properties), interest expense and gains and losses resulting from foreign exchange transactions. Therefore, these results are on a different basis than the net income from exploration and production operations reported in management's discussion and analysis of results of operations and in Note 20 to the financial statements.

Results of Operations for Oil and Gas Producing Activities

	For the Years Ended December 31			
	Total	United States	Europe	Africa, Asia and Other
	(Millions of dollars)			
2002				
Sales and other operating revenues				
Unaffiliated customers	$2,766	$ 365	$1,768	$ 633
Inter-company	568	536	32	—
Total revenues	3,334	901	1,800	633
Costs and expenses				
Production expenses, including related taxes	736	208	387	141
Exploration expenses, including dry holes and lease impairment	316	85	94	137
Other operating expenses	105	45	16	44
Depreciation, depletion and amortization	1,061	345	518	198
Asset impairments	1,024	318	—	706
Total costs and expenses	3,242	1,001	1,015	1,226
Results of continuing operations before income taxes	92	(100)	785	(593)
Provision for income taxes	225	(33)	376	(118)
Results of continuing operations	(133)	(67)	409	(475)
Discontinued operations	52	(51)	14	89
Results of operations	$ (81)	$ (118)	$ 423	$ (386)
Share of equity investees' results of operations	$ 8	$ —	$ (3)	$ 11

	For the Years Ended December 31			
	Total	United States	Europe	Africa, Asia and Other
	(Millions of dollars)			
2001				
Sales and other operating revenues				
Unaffiliated customers	$2,154	$ 216	$1,650	$288
Inter-company	1,032	856	176	—
Total revenues	3,186	1,072	1,826	288
Costs and expenses				
Production expenses, including related taxes	642	190	350	102
Exploration expenses, including dry holes and lease impairment	347	138	103	106
Other operating expenses	139	78	25	36
Depreciation, depletion and amortization	780	292	437	51
Total costs and expenses	1,908	698	915	295
Results of continuing operations before income taxes	1,278	374	911	(7)
Provision for income taxes	490	128	313	49
Results of continuing operations	788	246	598	(56)
Discontinued operations	95	28	16	51
Results of operations	$ 883	$ 274	$ 614	$ (5)
Share of equity investees' results of operations	$ 17	$ —	$ 12	$ 5
2000				
Sales, and other operating revenues				
Unaffiliated customers	$1,904	$ 13	$1,739	$152
Inter-company	944	792	152	—
Total revenues	2,848	805	1,891	152
Costs and expenses				
Production expenses, including related taxes	522	137	344	41
Exploration expenses, including dry holes and lease impairment	282	138	51	93
Other operating expenses	84	43	20	21
Depreciation, depletion and amortization	629	158	443	28
Total costs and expenses	1,517	476	858	183
Results of continuing operations before income taxes	1,331	329	1,033	(31)
Provision for income taxes	554	123	427	4
Results of continuing operations	777	206	606	(35)
Discontinued operations	108	67	35	6
Results of operations	$ 885	$ 273	$ 641	$ (29)
Share of equity investees' results of operations	$ 2	$ —	$ (3)	$ 5

The Corporation's net oil and gas reserves have been estimated by independent consultants DeGolyer and MacNaughton. The reserves in the tabulation below include proved undeveloped crude oil and natural gas reserves that will require substantial future development expenditures. On a barrel of oil equivalent basis, 33% of the Corporation's December 31, 2002 worldwide proved reserves are undeveloped. The estimates of the Corporation's proved reserves of crude oil and natural gas (after deducting royalties and operations interests owned by others) follow:

Oil and Gas Reserves

	Crude Oil, Condensate and Natural Gas Liquids (Millions of barrels)						Natural Gas (Millions of Mcf)					
	United States	**Europe**	**Africa, Asia and other**	**Total**	**Equity Investees**	**World-wide**	**United States**	**Europe**	**Africa, Asia and other**	**Total**	**Equity Investees**	**World-wide**
Net Proved Developed and Undeveloped Reserves												
At January 1, 2000	163	438	97	698	14	712	605	998	301	1,904	277	2,181
Revisions of previous estimates	9	31	5	45	(1)	44	2	33	7	42	2	44
Extensions, discoveries and other additions	7	16	4	27	—	27	43	47	14	104	44	148
Purchases of minerals in-place	1	4	83	88	—	88	8	2	—	10	—	10
Sales of minerals in-place	—	(5)	(2)	(7)	—	(7)	—	(4)	—	(4)	—	(4)
Production	(24)	(65)	(7)	(96)	(2)	(98)	(106)	(131)	(12)	(249)	(3)	(252)
At December 31, 2000	156	419	180	755	11	766	552	945	310	1,807	320	2,127
Revisions of previous estimates	3	(1)	4	6	(1)	5	31	(25)	(17)	(11)	46	35
Improved recovery	—	34	—	34	—	34	—	27	—	27	—	27
Extensions, discoveries and other additions	9	18	8	35	—	35	62	196	33	291	—	291
Purchases of minerals in-place	22	1	190	213	13	226	227	—	10	237	493	730
Sales of minerals in-place	—	—	—	—	—	—	—	(1)	—	(1)	(25)	(26)
Production	(28)	(63)	(18)	(109)	(2)	(111)	(155)	(131)	(10)	(296)	(7)	(303)
At December 31, 2001	162	408	364	934	21	955	717	1,011	326	2,054	827	2,881
Revisions of previous estimates(a)	(10)	7	(73)	(76)	(5)	(81)	(82)	(16)	8	(90)	(81)	(171)
Extensions, discoveries and other additions	13	11	15	39	—	39	69	24	31	124	3	127
Sales of minerals in-place	(3)	(1)	(6)	(10)	—	(10)	(29)	(43)	—	(72)	—	(72)
Production	(24)	(61)	(34)	(119)	(2)	(121)	(136)	(124)	(15)	(275)	(13)	(288)
At December 31, 2002	138	364	266	768	14(d)	782(b)	539(c)	852	350	1,741	736(d)	2,477(b)
Reserves at December 31, 2002 related to discontinued operations in 2003	7	9	82	98	—	98	119	1	157	277	—	277
Net Proved Developed Reserves												
At January 1, 2000	136	351	26	513	10	523	477	841	119	1,437	87	1,524
At December 31, 2000	140	353	80	573	9	582	476	842	111	1,429	199	1,628
At December 31, 2001	144	318	196	658	7	665	580	709	111	1,400	220	1,620
At December 31, 2002	113	294	140	547	8	555	450	631	154	1,235	221	1,456

(a) Revisions include reductions of approximately 44 million barrels of crude oil and 26 million Mcf of natural gas relating to the impact of higher selling prices on production sharing contracts with cost recovery provisions and stipulated rates of return. Also includes reductions in reserves on fields acquired in the LLOG and Triton acquisitions.

(b) Includes 27% of crude oil reserves and 33% of natural gas reserves held under production sharing contracts. These reserves are located outside of the United States and are subject to different political and economic risks.

(c) Excludes 443 million Mcf of carbon dioxide gas for sale or use in company operations.

(d) Substantially all of these reserves are outside of the United States and Europe.

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves required to be disclosed by FAS No. 69 is based on assumptions and judgements. As a result, the future net cash flow estimates are highly subjective and could be materially different if other assumptions were used. Therefore, caution should be exercised in the use of the data presented below.

Future net cash flows are calculated by applying year-end oil and gas selling prices (adjusted for price changes provided by contractual arrangements) to estimated future production of proved oil and gas reserves, less estimated future development and production costs, which are based on year-end costs and existing economic assumptions. Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the pre-tax net cash flows relating to the Corporation's proved oil and gas reserves. Future net cash flows are discounted at the prescribed rate of 10%. No recognition is given in the discounted future net cash flow estimates to depreciation, depletion, amortization and lease impairment, exploration expenses, interest expense, corporate general and administrative expenses and changes in future prices and costs. The selling prices of crude oil and natural gas have increased during 2002 and are highly volatile. The year-end prices which are required to be used for the discounted future net cash flows and do not include the effects of hedges may not be representative of future selling prices.

Standardized Measure of Discounted Future Net Cash Flows

Relating to Proved Oil and Gas Reserves

	At December 31			
	Total	**United States**	**Europe**	**Africa, Asia and other**
			(Millions of dollars)	
2002				
Future revenues	$27,994	$6,219	$13,203	$8,572
Less:				
Future development and production costs	10,133	1,843	4,863	3,427
Future income tax expenses	6,661	1,228	4,042	1,391
	16,794	3,071	8,905	4,818
Future net cash flows	11,200	3,148	4,298	3,754
Less: Discount at 10% annual rate	4,115	1,178	1,441	1,496
Standardized measure of discounted future net cash flows	$ 7,085	$1,970	$ 2,857	$2,258
Amount of discounted future net cash flows included above related to operations discontinued in 2003	$ 1,078	$ 238	$ 37	$ 803
Share of equity investees' standardized measure	$ 587	$ —	$ 23	$ 564
2001				
Future revenues	$22,666	$4,884	$10,569	$7,213
Less:				
Future development and production costs	10,335	1,817	4,889	3,629
Future income tax expenses	3,989	686	2,495	808
	14,324	2,503	7,384	4,437
Future net cash flows	8,342	2,381	3,185	2,776
Less: Discount at 10% annual rate	3,286	809	1,132	1,345
Standardized measure of discounted future net cash flows	$ 5,056	$1,572	$ 2,053	$1,431
Share of equity investees' standardized measure	$ 543	$ —	$ 28	$ 515

	At December 31			
	Total	United States	Europe	Africa, Asia and other
	(Millions of dollars)			
2000				
Future revenues	$25,889	$9,297	$12,433	$4,159
Less:				
Future development and production costs	8,672	1,551	4,808	2,313
Future income tax expenses	6,716	2,568	3,560	588
	15,388	4,119	8,368	2,901
Future net cash flows	10,501	5,178	4,065	1,258
Less: Discount at 10% annual rate	3,673	1,923	1,136	614
Standardized measure of discounted future net cash flows	$ 6,828	$3,255	$ 2,929	$ 644
Share of equity investees' standardized measure	$ 305	$ —	$ 44	$ 261

Changes in Standardized Measure of Discounted Future Net

Cash Flows Relating to Proved Oil and Gas Reserves

	For the Years Ended December 31		
	2002	2001	2000
	(Millions of dollars)		
Standardized measure of discounted future net cash flows at beginning of year	$ 5,056	$ 6,828	$ 5,110
Changes during the year			
Sales and transfers of oil and gas produced during year, net of production costs	(2,964)	(2,840)	(2,540)
Development costs incurred during year	1,095	1,182	536
Net changes in prices and production costs applicable to future production	5,767	(4,346)	3,349
Net change in estimated future development costs	(546)	(838)	(931)
Extensions and discoveries (including improved recovery) of oil and gas reserves, less related costs	287	521	551
Revisions of previous oil and gas reserve estimates	(939)	231	396
Purchases (sales) of minerals in-place, net	(247)	1,186	230
Accretion of discount	796	1,087	832
Net change in income taxes	(1,701)	1,943	(840)
Revision in rate or timing of future production and other changes	481	102	135
Total	2,029	(1,772)	1,718
Standardized measure of discounted future net cash flows at end of year	$ 7,085	$ 5,056	$ 6,828

Amerada Hess Corporation and Consolidated Subsidiaries

TEN-YEAR SUMMARY OF FINANCIAL DATA

	2002	2001	2000	1999(e)	1998	1997	1996	1995	1994	1993
	(Millions of dollars, except per share data)									
Statement of Consolidated Income										
Revenues and Non-operating Income										
Sales (excluding excise taxes) and other operating revenues										
Crude oil (including sales of purchased oil)	$ 2,471	$ 2,099	$ 2,022	$ 1,322	$ 836	$ 1,338	$ 1,426	$ 1,480	$ 1,178	$ 1,118
Natural gas (including sales of purchased gas)	3,078	4,503	3,239	1,800	1,645	1,306	1,241	1,005	901	835
Petroleum products	4,865	5,303	5,539	3,003	3,464	4,958	5,081	4,311	3,981	3,349
Other operating revenues	1,137	1,147	947	770	509	413	296	303	328	290
Total	11,551	13,052	11,747	6,895	6,454	8,015	8,044	7,099	6,388	5,592
Non-operating income										
Gain on asset sales	143	—	—	273	(26)	16	529(h)	96	42	—
Equity in income (loss) of HOVENSA L.L.C.	(47)	58	121	7	(16)	—	—	—	—	—
Other	85	150	165	140	83	120	125	125	49	17
Total revenues and non-operating income	11,732	13,260	12,033	7,315	6,495	8,151	8,698	7,320	6,479	5,609
Costs and expenses										
Cost of products sold	7,226	8,739	7,885	4,239	4,373	5,577	5,387	4,501	3,795	3,508
Production expenses	736	642	522	453	478	513	573	561	550	573
Marketing expenses	703	663	542	387	379	329	264	259	261	247
Exploration expenses, including dry holes and lease impairment	316	347	282	260	350	422	382	382	331	351
Other operating expenses	165	213	234	217	224	232	129	186	124	242
General and administrative expenses	253	311	222	232	271	235	237	263	230	229
Interest expense	256	194	162	158	153	136	166	247	245	157
Depreciation, depletion and amortization	1,118	833	676	610	598	595	644	693	741	614
Impairment of assets and operating leases	1,024	—	—	128	206	80	—	584(i)	—	—
Total costs and expenses	11,797	11,942	10,525	6,684	7,032	8,119	7,782	7,676	6,277	5,921
Income (loss) from continuing operations before income taxes	(65)	1,318	1,508	631	(537)	32	916	(356)	202	(312)
Provision (benefit) for income taxes	180	502	591	240	(62)	85	319	37	138	13
Income (loss) from continuing operations	(245)(a)	816(c)	917(d)	391(f)	(475)(g)	(53)	597	(393)	64	(325)
Discontinued operations	27	98	106	47	16	61	63	(1)	10	57
Net income (loss)	$ (218)	$ 914	$ 1,023	$ 438	(459)	$ 8	$ 660	$ (394)	$ 74	$ (268)
Basic Earnings (loss) per share										
Continuing operations	$ (2.78)	$ 9.26	$ 10.29	$ 4.36	$ (5.30)	$ (.58)	$ 6.45	$ (4.25)	$ .69	$ (3.52)
Net income (loss)	(2.48)	10.38	11.48	4.88	(5.12)	.08	7.13	(4.26)	.80	(2.91)
Diluted Earnings (loss) per share										
Continuing operations	$ (2.78)	$ 9.15	$ 10.20	$ 4.33	$ (5.30)	$ (.58)	$ 6.41	$ (4.25)	$ .69	$ (3.52)
Net income (loss)	(2.48)	10.25	11.38	4.85	(5.12)	.08	7.09	(4.26)	.79	(2.91)
Dividends Per Share of Common Stock	$ 1.20	$ 1.20	$ .60	$ .60	$ .60	$ .60	$ .60	$ .60	$ .60	$ .60
Weighed Average Diluted Shares Outstanding (thousands)	88,178(b)	89,129	89,878	90,280	89,585(b)	91,733	93,110	92,509(b)	92,968	92,213(b)

(a) Includes net after-tax charges aggregating $737 million ($1,024 million before income taxes), principally resulting from asset impairments. See Note 2 to consolidated financial statements.

(b) Represents basic shares.

(c) Reflects after-tax charges aggregating $31 million ($47 million before income taxes) for losses related to the bankruptcy of certain subsidiaries of Enron and accrued severance.

(d) Includes an after-tax gain of $60 million ($97 million before income taxes) on termination of acquisition, partially offset by a $24 million ($38 million before income taxes) charge for costs associated with a research and development venture.

(e) On January 1, 1999, the Corporation adopted the last-in, first-out (LIFO) inventory method for refining and marketing inventories.

(f) Includes after-tax gains on asset sales of $176 million ($274 million before income taxes) and tax benefits of $54 million, partially offset by impairment of assets and operating leases of $99 million ($128 million before income taxes).

(g) Reflects after-tax charges aggregating $263 million ($248 million before income taxes) representing impairments of assets and operating leases, a net loss on assets sales and accrued severance.

(h) After income taxes, the net gain was $421 million.

(i) After income taxes, the net charge was $416 million.

See accompanying notes to consolidated financial statements, including Note 4 on Acquisition of Triton Energy Limited in August of 2001.

Amerada Hess Corporation and Consolidated Subsidiaries

TEN-YEAR SUMMARY OF FINANCIAL DATA

	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
	(Millions of dollars, except per share data)									
Selected Balance Sheet Data at Year-End										
Cash and cash equivalents	$ 197	$ 37	$ 312	$ 41	$ 74	$ 91	$ 113	$ 56	$ 53	$ 80
Working capital	203	228	577	249	90	464	690	358	520	245
Property, plant and equipment										
Exploration and production	$14,699	$15,194	$10,499	$ 9,974	$ 9,718	$ 8,780	$ 8,233	$ 9,392	$ 9,791	$ 9,361
Refining and marketing	1,450	1,433	1,399	1,091	1,309	3,842	3,669	3,672	4,514	4,426
Total — at cost	16,149	16,627	11,898	11,065	11,027	12,622	11,902	13,064	14,305	13,787
Less reserves	9,117	8,462	7,575	7,013	6,835	7,431	6,995	7,694	7,939	7,052
Property, plant and equipment — net	$ 7,032	$ 8,165	$ 4,323	$ 4,052	$ 4,192	$ 5,191	$ 4,907	$ 5,370	$ 6,366	$ 6,735
Total assets	$13,262	$15,369	$10,274	$ 7,728	$ 7,883	$ 7,935	$ 7,784	$ 7,756	$ 8,338	$ 8,642
Total debt	4,992	5,665	2,050	2,310	2,652	2,127	1,939	2,718	3,340	3,688
Stockholders' equity	4,249	4,907	3,883	3,038	2,643	3,216	3,384	2,660	3,100	3,029
Stockholders' equity per common share	$ 47.46	$ 55.11	$ 43.58	$ 33.51	$ 29.26	$ 35.16	$ 36.35	$ 28.60	$ 33.33	$ 32.71
Summarized Statement of Cash Flows										
Net cash provided by operating activities	$ 1,965	$ 1,960	$ 1,795	$ 746	$ 519	$ 1,250	$ 808	$ 1,241	$ 957	$ 819
Cash flows from investing activities										
Capital expenditures										
Exploration and production	(1,404)	(5,061)	(783)	(727)	(1,307)	(1,158)	(788)	(626)	(532)	(755)
Refining and marketing	(130)	(160)	(155)	(70)	(132)	(188)	(73)	(66)	(64)	(593)
Total capital expenditures	(1,534)	(5,221)	(938)	(797)	(1,439)	(1,346)	(861)	(692)	(596)	(1,348)
Proceeds from sales of property, plant and equipment and other	438	16	36	397	500	61	1,040	148	74	12
Net cash provided by (used in) investing activities	(1,096)	(5,205)	(902)	(400)	(939)	(1,285)	179	(544)	(522)	(1,336)
Cash flows from financing activities										
Debt with maturities of 90 days or less — increase (decrease)	(581)	564	(131)	(1,060)	213	398	(825)	(352)	(575)	558
Debt with maturities of greater than 90 days										
Borrowings	637	2,595	20	990	441	2	—	25	290	108
Repayments	(686)	(54)	(296)	(273)	(137)	(209)	(42)	(311)	(121)	(168)
Cash dividends paid	(107)	(94)	(54)	(54)	(55)	(55)	(56)	(56)	(56)	(42)
Common stock acquired	—	(100)	(220)	—	(59)	(122)	(8)	—	—	—
Stock options exercised	28	59	59	18	—	—	—	—	—	—

Net cash provided by (used in) financing activities	(709)	2,970	(622)	(379)	403	14	(931)	(694)	(462)	456
Net increase (decrease) in cash and cash equivalents	$ 160	$ (275)	$ 271	$ (33)	$ (17)	$ (21)	$ 56	$ 3	$ (27)	$ (61)
Stockholder Data at Year-End										
Number of common shares outstanding (thousands)	89,193	88,757	88,744	90,676	90,357	91,451	93,073	93,011	92,996	92,587
Number of stockholders (based on number of holders of record)	7,272	6,481	7,709	7,416	8,959	9,591	10,153	11,294	11,506	12,000
Market price of common stock	$ 55.05	$ 62.50	$ 73.06	$ 56.75	$ 49.75	$ 54.88	$ 57.88	$ 53.00	$ 45.63	$ 45.13

Amerada Hess Corporation and Consolidated Subsidiaries

TEN-YEAR SUMMARY OF OPERATING DATA

	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Production Per Day (net)										
Crude oil (thousands of barrels)										
United States	54	63	55	55	37	35	41	52	56	60
United Kingdom	112	119	119	112	109	126	135	135	122	80
Equatorial Guinea	37	6	—	—	—	—	—	—	—	—
Norway	24	25	25	25	27	30	28	26	24	26
Denmark	23	20	25	7	—	—	—	—	—	—
Colombia	22	10	—	—	—	—	—	—	—	—
Algeria	15	13	2	—	—	—	—	—	—	—
Gabon	9	9	7	10	14	10	9	10	9	8
Indonesia	4	6	4	3	3	1	—	—	—	—
Azerbaijan	4	4	3	2	—	—	—	—	—	—
Canada and Abu Dhabi	—	—	—	—	—	—	6	17	18	22
Total	304	275	240	214	190	202	219	240	229	196
Natural gas liquids (thousands of barrels)										
United States	12	14	12	10	8	8	9	11	12	12
United Kingdom	6	7	6	5	6	6	7	7	7	4
Norway	1	1	2	2	2	2	2	1	1	1
Thailand	2	1	1	1	—	—	—	—	—	—
Canada	—	—	—	—	—	—	—	2	2	2
Total	21	23	21	18	16	16	18	21	22	19
Natural gas (thousands of Mcf)										
United States	373	424	288	338	294	312	338	402	427	502
United Kingdom	277	291	297	258	251	226	254	239	209	188
Denmark	37	43	37	3	—	—	—	—	—	—
Thailand	35	20	23	8	—	—	—	—	—	—
Norway	25	25	24	31	28	30	30	28	24	29
Indonesia	6	8	10	5	3	1	—	—	—	—
Colombia	1	1	—	—	—	—	—	—	—	—
Canada	—	—	—	—	—	—	63	215	186	168
Total	754	812	679	643	576	569	685	884	846	887
Barrels of oil equivalent (thousands of barrels per day) (e)	451	433	374	339	302	313	351	408	392	363
Well Completions (net)										
Oil wells	38	50	29	28	28	42	39	33	28	48
Gas wells	39	31	11	11	20	11	25	41	44	49
Dry holes	16	15	18	9	25	24	40	50	24	37
Productive Wells at Year-End (net)										
Oil wells	760	858	774	735	721	860	854	2,154	2,160	2,189
Gas wells	237	257	188	161	252	447	455	1,160	1,146	1,115
Total	997	1,115	962	896	973	1,307	1,309	3,314	3,306	3,304
Undeveloped Net Acreage at Year-End (thousands)										
United States	743	625	616	678	748	915	891	1,440	1,685	1,854
Foreign(a)	12,224	15,999	14,419	15,858	16,927	10,180	7,455	5,871	4,570	4,310
Total	12,967	16,624	15,035	16,536	17,675	11,095	8,346	7,311	6,255	6,164
Shipping										
Vessels owned or under charter at year-end	5	8	8	8	9	14	13	16	17	15
Total deadweight tons (thousands)	743	890	884	884	952	1,602	1,236	2,010	2,265	2,398
Refining (thousands of barrels per day)										
Amerada Hess Corporation	—	—	—	—	419(b)	411	396	377	388	351

	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
HOVENSA L.L.C.(c)	181	202	211	209	217	—	—	—	—	—
Petroleum Products Sold (thousands of barrels per day)										
Gasoline, distillates and other light products	329	322	304	284	411	436	412	401	375	291
Residual fuel oils	54	65	62	60	71	73	83	86	93	95
Total	383	387	366	344	482	509	495	487	468	386
Storage Capacity at Year-End (thousands of barrels)	36,140	36,298	37,487	38,343	56,070	87,000	86,986	89,165	94,597	94,380
Number of Employees (average)	11,662(d)	10,838	9,891	8,485	9,777	9,216	9,085	9,574	9,858	10,173

(a) Includes acreage held under production sharing contracts.

(b) Through ten months of 1998.

(c) Reflects 50% of HOVENSA refinery crude runs from November 1, 1998.

(d) Includes approximately 6,650 employees of retail operations.

(e) Includes barrels of oil equivalent production per day (in thousands) of 51 in 2002, 45 in 2001, 26 in 2000, 27 in 1999 and 25 in 1998 related to operations discontinued in 2003.

Exhibit 99(2)

REPORT OF INDEPENDENT AUDITORS

Executive Committee and Members

HOVENSA L.L.C.

We have audited the accompanying balance sheet of HOVENSA L.L.C. (the "Company") as of December 31, 2002 and 2001, and the related statements of operations and cumulative earnings, cash flows and comprehensive income (loss) for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the 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 financial statements referred to above present fairly, in all material respects, the financial position of HOVENSA L.L.C. at December 31, 2002 and 2001, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States.

Ernst & Young LLP

New York, NY

February 21, 2003