2003 ANNUAL REPORT

AMERADA HESS

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Cover: Deep water production operations in the Gulf of Mexico

FINANCIAL AND OPERATING HIGHLIGHTS

Amerada Hess Corporation and Consolidated Subsidiaries

Dollar amounts in millions, except per share data	**2003**	2002
FINANCIAL—FOR THE YEAR		
Sales and other operating revenues	**$14,311**	$11,551
Income (loss) from continuing operations	**$ 467**	$ (245)
Net income (loss)	**$ 643**	$ (218)
Net income (loss) per share—diluted	**$ 7.11**	$ (2.48)
Common stock dividends per share	**$ 1.20**	$ 1.20
Cash flow from operations	**$ 1,581**	$ 1,965
Capital expenditures	**$ 1,358**	$ 1,534
Weighted average shares outstanding—in thousands	**90,342**	88,187
FINANCIAL—AT YEAR-END		
Total assets	**$13,983**	$13,262
Total debt	**$ 3,941**	$ 4,992
Stockholders' equity	**$ 5,340**	$ 4,249
Debt to capitalization ratio[a]	**42.5%**	54.0%
OPERATING—FOR THE YEAR		
Production – net		
Crude oil and natural gas liquids—		
thousands of barrels per day		
United States	**55**	66
Foreign	**204**	259
Total	**259**	325
Natural gas—thousands of Mcf per day		
United States	**253**	373
Foreign	**430**	381
Total	**683**	754
Barrels of oil equivalent—		
thousands of barrels per day[b]	**373**	451
Refining and marketing—thousands of barrels per day		
Refining crude runs— HOVENSA L.L.C.[c]	**220**	181
Refined products sold	**419**	383

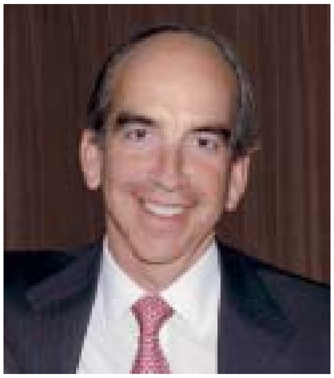
(a) *Total debt as a percentage of the sum of total debt and stockholders' equity.*

(b) *Includes production related to discontinued operations of 13 and 51 thousand barrels per day in 2003 and 2002, respectively.*

(c) *Reflects the Corporation's 50% share of HOVENSA's crude runs.*

See Management's Discussion and Analysis of Results of Operations beginning on page 15.

TO OUR STOCKHOLDERS:



“We have strengthened future profitability through an increase in new field developments, sales of lower value, mature properties and a focused, higher impact exploration program.”

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

Our strategic plan is to build a portfolio of assets that enhance financial performance and provide long-term profitable growth. We have made significant progress in the last five years to improve our competitive position both in exploration and production and refining and marketing. Exploration and production is our engine for profitable growth where we invest the majority of our capital expenditures. We have strengthened future profitability through an increase in new field developments, sales of lower value, mature properties and a focused, higher impact exploration program. We intend to continue to increase reserves and production outside the mature regions of the United States and North Sea. With respect to refining and marketing, we plan to enhance financial returns from our existing assets and to grow retail marketing opportunistically.

In 2003, our major accomplishments were:

- **MAJOR SHIFT IN EXPENDITURES TO FIELD DEVELOPMENTS**
  Over the past several years we have significantly shifted our exploration and production capital expenditures to field developments. In 2003 we invested approximately $700 million, or 56% of our upstream capital spending in developments, and in 2004, we plan to invest approximately $900 million, or about 60% of our upstream capital expenditures in developments. These amounts compare to average annual development spending during 2000-2002 of $423 million, or 37% of upstream capital expenditures.

  We are currently investing in 12 field developments in the deepwater Gulf of Mexico, West Africa, North Sea and Southeast Asia. We estimate that these developments should add in excess of 100,000 barrels of oil equivalent per day of new production by 2006. In addition, the lower costs of this new production combined with other cost cutting initiatives should reduce unit costs by $2-3 per barrel by 2006.

- **RESHAPING OUR EXISTING ASSET PORTFOLIO**
  In 2003 we sold $545 million of assets of which $478 million were mature or high cost exploration and production properties. We sold our interests in the shallow water Gulf of Mexico, the Jabung Field in Indonesia, and in several small fields in the United Kingdom sector of the North Sea.

  We also completed three significant asset swaps in 2003. In the first, we swapped mature, high cost assets in Colombia for a 25% interest in significant, long-lived natural gas reserves in the Malaysia-Thailand Joint Development Area, bringing our interest in the area to 50%. In the second transaction, we transferred a 14% interest and the operatorship of the Scott and Telford Fields in the North Sea in exchange for an additional 22.5% interest in the Llano Field in the deepwater

Gulf of Mexico, bringing our interest in the field to 50%. We also exchanged our 25% stake in Premier Oil plc for a 23% interest in the Natuna Sea Block A in Indonesia.

- **RESTRUCTURING OUR EXPLORATION AND PRODUCTION ORGANIZATION**

Last year we took steps to restructure our exploration and production business. As part of this reorganization, we reduced headcount by about 30%, or roughly 700 positions. As a result, we expect to achieve annual after-tax cost savings of $30 million. Sixty percent of these savings are expected to be realized in 2004, and the full amount in 2005.

- **CREATING VALUE THROUGH FOCUSED, HIGH-IMPACT EXPLORATION**

Our exploration strategy is to drill fewer, but higher impact wells than in the past. In 2004, we expect to drill about 15 high impact exploration and appraisal wells. In 2004, over one half of our exploration activity will be in the deepwater Gulf of Mexico.

Last year we announced several discoveries, including two significant deepwater Gulf of Mexico wells: the successful appraisal of our Shenzi discovery, in which we have a 28% interest and which encountered about 500 feet of net oil pay, and Tubular Bells, in which we have a 20% interest. Both Shenzi and Tubular Bells will be further appraised in 2004.

- **REFINING AND MARKETING**

Our refining and marketing business posted its best annual results in a decade. Earnings at HOVENSA, our refining joint venture in the U.S. Virgin Islands, and our retail and energy marketing businesses were strong.

Net income per barrel of refined products sold ranked in the top quartile versus competitors for 2003. The first quarter of 2004 has started well, and we anticipate another year of strong financial performance for our refining and marketing business.

- **STRENGTHENING OUR FINANCIAL POSITION**

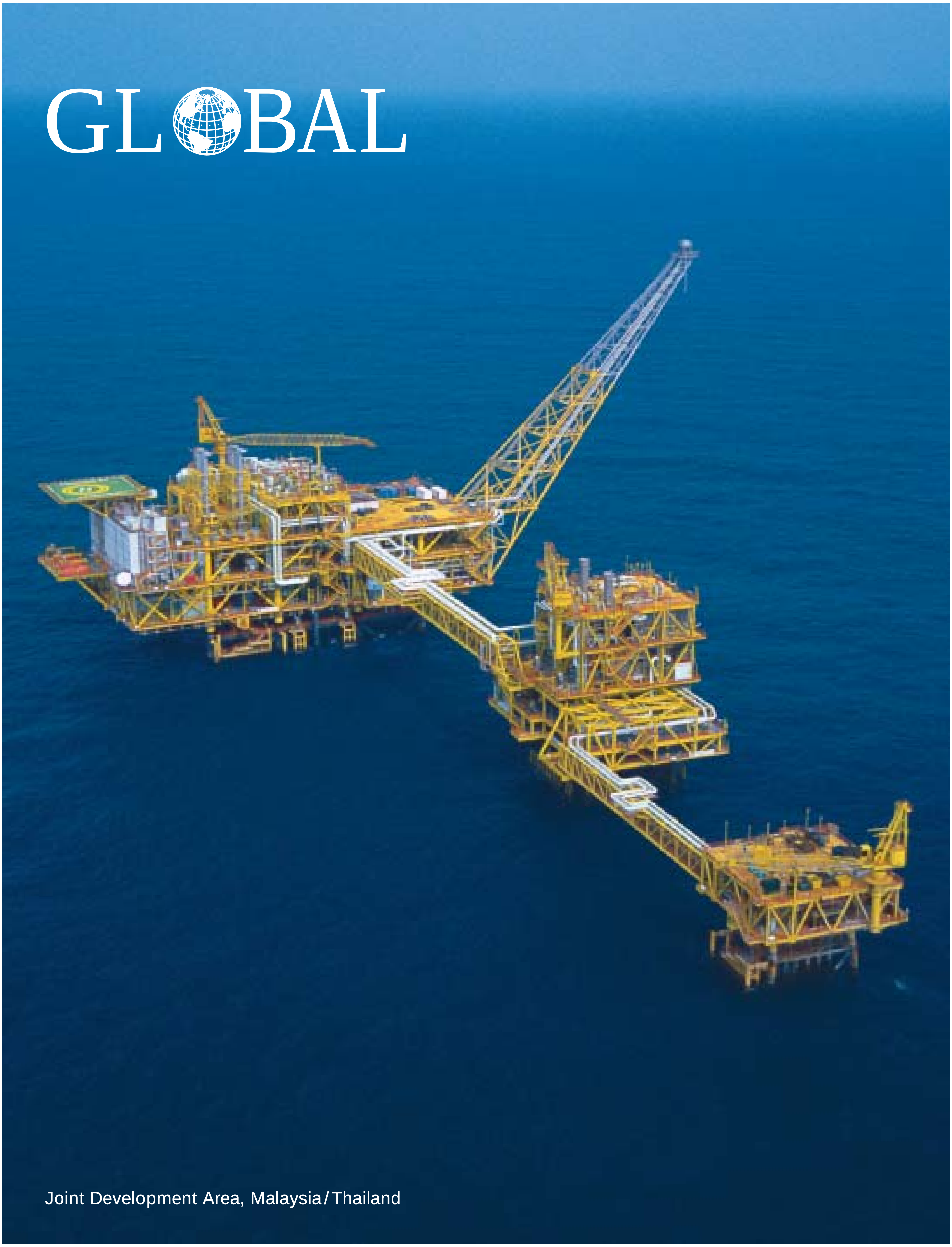
We significantly strengthened the Corporation's financial position in 2003. Proceeds from asset sales totaled $545 million; we generated free cash flow, after capital spending and dividends, in excess of $150 million, and during the fourth quarter we issued $675 million of Mandatory Convertible Preferred Stock. These steps allowed us to reduce debt by over $1 billion in 2003 and resulted in our year-end debt to capitalization ratio declining to 42.5% from 54% at the end of 2002. With $518 million of cash at the end of the year, an undrawn credit facility of $1.5 billion and negligible debt maturities over the next several years, we believe that we will have ample liquidity and financial flexibility for the foreseeable future.

We deeply appreciate the many contributions and dedication of our employees. We are grateful to our directors for their advice and guidance. We thank our shareholders for their continued support.

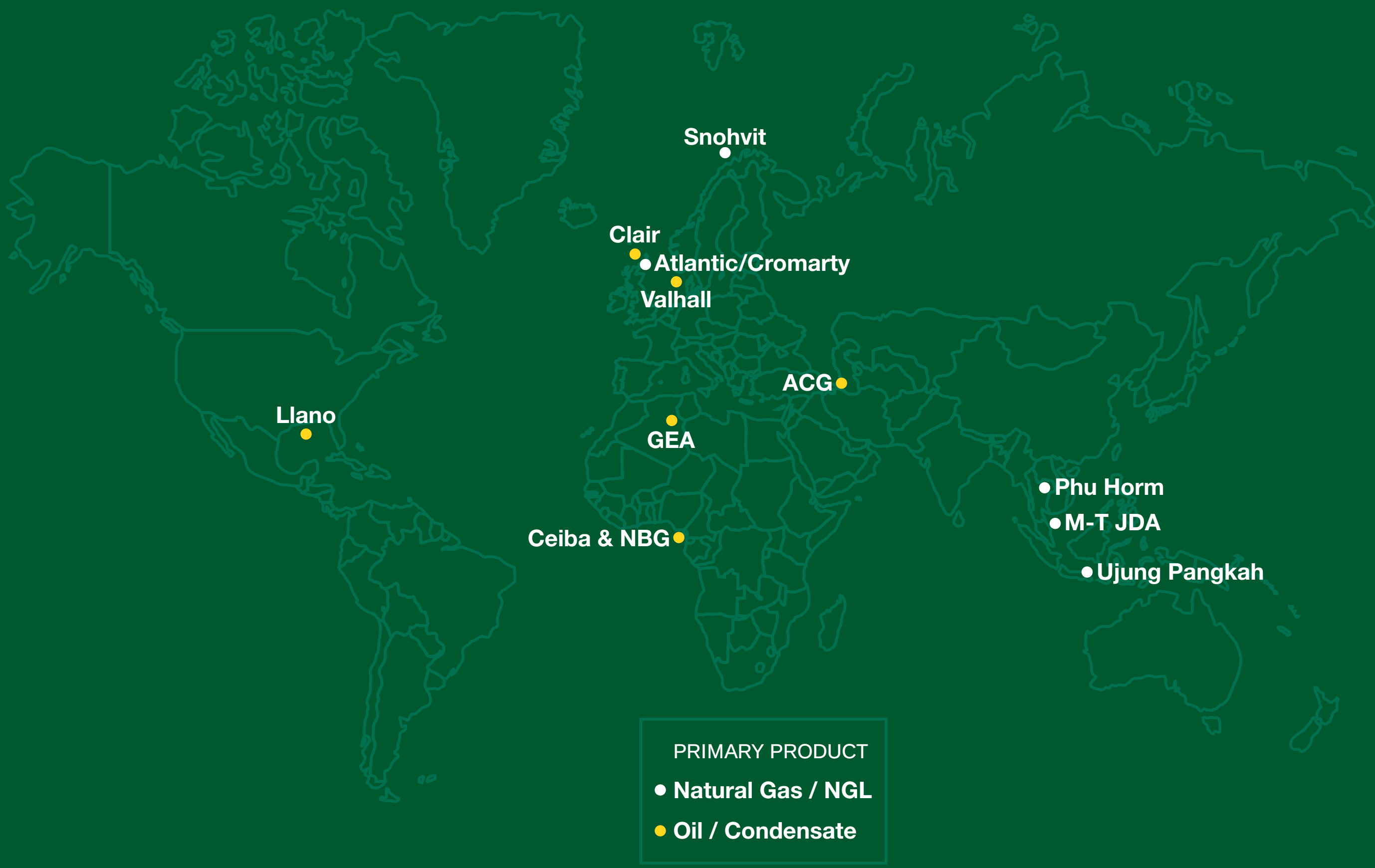
John B. Hess

JOHN B. HESS
Chairman of the Board
and Chief Executive Officer
March 3, 2004

GLOBAL



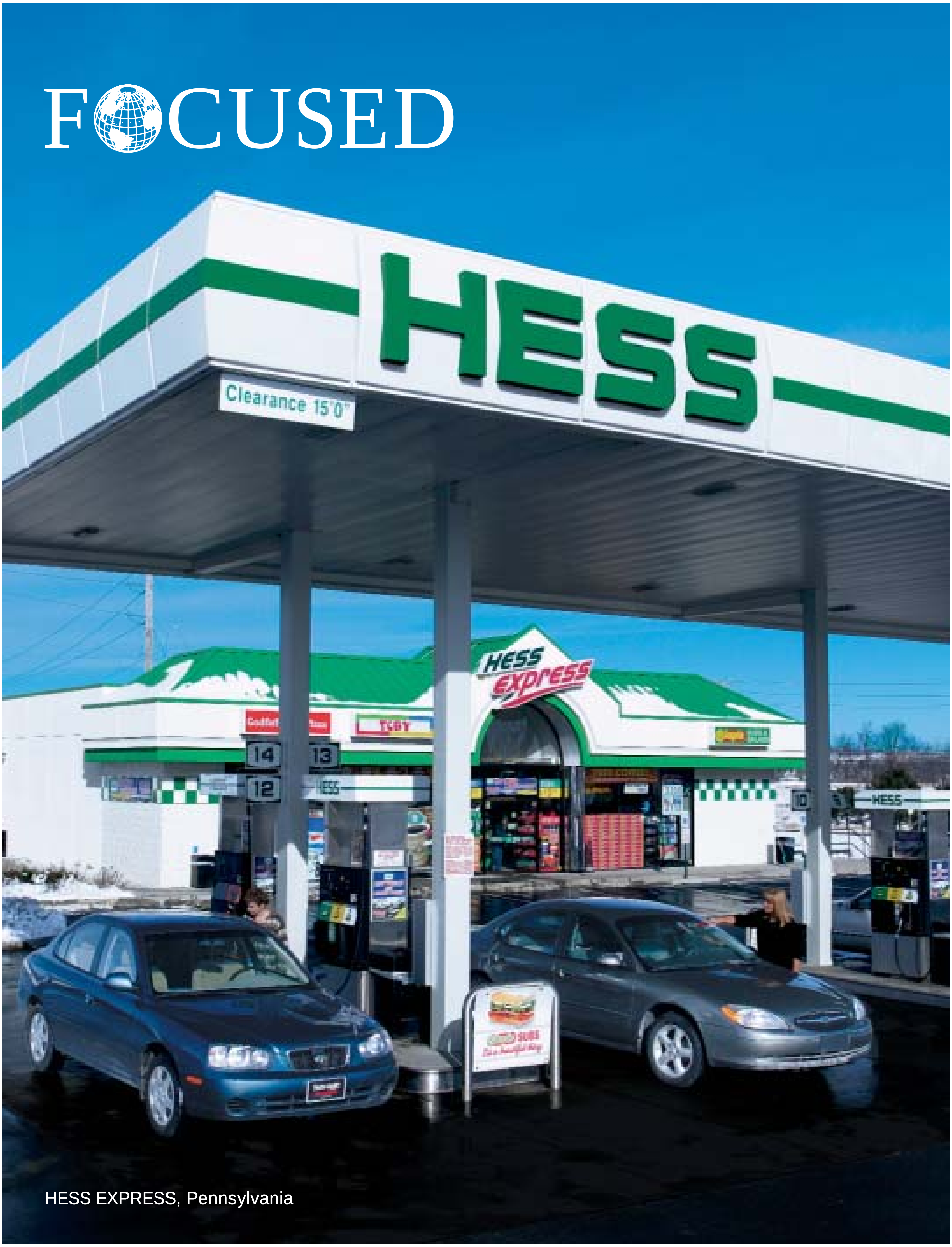
Joint Development Area, Malaysia / Thailand



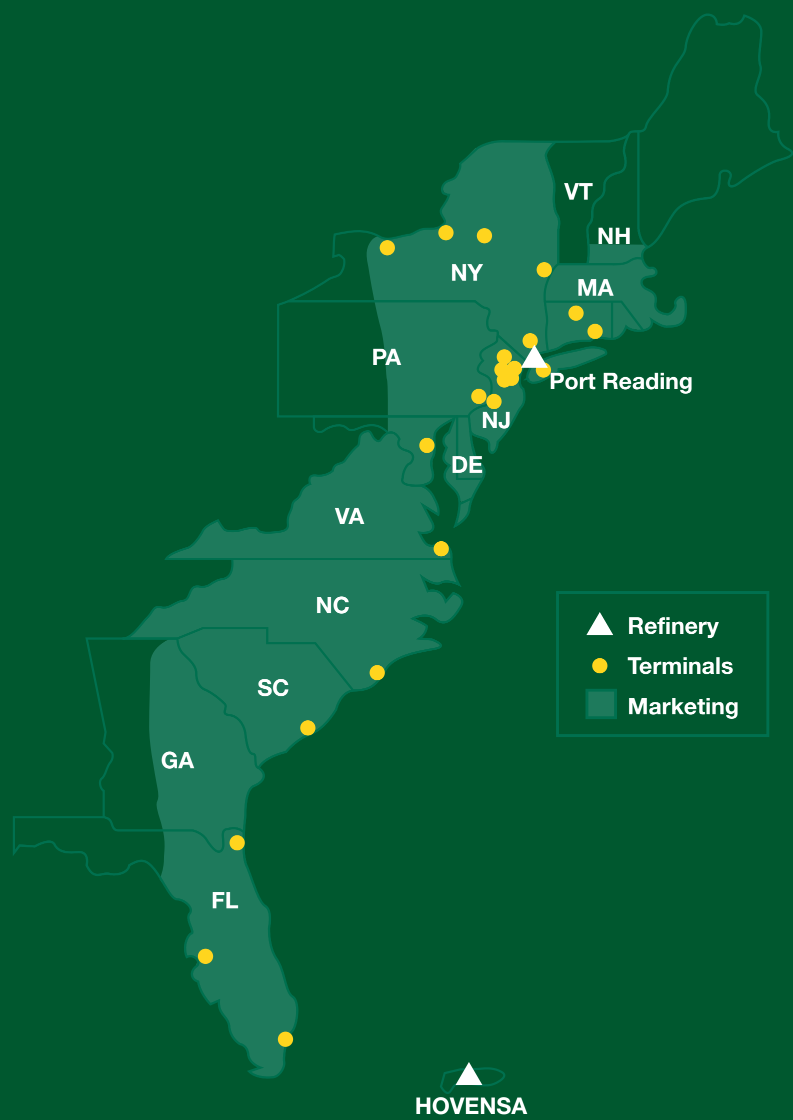
PROFITABLE GROWTH WILL BE DRIVEN BY NEW DEVELOPMENT PROJECTS

We have built an inventory of global development projects which combined with recent exploration successes will profitably grow our business for the long-term.

FOCUSED

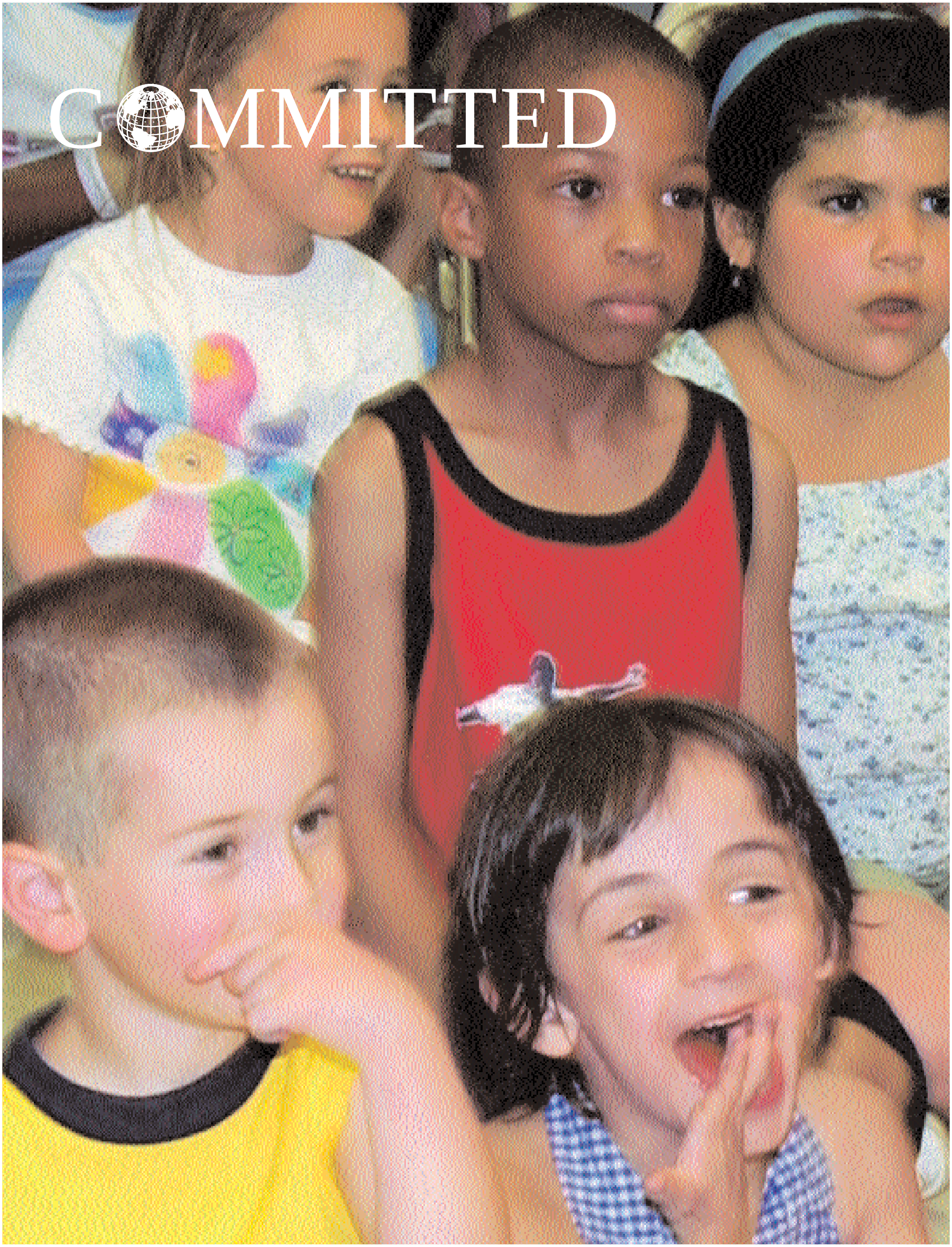


HESS EXPRESS, Pennsylvania



BUILDING THE HESS BRAND

Our Refining and Marketing business is focused on the East Coast with a growing convenience store network, an expanding energy marketing business, a world class merchant refinery and strategically located terminals.


COMMITTED

CORPORATE AND SOCIAL RESPONSIBILITY

Our goal is to help provide the world with affordable energy in an environmentally and socially responsible manner. We are committed to meeting the highest standards of corporate citizenship by protecting the health and safety of our employees, by safeguarding the environment, and by creating a long-lasting, positive impact on the communities in which we operate.

In 2003 we continued to demonstrate our commitment through the support of numerous social programs with a special emphasis on health and education.

Our Exploration and Production efforts are focused on creating value for shareholders by advancing our current development projects, appraising our recent discoveries and growing our proved reserve base.

EXPLORATION & PRODUCTION

PRODUCTION

In 2003, Amerada Hess produced 373,000 barrels of oil equivalent per day. Production is expected to average 325,000 barrels of oil equivalent per day in 2004, reflecting asset sales and swaps transacted in 2003.

In the Garden Banks area of the deepwater Gulf of Mexico, total production exceeded 33,000 barrels of oil equivalent per day in 2003. Conger (AHC 37.5%) and Baldpate (AHC 50%) are key operated assets in the area.

Onshore, Amerada Hess is the leading oil producer in North Dakota. Through a combination of horizontal and infill drilling and stimulation technology, production levels have been maintained at approximately 22,000 barrels of oil equivalent per day, for the last five years.

In the Seminole San Andres unit in West Texas, Amerada Hess is an industry leader in using carbon dioxide injection technology to increase oil recovery. The carbon dioxide tertiary recovery project that commenced in 1983 is one of the most successful recovery projects in the region.

In the North Sea, Amerada Hess has a large production base including the Valhall Field (AHC 28.09%) in Norway, the South Arne Field (AHC 57.48%) in Denmark, and the Beryl (AHC 22.22%) and the Schiehallion (AHC 15.67%) fields in the United Kingdom. In 2003, 55% of global oil and gas production was from the North Sea.

The Ceiba Field (AHC 85%), located in Block G in Equatorial Guinea, is responding favorably to water injection and is expected to produce approximately 25,000 net barrels per day in 2004 compared to 22,000 barrels per day in 2003.

DEVELOPMENT

Amerada Hess is developing 12 new oil and gas fields with new production starting over the next three years. These developments are expected to add more than 100,000 barrels of oil equivalent production per day by 2006.

First production from the Llano Field (AHC 50%) on Garden Banks Blocks 385 and 386 in the Gulf of Mexico is scheduled for mid-2004, with initial net production expected to reach 12,000 barrels of oil equivalent per day by year end.

In Block A-18 (AHC 50%) of the Joint Development Area between Malaysia and Thailand, final approval of the buyer's pipeline and gas plant was secured and construction commenced in the second half of 2003. First production from the field is expected during the second half of 2005.

In Algeria, net production from the Gassi El Agreb redevelopment project operated by SonaHess, a joint operating company between Amerada Hess and Sonatrach, was approximately 20,000 barrels per day in 2003, an increase of more than 30% from 2002.

Tubular Bells, Gulf of Mexico

Gassi El Agreb, Algeria

In the United Kingdom, first production from the Clair Field (AHC 9.29%) is expected in 2005 and from the Atlantic (AHC 25%) and Cromarty (AHC 90%) gas fields in 2006. Combined net production from these three fields is expected to exceed 25,000 barrels of oil equivalent per day in 2006.

In the Norwegian North Sea, enhanced recovery from the Valhall Field (AHC 28.09%) has begun with flank development wells coming onstream in 2003 and water injection commencing in the first quarter of 2004. The Snohvit project (AHC 3.26%), in the Barents Sea offshore Norway, will be Europe's first LNG export facility when gas production and liquefaction begin by 2006.

In Equatorial Guinea, the results of an extended appraisal drilling program are being incorporated into the development plan for the Northern Block G discoveries (AHC 85%). It is anticipated that the development plan will be submitted for government approval in the second quarter of 2004.

Development of the giant Azeri, Chirag and Guneshli fields (AHC 2.72%), in Azerbaijan, is on schedule. Net production is currently 2,000 barrels of oil equivalent per day, and is expected to increase to over 25,000 barrels per day by 2009.

EXPLORATION

Exploration is a key component of future growth. Amerada Hess has a strong position in the deepwater Gulf of Mexico, with leasehold interests in 291 blocks and over 4,000 blocks of 3D seismic coverage. In 2003, two key discoveries were made in this area:

- Successful appraisal drilling was conducted at the 2002 Shenzi discovery (AHC 28%), on Green Canyon Block 654. The Shenzi-2 well, located in 4,238 feet of water, encountered about 500 feet of net pay. Further appraisal drilling is planned in 2004.
- The Tubular Bells discovery well (AHC 20%) in Mississippi Canyon Block 725, located in 4,300 feet of water, was drilled to a depth of 31,131 feet. The well encountered 190 feet of net oil pay. Further appraisal drilling is planned in late 2004.

In northeastern Thailand, a successful appraisal well was drilled on Phu Horm Block E5N (AHC 35%). A flow test was completed with a stabilized gas rate of 31.5 million cubic feet per day. Additional appraisal drilling is planned in 2004.

Amerada Hess made a new discovery on Block 401c (AHC 60%), in Algeria. An extensive seismic program is underway, with more drilling scheduled for the second half of 2004.

Refining and marketing continues to be an important profit and cash generator for the Corporation, with growth opportunities in both retail and energy marketing. In 2003, refining and marketing achieved its best financial performance in 10 years.

REFINING & MARKETING

REFINING

The HOVENSA refinery in the United States Virgin Islands is jointly owned by the Corporation and Petroleos de Venezuela (PDVSA). It is one of the largest refineries in the world. The facility is strategically located in the Caribbean, allowing for short crude supply lines from Venezuela, as well as easy access to U.S. Gulf and East Coast product markets.

In 2003, the refinery successfully completed the first year of operation of a 58,000 barrel per day coking unit. Gross crude runs at the refinery averaged 440,000 barrels per day for 2003, which, combined with improved refining margins, resulted in a significant improvement in financial performance versus 2002.

The Corporation’s fluid catalytic cracking unit in Port Reading, New Jersey produces high-quality, clean-burning gasoline for northeast markets. The facility averaged feedstock runs of 54,000 barrels per day and realized a significant improvement in gasoline margins over 2002.

Both refining facilities continue to produce gasoline with specifications that result in emissions well below the U.S. national average.

MARKETING

Retail

The HESS retail network has become the leading independent gasoline convenience store marketer on the East Coast. In 2003, four new locations were built, while 10 existing sites were upgraded with the addition of HESS EXPRESS convenience stores. HESS EXPRESS stores generally feature several fast food offerings and proprietary coffee/fountain programs and are major destinations for take-home bulk beverages. HESS EXPRESS gasoline volumes and convenience store sales are significantly higher than industry averages.

Fuel Oil Truck, New York City

HOVENSA, St. Croix, Virgin Islands

In early 2004, WilcoHess, LLC, the joint venture between Amerada Hess and A.T. Williams Oil Company, completed the acquisition of 50 retail facilities from Service Distributing Company, significantly strengthening our brand position in the growing North Carolina market. With that purchase, the total number of Hess branded retail facilities increased to approximately 1,250.

Energy Marketing

In energy marketing, the Corporation is a major supplier of natural gas, fuel oil and electricity, with more than 24,000 commercial and industrial customer locations primarily on the East Coast. Cold weather in the first quarter of 2003 resulted in strong margins and demand for fuel oil and natural gas, significantly improving financial results over 2002.

Supply & Terminals

The Corporation operates a network of twenty-two strategically located petroleum terminals on the East Coast of the United States. In addition to supply from our refining assets, a well-balanced combination of term and spot supply contracts provides the flexibility to manage product inventories effectively across the network. In 2003, the Corporation was able to leverage our network to provide customers superior reliability of supply during the unusually cold winter weather.

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Management's Discussion and Analysis of Results of Operations and Financial Condition

Executive Overview

The Corporation is a global integrated energy company that operates in two segments, exploration and production (E&P) and refining and marketing (R&M). The E&P segment explores for, produces and sells crude oil and natural gas. The R&M segment manufactures, trades and markets refined petroleum and other energy products.

The Corporation's long-term goal for the E&P segment is to generate profitable and sustainable growth by transitioning the asset portfolio to longer life, lower cost fields, bringing new field developments onstream and pursuing a focused, high impact exploration program. During the past three years the Corporation has reshaped its E&P asset portfolio by:

- Acquiring exploration, development and production assets in West Africa and Southeast Asia.
- Selling higher cost properties predominantly in the shallow water Gulf of Mexico and the North Sea.
- Exchanging interests in mature producing assets for increased interests in development stage assets in the joint development area of Malaysia and Thailand and deepwater Gulf of Mexico.

The asset sales and exchanges have reduced near-term production which increased unit operating costs. Production declined from 451,000 barrels of oil equivalent per day in 2002 to 373,000 barrels of oil equivalent per day in 2003. Over 60% of the reduction resulted from the absence of production from assets sold or exchanged. The remainder of the decrease was due to natural declines and poorer than expected performance of certain fields in the United States and Equatorial Guinea. Production is expected to decline in 2004 by approximately 13% due to the 2003 asset sales and swaps and natural declines in our remaining fields.

The Corporation is currently funding twelve development projects that are expected to provide over 100,000 barrels of oil equivalent per day of new production in 2006, offsetting natural declines in existing fields and providing net overall production growth. In addition, since 2002, the Corporation has participated in two deepwater Gulf of Mexico discoveries that may provide additional production beyond 2006. As a result of the development projects, the Corporation presently estimates that production will be slightly higher in 2005 than in 2004 and production will increase further in 2006. While the Corporation expects these developments to be completed as currently scheduled, development projects may be subject to unforeseen events, such as technical complexities, delays in governmental sanction and political instability.

The lower production in 2004 is not expected to result in higher 2004 unit operating costs due to cost reduction initiatives begun in 2003 and the portfolio rationalization. The Corporation believes these factors, plus increasing production from new developments, will reduce unit costs in the future.

The portfolio reshaping has reduced near-term cash flows from operations. In response, the Corporation has hedged approximately 70% and 45% of its 2004 and 2005 worldwide crude oil production to provide secure cash flow to fund the development projects. Upon completion of the projects, the Corporation expects the percentage of hedged volumes to decrease.

The R&M segment's financial results improved significantly in 2003, principally reflecting higher margins and increased sales volumes. The Corporation's strategic goals for R&M are to maximize financial returns from existing assets and to generate free cash flow. The Corporation may opportunistically add retail marketing sites in its East Coast marketing area.

The Corporation's liquidity and financial position were significantly improved in 2003. At December 31, 2002, the Corporation's debt was $5 billion and its debt to capitalization ratio was 54%. During 2003, the Corporation generated cash flow of $545 million from asset sales and $653 million from the issuance of mandatory convertible preferred stock. These actions, combined with additional free cash flow from profitable operations after funding capital expenditures, resulted in debt reduction of $1.1 billion. Year-end debt was $3.9 billion and the debt to capitalization ratio improved to 42.5%. The Corporation has $221 million of debt maturities over the next three years, and had $518 million of cash on hand at December 31, 2003.

Consolidated Results of Operations

Income from continuing operations was $467 million in 2003 compared with a loss of $245 million, including impairments, in 2002 and income of $816 million in 2001. Including income from discontinued operations, net income for 2003 was $643 million, compared with a net loss of $218 million in 2002 and net income of $914 million in 2001.

The after-tax results by major operating activity for 2003, 2002 and 2001 are summarized below:

Millions of dollars, except per share data	**2003**	2002	2001
Exploration and production	**$ 414**	$ (102)	$ 796
Refining and marketing	**327**	85	233
Corporate	**(101)**	(63)	(78)
Interest expense	**(173)**	(165)	(135)
Income (loss) from continuing operations	**467**	(245)	816
Discontinued operations			
Net gains from asset sales	**116**	—	—
Income from operations	**53**	27	98
Income from cumulative effect of accounting change	**7**	—	—
Net income (loss)	**$ 643**	$ (218)	$ 914
Income (loss) per share from continuing operations — diluted	**$5.17**	$(2.78)	$ 9.15
Net income (loss) per share — diluted	**$7.11**	$(2.48)	$10.25

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. Management believes that after-tax amounts 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.

The following items, on an after-tax basis, are included in income from continuing operations for the years 2003, 2002 and 2001:

Millions of dollars	**2003**	2002	2001
Premiums on bond repurchases	**$(34)**	$ (6)	$ —
Accrued severance and London office lease costs	**(32)**	—	(10)
United States income tax benefit	**30**	—	—
Net gains from asset sales	**11**	100	—
Asset impairments	**—**	(737)	—
Charge for increase in United Kingdom income tax rate	**—**	(43)	—
Reduction in carrying value of refining and marketing intangible assets and severance	**—**	(22)	(2)
Charge related to Enron bankruptcy	**—**	—	(19)
	$(25)	$(708)	$(31)

The items in the table above are explained on pages 18, 19 and 20. The pre-tax amounts are shown on pages 18 and 20.

Comparison of Results

Exploration and Production: After considering the exploration and production items in the preceding table (described on page 18), the remaining changes in exploration and production earnings are primarily attributable to changes in selling prices, production volumes and operating costs and exploration expenses, as discussed below.

Selling prices: Higher average selling prices of crude oil, natural gas liquids and natural gas increased exploration and production revenues from continuing operations by approximately $170 million in 2003 compared with 2002. In 2002, the change in average selling prices did not significantly affect revenues compared with 2001. The Corporation's average selling prices from continuing operations, including the effects of hedging, were as follows:

	2003	2002	2001
Crude oil (per barrel)			
United States	**$24.23**	$24.04	$23.38
Foreign	**24.93**	24.69	24.50
Natural gas liquids (per barrel)			
United States	**23.74**	16.12	18.76
Foreign	**24.09**	19.09	18.99
Natural gas (per Mcf)			
United States	**4.02**	3.72	4.02
Foreign	**3.01**	2.26	2.55

Production volumes: Lower crude oil and natural gas production volumes reduced exploration and production revenues from continuing operations in 2003 compared with 2002 by $425 million. In 2002, crude oil production was higher than in 2001 and natural gas production was lower. The net effect of these volume changes was an increase in revenues of $100 million. The Corporation's net daily worldwide production was as follows:

	2003	2002	2001
Crude oil			
(thousands of barrels per day)			
United States	**44**	54	63
Foreign	**195**	250	212
Total	**239**	304	275
Natural gas liquids			
(thousands of barrels per day)			
United States	**11**	12	14
Foreign	**9**	9	9
Total	**20**	21	23
Natural gas			
(thousands of Mcf per day)			
United States	**253**	373	424
Foreign	**430**	381	388
Total	**683**	754	812
Barrels of oil equivalent*			
(thousands of barrels per day)	**373**	451	433
Barrel of oil equivalent production related to discontinued operations	**13**	51	45

**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, decreased to 373,000 barrels per day in 2003 from 451,000 barrels per day in 2002. Approximately 60% of this decline was due to asset sales and exchanges. The remainder was principally due to natural decline, disappointing results from fields acquired in the United States in 2001 and reduced production from the Ceiba Field in Equatorial Guinea. The Corporation anticipates that its 2004 production will be approximately 13% below 2003 production of 373,000 barrels of oil equivalent per day. Approximately 16,000 barrels per day of the expected decrease is due to asset sales and exchanges in 2003 and the remainder is principally due to natural decline.

Operating costs and exploration expenses: Operating costs and exploration expenses from continuing operations increased by approximately $70 million and $330 million in 2003 and 2002 compared with the corresponding amounts in the prior years.

Production expenses increased in 2003 primarily due to the weakening of the U.S. dollar, which increased costs incurred in foreign currencies and resulted in higher expenses than in prior years. Production expenses in 2003 also reflect higher employee benefit, transportation and maintenance costs. Production expenses in 2002 were higher than in 2001 due to increased production from higher cost fields, workovers and other maintenance, and higher production volumes. Depreciation, depletion and amortization charges were lower in 2003 than in 2002, reflecting decreased production volumes and lower depreciable costs resulting from impairments in 2002. Depreciation and related charges were higher in 2002 compared to 2001, due to higher unit costs from amortization of the purchase prices of fields in Equatorial Guinea, Colombia and the United States and increased production volumes. Exploration expense was higher in 2003, reflecting increased activity in the United States and Equatorial Guinea, as well as additional lease cost amortization. Exploration expense decreased in 2002 compared with 2001, principally reflecting improved drilling results.

The Corporation's total unit cost per barrel of oil equivalent produced increased in 2003 and 2002 compared with 2001. Unit cost per barrel includes production expense, depreciation, depletion and amortization, exploration expense and administrative costs. Unit costs per barrel totaled $17.32 in 2003, $15.11 in 2002 and $13.11 in 2001. The Corporation estimates that its 2004 unit costs will approximate the 2003 amount.

Other: After-tax foreign currency losses amounted to $22 million ($4 million before income taxes) in 2003 compared with income of $6 million ($26 million before income taxes) in 2002 and a loss of $17 million ($21 million before income taxes) in 2001.

The effective income tax rate for exploration and production operations in 2003 was 51%. This includes income taxes paid in jurisdictions with rates in excess of the United States statutory rate in several producing areas, such as the United Kingdom and Norway. It also reflects an income tax deduction for the Corporation's hedging results at the U.S. statutory rate. In addition, certain expenses in foreign jurisdictions are benefited at rates equal to or below the U.S. statutory rate. Each of these factors increases the Corporation's overall exploration and production effective income tax rate. During 2002, the United Kingdom government enacted a 10% supplementary tax on profits from oil and gas production. The effect of this supplementary tax was an increase in exploration and production income taxes of approximately $60 million in 2003 and $37 million in 2002. The effective income tax rate for exploration and production operations in 2004 is expected to be in the range of 47% to 51%.

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

	After Income Taxes		
Millions of dollars	**2003**	2002	2001
Accrued severance and London office lease costs	**$(32)**	$ —	$(10)
United States income tax benefit	**30**	—	—
Gains from asset sales	**31**	34	—
Asset impairments	**—**	(737)	—
Charge for increase in United Kingdom income tax rate	**—**	(43)	—
Charge related to Enron bankruptcy	**—**	—	(19)
	$ 29	$(746)	$(29)

	Before Income Taxes		
Millions of dollars	**2003**	2002	2001
Accrued severance and London office lease costs	**$(53)**	$ —	$(15)
Gains from asset sales	**47**	41	—
Asset impairments	**—**	(1,024)	—
Charge related to Enron bankruptcy	**—**	—	(29)
	$ (6)	$ (983)	$(44)

2003: The Corporation recorded an after-tax charge of $32 million for accrued severance in the United States and United Kingdom and a reduction of leased office space in London. The pre-tax amount of this charge was $53 million, of which $32 million relates to leased office space. The remainder of $21 million relates to severance for positions that were eliminated in London, Aberdeen and Houston. Over 700 employee and contractor positions have been or will be eliminated. Approximately 240 employees are receiving severance, $15 million of which has been paid through year-end. The remainder is expected to be paid in 2004. Additional accruals for severance and lease costs of approximately $15 million before income taxes are anticipated in the first half of 2004. The annual savings from this cost reduction initiative is estimated to be approximately $50 million before income taxes. The Corporation anticipates realizing approximately sixty percent of these savings in 2004 and the full amount in 2005.

The Corporation recorded an income tax benefit of $30 million reflecting the recognition for United States income tax purposes of certain prior year foreign exploration expenses. Gains from asset sales in 2003 reflect $31 million ($47 million before income taxes) from the sale of the Corporation's 1.5% interest in the Trans Alaska Pipeline System.

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 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 reduction in estimated recoverable reserves was attributable to disappointing 2002 year-end drilling results on the western flank of the field. The reduction in probable reserves and higher estimated future development costs resulted in an asset impairment because projected discounted cash flows were less than the book value of the field, which includes allocated purchase price from the Triton acquisition.

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 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.

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.

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.

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.

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, fluctuations in foreign exchange rates and changes in tax rates.

Refining and Marketing: Earnings from refining and marketing activities amounted to $327 million in 2003, $85 million in 2002 and $233 million in 2001. 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 income was $117 million in 2003, compared with a loss of $47 million in 2002 and income of $58 million in 2001. The increase in 2003 was due to higher refining margins and sales volumes compared with 2002. Crude runs were reduced in 2002 as a result of low refining margins and the shutdown of the fluid catalytic cracking unit for approximately two months. Income taxes on the Corporation's share of HOVENSA's results were offset by available loss carryforwards.

HOVENSA's total crude runs amounted to 440,000 barrels per day in 2003, 361,000 barrels per day in 2002 and 403,000 barrels per day in 2001. In late 2002 and very early 2003, crude oil deliveries to HOVENSA were interrupted due to political disturbances in Venezuela. For the remainder of 2003, HOVENSA received contracted quantities of crude oil from PDVSA. The fluid catalytic cracking unit at HOVENSA operated at 142,000, 116,000 and 123,000 barrels per day in 2003, 2002 and 2001, respectively. The coking unit at HOVENSA commenced production in August 2002. The unit operated at the rate of 53,000 barrels per day in 2003.

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 $30 million in 2003, $35 million in 2002 and $39 million in 2001. Interest income is reflected in non-operating income in the income statement.

Retail, Energy Marketing and Other: Earnings from retail gasoline operations were higher in 2003 compared with 2002, reflecting increased margins and sales volumes. Retail gasoline operations in 2002 were profitable but less so than in 2001, reflecting lower margins. Energy marketing activities had increased earnings in 2003, reflecting increased margins and sales volumes in the early part of the year resulting from the cold winter. Energy marketing activities were profitable in 2002 compared with a loss in 2001. Results of the Port Reading refining facility improved in 2003 reflecting higher margins than in 2002. Total refined product sales volumes were 153 million barrels in 2003, 140 million barrels in 2002 and 141 million barrels in 2001.

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 $17 million in 2003, $3 million in 2002 and $45 million in 2001. Before income taxes, the trading income was $30 million in 2003, $6 million in 2002 and $72 million in 2001.

Refining and marketing earnings include the following items:

	After Income Taxes		
Millions of dollars	**2003**	2002	2001
Gain (loss) from asset sales	**$(20)**	$ 67	$ —
Reduction in carrying value of intangible assets	**—**	(14)	—
Severance accrual	**—**	(8)	(2)
	$(20)	$ 45	$ (2)

	Before Income Taxes		
Millions of dollars	**2003**	2002	2001
Gain (loss) from asset sales	**$(9)**	$102	$ —
Reduction in carrying value of intangible assets	**—**	(22)	—
Severance accrual	**—**	(13)	(3)
	$(9)	$ 67	$ (3)

In 2003, refining and marketing earnings include a net loss of $20 million (loss of $9 million before income taxes) from the sale of the Corporation's interest in a shipping joint venture.

In 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). In connection with this sale, the Corporation agreed to support the buyer's charter rate on these vessels for up to five years. The support agreement requires that if the actual contracted rate for the charter of a vessel is less than the stipulated support rate in the agreement the Corporation will pay to the buyer the difference between the contracted rate and the stipulated rate. At January 1, 2003, the charter support reserve was $48 million. During 2003, the Corporation paid $5 million of charter support. Based on contractual long-term charters entered into in 2003, and estimates of future charter rates, the Corporation lowered the estimated charter support reserve by $11 million. The balance in this reserve at December 31, 2003 was $32 million.

The Corporation 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 energy marketing.

Refining and marketing earnings will likely 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 $101 million in 2003, $63 million in 2002 and $78 million in 2001. The 2003 amount includes expenses of $34 million for premiums paid on the repurchase of bonds compared with $6 million in 2002. The pre-tax amounts of the bond repurchase premiums were $58 million in 2003 and $15 million in 2002 and are recorded in non-operating income (expense) in the income statement. Corporate administrative expenses, before income taxes, increased slightly in 2003 and were comparable in 2002 and 2001. The decrease in after-tax expenses in 2002 reflects lower United States taxes on foreign source income. After-tax corporate expenses for 2004 are estimated to be in the range of $60 to $70 million.

Interest: After-tax interest was $173 million in 2003, $165 million in 2002 and $135 million in 2001. The corresponding amounts before income taxes were $293 million, $256 million and $194 million in 2003, 2002 and 2001, respectively. Interest incurred in 2003 was lower than in 2002 because of debt reduction; however, the reduction in interest incurred was more than offset by lower capitalized interest in 2003. Capitalized interest in 2003, 2002 and 2001 was $41 million, $101 million and $44 million, respectively. Interest expense was higher in 2002 compared with 2001 reflecting increased borrowings related to acquisitions. After-tax interest expense in 2004 is anticipated to be approximately 20% below the 2003 level.

Discontinued Operations: 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 Block A-18 in the joint development area of Malaysia and Thailand (JDA). The exchange resulted in an after-tax charge to income of $47 million ($51 million before income taxes). The after-tax loss on this exchange included a $43 million adjustment of the book value of the Colombian assets to fair value. The loss also included $17 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 after-tax earnings in Colombia prior to the exchange of $13 million. The JDA production facilities are complete, but production will not commence until the purchasers of the gas complete the construction of a natural gas pipeline. The Corporation anticipates that production will begin in the second half of 2005.

In the second quarter of 2003, the Corporation sold Gulf of Mexico shelf properties, the Jabung Field in Indonesia and several small United Kingdom fields for $445 million. The after-tax gain from these asset sales of $175 million ($248 million before income taxes) was included in discontinued operations. Discontinued operations in 2003 also includes $40 million of income from operations prior to the sales of these assets.

Change in Accounting Principle: The Corporation adopted FAS No. 143, *Accounting for Asset Retirement Obligations,* effective January 1, 2003. A net after-tax gain of $7 million resulting from the cumulative effect of this accounting change was recorded at the beginning of the year. At the date of adoption, a liability of $556 million representing the estimated fair value of the Corporation's required dismantlement obligations was recorded on the balance sheet. In addition, a dismantlement asset of $311 million was recorded, as well as accumulated depreciation of $203 million.

Sales and Other Operating Revenues: In 2003, sales and other operating revenues increased by 24% compared with 2002. This increase principally reflects increased sales volumes and selling prices of refined products and the higher selling price of purchased natural gas in energy marketing activities. Sales and other operating revenues decreased by 12% in 2002 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. These decreases were partially offset by higher production of crude oil and natural gas. The change in cost of goods sold in each year reflects the change in sales of refined products and purchased natural gas.

Liquidity and Capital Resources

Overview: Cash flows from operating activities, including changes in operating assets and liabilities, totaled $1,581 million in 2003. During the year, the Corporation strengthened its financial position through sales of assets and the issuance of preferred stock. At December 31, 2003, the Corporation's debt to capitalization ratio was 42.5% compared to 54.0% at December 31, 2002. Total debt was $3,941 million at December 31, 2003 and $4,992 million at December 31, 2002. Cash and cash equivalents at the end of 2003 totaled $518 million, an increase of $321 million for the year. Long-term debt totaling $221 million matures over the next three years.

The Corporation has hedged the selling prices of a significant portion of its crude oil and natural gas production in 2004 and 2005 to help generate a level of cash flow that will meet operating and capital commitments.

Cash Flows from Operating Activities: Net cash provided by operating activities, including changes in operating assets and liabilities, totaled $1,581 million in 2003, $1,965 million in 2002 and $1,960 million in 2001. Lower cash flows in 2003 were primarily due to reduced exploration and production sales volumes.

Cash Flows from Investing Activities: The following table summarizes the Corporation's capital expenditures in 2003, 2002 and 2001:

Millions of dollars	**2003**	2002	2001
Exploration and production			
Exploration	**$ 196**	$ 239	$ 171
Production and development	**1,067**	1,095	1,250
Acquisitions	**23**	70	3,640
	1,286	1,404	5,061
Refining and marketing			
Operations	**72**	83	110
Acquisitions	**—**	47	50
	72	130	160
Total	**$1,358**	$1,534	$5,221

Capital expenditures in 2001 included $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. The amounts shown for acquisitions in 2002 principally represent final installment payments on prior year acquisitions.

In 2003, the Corporation took initiatives to reshape its portfolio of producing assets to reduce future costs, increase its reserve to production ratio, and provide capital for investment in new fields and funds to reduce debt. The Corporation sold certain producing properties in the Gulf of Mexico Shelf, the Jabung Field in Indonesia, several small United Kingdom fields and an interest in a shipping joint venture. Proceeds from asset sales totaled $545 million during 2003. In addition, the Corporation completed several asset exchanges. The Corporation swapped mature, high-cost assets in Colombia for an additional 25% interest in long-lived natural gas reserves in Block A-18 in the joint development area of Malaysia and Thailand, bringing the Corporation's interest in the area to 50%. The Corporation exchanged its 25% equity investment in Premier Oil plc for a 23% interest in Natuna Sea Block A in Indonesia, plus approximately $10 million in cash. In the fourth quarter of 2003, the Corporation exchanged 14% interests in the Scott and Telford fields in the United Kingdom for an additional 22.5% interest in the Llano Field in the Gulf of Mexico and $17 million in cash. This exchange increased the Corporation's working interest in the Llano Field to 50% and decreased its interest in the Scott Field to 21% and the Telford Field to 17%. Production from the Corporation's 50% interest in the Llano Field is scheduled to commence in mid-2004.

The net production from fields sold or exchanged at the time of disposition was approximately 50,000 barrels of oil equivalent per day. The Corporation believes the overall impact of its program of asset exchanges and sales of properties has not reduced its liquidity in the short-term or over the next five years.

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.

Cash Flows from Financing Activities: In the fourth quarter of 2003, the Corporation issued 13,500,000 shares of mandatory convertible preferred stock for net proceeds of $653 million. Cash flows from operations, asset sales and the issuance of preferred stock enabled the Corporation to reduce debt by $1,051 million during 2003. Debt repayment in 2002, net of new borrowings, was $673 million.

Future Capital Requirements and Resources: Capital expenditures in 2004 are expected to be approximately $1.5 billion. The Corporation anticipates that these expenditures will be funded by available cash and cash flow from operations. Lines of credit are available, if necessary. At December 31, 2003, the Corporation has an undrawn facility of $1.5 billion under its committed revolving credit agreement and has additional unused lines of credit of $206 million under uncommitted arrangements with banks. The Corporation's revolving credit agreement expires in 2006 and the Corporation expects it will be able to arrange a new committed facility at that time, if required. The Corporation also has a shelf registration under which it may issue $825 million of additional debt securities, warrants, common stock or preferred stock.

Loan agreement covenants allow the Corporation to borrow an additional $5 billion for the construction or acquisition of assets at December 31, 2003. At year end, the amount that can be borrowed under the loan agreements for the payment of dividends is $1.9 billion.

The Corporation's aggregate maturities of long-term debt total $221 million over the next three years. Based on current estimates of production, capital expenditures and other factors, and assuming West Texas Intermediate oil prices average $24 per barrel and United States natural gas prices average $4.25 per Mcf, the Corporation anticipates it will fund its future operations, including capital expenditures, dividends and required debt repayment, with existing cash on-hand, cash flow from operations and, when necessary, borrowings under its credit facilities and the issuance of securities under its shelf registration.

Prior to June 30, 1986, the Corporation had extensive exploration and production operations in Libya, however, it was required to suspend participation in these operations as a result of U.S. government sanctions. If U.S. sanctions on Libya are removed, and if the Corporation and its partners successfully negotiate with the government of Libya to resume participation in the group's former operations, management anticipates capital expenditures will likely increase over the current plan. Production and reserves would also increase. On February 24, 2004, the Corporation received U.S. Government authorization to negotiate and enter into an executory agreement with the government of Libya that would define the terms for resuming active participation in the Libyan properties. The Corporation's performance under this agreement will be contingent on obtaining future U.S. Government authorizations. The Corporation cannot predict the outcome or timing of these events.

Credit Ratings: While the Corporation maintains investment grade ratings from two rating agencies, one credit rating agency downgraded its rating of the Corporation's debt to non-investment grade in February 2004. Cash margin or collateral is required under certain contracts with hedging and trading counterparties and certain lenders. The amount of such cash margin or collateral would have increased at December 31, 2003 by approximately $230 million as a result of the downgrade. The downgrade is expected to increase annual pre-tax financing costs by less than $10 million.

Contractual Obligations and Contingencies: Following is a table showing aggregated information about certain contractual obligations at December 31, 2003:

		Payments Due by Period			
Millions of dollars	*Total*	*2004*	*2005 and 2006*	*2007 and 2008*	*Thereafter*
Long-term debt	$ 3,893	$ 63	$ 126	$ 327	$3,377
Capital leases	48	10	22	14	2
Operating leases	1,303	95	142	142	924
Purchase obligations					
Supply commitments	14,706	5,233	4,847	4,626	*
Capital expenditures	799	433	296	70	—
Operating expenses	266	170	44	31	21
Other long-term liabilities	235	110	56	32	37

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

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 at market prices 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 that are contractually committed at December 31. The Corporation's 2004 capital expenditures are estimated to be approximately $1.5 billion, including approximately $900 million for oil and gas developments. 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.

In connection with the sale of six vessels in 2002, the Corporation agreed to support the buyer's charter rate on these vessels for up to five years. The support agreement requires that if the actual contracted rate for the charter of a vessel is less than the stipulated support rate in the agreement, the Corporation will pay to the buyer the difference between the contracted rate and the stipulated rate. The balance in the charter support reserve at December 31, 2003 was $32 million.

The Corporation has a contingent purchase obligation to acquire the remaining 50% interest in a retail marketing and gasoline station joint venture for $88 million.

The Corporation guarantees the payment of up to 50% of HOVENSA's crude oil purchases from suppliers other than PDVSA. The amount of the Corporation's guarantee fluctuates based on the volume of crude oil purchased and related prices and at December 31, 2003 amounted to $134 million.

In addition, the Corporation has agreed to provide funding up to a maximum of $40 million to the extent HOVENSA does not have funds to meet its senior debt obligations.

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:

Millions of dollars	*Total*
Letters of credit	$ 7
Guarantees	92*
	$99

**Includes $40 million HOVENSA debt guarantee discussed above. The remainder relates principally to a loan guarantee for a natural gas pipeline in which the Corporation owns a 5% interest.*

Off-Balance Sheet Arrangements: The Corporation has leveraged lease financings not included in its balance sheet, primarily related to retail gasoline stations that the Corporation operates. The net present value of these financings is $462 million at December 31, 2003, using interest rates inherent in the leases. The Corporation's December 31, 2003 debt to capitalization ratio would increase from 42.5% to 45.2% if the lease financings were included.

See also *"Contractual Obligations and Contingencies"* above, Note No. 7, "Refining Joint Venture," and Note No. 18, "Guarantees and Contingencies," in the financial statements.

Foreign Operations: The Corporation conducts exploration and production activities in many foreign countries, including the United Kingdom, Norway, Denmark, Gabon, Indonesia, Thailand, Azerbaijan, Algeria, Malaysia 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 events 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 in the past been political disruptions in Venezuela that reduced the availability of Venezuelan crude oil used in refining operations, these disruptions did not have a material adverse effect on the Corporation's financial position. The Corporation also has a note receivable of $334 million at December 31, 2003 from a subsidiary of PDVSA. The Corporation anticipates collection of the remaining balance.

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 primarily 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. These controls apply to all of the Corporation's non-trading and trading activities, including the consolidated trading partnership. The Corporation's treasury department administers foreign exchange rate and interest rate hedging programs.

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 mainly with standardized terms. The following describes these instruments and how the Corporation uses them:

- *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 traded 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:* The Corporation uses financially settled swap contracts with third parties as part of its hedging and trading activities. Cash flows from swap contracts are determined based on underlying commodity prices and are typically settled 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 seller 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 the rate of interest 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 70% of its estimated 2004 worldwide crude oil production and 45% of its estimated 2005 worldwide crude oil production. The average price for West Texas Intermediate crude oil (WTI) related open hedge positions is $26.24 in 2004 and $25.83 in 2005. The average price for Brent crude oil related open hedge positions is $24.51 in 2004 and $24.41 in 2005. Approximately 18% of the Corporation's hedges are WTI related and the remainder are Brent. The Corporation also has hedged 30% of its 2004 United States natural gas production at an average price of $5.10 per Mcf. As market conditions change, the Corporation may adjust its hedge percentages.

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.

Millions of dollars	*Non-Trading Activities*
2003	
At December 31	**$44**
Average for the year	**43**
High during the year	**47**
Low during the year	**40**
2002	
At December 31	$50
Average for the year	49
High during the year	62
Low during the year	34

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, 2003, the Corporation has $384 million of notional value foreign exchange contracts maturing in 2004 and 2005 ($307 million at December 31, 2002). The fair value of foreign exchange contracts recorded as assets was $40 million at December 31, 2003 ($18 million at December 31, 2002). The change in fair value of the foreign exchange contracts from a 10% change in exchange rates is estimated to be $43 million at December 31, 2003 ($33 million at December 31, 2002).

At December 31, 2003, 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 $3,941 million has a fair value of $4,440 million at December 31, 2003 (debt of $4,992 million at December 31, 2002 had a fair value of $5,569 million). A 15% change in the rate of interest would change the fair value of debt at December 31, 2003 and 2002 by approximately $270 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.

Gains or losses from sales of physical products are recorded at the time of sale. Derivative trading transactions are marked-to-market and are reflected in income currently. Total realized gains for the year amounted to $50 million. The following table provides an assessment of the factors affecting the changes in fair value of trading activities and represents 100% of the trading partnership and other trading activities.

Millions of dollars	**2003**	2002
Fair value of contracts outstanding at the beginning of the year	**$ 36**	$(58)
Change in fair value of contracts outstanding at the beginning of the year and still outstanding at the end of year	**36**	(14)
Reversal of fair value for contracts closed during the year	**(26)**	75
Fair value of contracts entered into during the year and still outstanding	**21**	33
Fair value of contracts outstanding at the end of the year	**$ 67**	$ 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 regularly compares valuations to independent sources and models.

Millions of dollars	Total	2004	2005	2006
Source of fair value				
Prices actively quoted	$69	$33	$36	$—
Other external sources	5	(8)	7	6
Internal estimates	(7)	(4)	(3)	—
Total	$67	$21	$40	$ 6

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

Millions of dollars	*Trading Activities*
2003	
At December 31	**$ 7**
Average for the year	**9**
High during the year	**12**
Low during the year	**7**
2002	
At December 31	$ 6
Average for the year	10
High during the year	12
Low during the year	6

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

Millions of dollars	**2003**	2002
Investment grade determined by outside sources	**$246**	$309
Investment grade determined internally*	**89**	70
Less than investment grade	**16**	61
Not determined	**—**	2
	$351	$442

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

Critical Accounting Policies and Estimates

Accounting policies and estimates 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.

Accounting for Exploration and Development Costs: 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 based on estimates of proved reserves on a field basis.

The determination of estimated proved reserves is a significant element in arriving at the results of operations of exploration and production activities. The Corporation uses independent reservoir engineers to estimate all of its oil and gas reserves. The estimates of proved reserves 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.

Hedging: Hedging contracts correlate to the selling prices of crude oil or natural gas and the Corporation has designated these contracts as hedges. Therefore, the Corporation records gains or losses on these instruments in income in the period in which the production is sold. At December 31, 2003, the Corporation has $229 million of deferred hedging losses, after income taxes, included in other comprehensive income.

Impairment of Long-Lived Assets and Goodwill: 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 flow estimates, 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 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 the estimated timing of production on the Ceiba Field did not significantly affect the undiscounted future cash flows, but did significantly reduce the fair value of the field determined by discounted cash flows. The Corporation could have additional impairments if the projected production volumes from 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, has aggregated 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 estimates 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.

Because there are significant differences in the way long-lived assets and goodwill are evaluated and measured for impairment testing, 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 existed because the fair value of the overall exploration and production operating segment continued to exceed its recorded book value.

Segments: 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 such 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.

Oil and Gas Mineral Rights: 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 $2.3 billion at December 31, 2003 and $2.2 billion at December 31, 2002, 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. If mineral rights are reclassified to intangible assets, FAS No. 142, *Goodwill and Other Intangible Assets,* will require additional disclosures in the financial statement notes. This potential balance sheet reclassification would not affect results of operations or cash flows.

Environment, Health and Safety

The Corporation has implemented a values-based, social-responsibility strategy focused on improved environment, health, and safety performance and making a positive impact on communities and the environment. The strategy is supported by the Corporation's environment, health, safety and social responsibility policies and management systems that help protect the Corporation's workforce, customers and local communities. Overall governance is the responsibility of senior management. To ensure that the Corporation meets its goals and regulatory requirements, the Corporation has programs in place 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 may raise the Corporation's operating costs and require 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 likely 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 substantially reduce 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. The estimated capital expenditures necessary to comply with the low-sulfur gasoline requirements at Port Reading are approximately $70 million over the next several 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 three 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 and New York (effective January 2004), and other states are considering them. If Congress bans MTBE or if additional 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 various options to market and produce reformulated gasolines if additional MTBE bans take effect.

In 2003, the Corporation and HOVENSA began discussions with the U.S. EPA regarding the EPA's Petroleum Refining Initiative (PRI). The PRI is an ongoing program that is designed to reduce certain air emissions at all U.S. refineries. Presently over 40% of U.S. refining capacity is operating under PRI controls and an additional 37% of refining capacity will be included in early 2004. Depending on the outcome of these discussions, which will not likely be concluded until 2005, the Corporation and HOVENSA may experience increased capital and operating expenses related to air emissions controls. The PRI allows for controls to be phased in over several years.

The Corporation recognizes the worldwide concern about the environmental impact of air emissions. On a global scale, climate change is an issue that has prompted much public debate and has a potential impact on future growth and development. The Corporation has undertaken a program to assess, monitor and reduce the emission of "greenhouse gases," including carbon dioxide and methane. The challenges associated with this program may be significant, not only from the standpoint of technical feasibility, but also from the perspective of adequately measuring the Corporation's entire greenhouse gas inventory. The Corporation is working to establish an internal greenhouse gas reporting protocol that will provide a common set of principles and guidelines for reporting data from operated facilities and from assets operated by the Corporation's partners.

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 accrues for environmental expenses when the future costs are probable and reasonably estimable. At year end 2003, the Corporation's reserve for its estimated environmental liability was approximately $85 million. Remediation spending was $12 million in 2003, $9 million in 2002, and $8 million in 2001. Capital expenditures for facilities, primarily to comply with federal, state and local environmental standards, were $7 million in 2003, $5 million in 2002, and $6 million in 2001. The Corporation expects that existing reserves for environmental liabilities will adequately cover costs to assess and remediate known sites.

Dividends

Cash dividends on common stock totaled $1.20 per share ($.30 per quarter) during 2003 and 2002. Dividends on the 7% cumulative mandatory convertible preferred stock will total $3.50 per share ($.875 per quarter).

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 2003 and 2002 were as follows:

	2003		2002	
Quarter Ended	*High*	*Low*	*High*	*Low*
March 31	**$57.20**	**$41.14**	$80.15	$57.60
June 30	**51.50**	**43.51**	84.70	74.61
September 30	**50.90**	**45.04**	83.00	61.36
December 31	**55.25**	**46.09**	71.48	49.40

The high and low sales prices of the Corporation's 7% cumulative mandatory convertible preferred stock (traded on the New York Stock Exchange, ticker symbol: AHCPR) since issuance in the fourth quarter of 2003 to December 31 were $55.43 and $49.50, respectively.

Quarterly Financial Data

Quarterly results of operations for the years ended December 31, 2003 and 2002 follow:

Millions of dollars, except per share data	Sales and other operating revenues	Gross profit (a)	Net income (loss)(b)	Net income (loss) per share
2003				
First	**$4,254**	**$477**	**$ 177**[c]	**$ 1.98**
Second	**3,199**	**382**	**252**[d]	**2.83**
Third	**3,230**	**361**	**146**[e]	**1.64**
Fourth	**3,628**	**394**	**68**[d][f]	**.71**
2002				
First	$2,926	$368	$ 140[g]	$ 1.58
Second	2,694	385	149[h]	1.66
Third	2,724	419	(136)[i]	(1.54)
Fourth	3,207	431	(371)[j]	(4.20)

(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) Includes net income (loss) from discontinued operations, as follows:

Quarter	2003	2002
First	$ (20)	$ 9
Second	189	20
Third	—	(31)
Fourth	—	29

(c) Includes income of $7 million from the cumulative effect of the adoption of FAS No. 143, Accounting for Asset Retirement Obligations. *Also includes income of $31 million ($47 million before income taxes) from asset sales.*

(d) Includes after-tax charges of $23 million ($38 million before income taxes) in the second quarter and $9 million ($15 million before income taxes) in the fourth quarter for accrued severance and a reduction in leased office space in London. Also includes a net loss in the second quarter of $20 million ($9 million before income taxes) from the sale of a shipping joint venture.

(e) Includes a U.S. income tax benefit of $30 million for the recognition of certain prior year foreign exploration expenses.

(f) Includes $19 million after-tax ($31 million before income taxes) for premiums paid on repurchase of bonds.

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

(h) 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.

(i) 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.

(j) 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.

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

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, market risk and environmental disclosures, off-balance sheet arrangements and contractual obligations and contingencies include 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.

CONSOLIDATED BALANCE SHEET

Amerada Hess Corporation and Consolidated Subsidiaries

Millions of dollars; thousands of shares	*At December 31* **2003**	2002
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 518**	$ 197
Accounts receivable		
Trade	**1,717**	1,785
Other	**185**	187
Inventories	**579**	492
Other current assets	**187**	95
Total current assets	**3,186**	2,756
INVESTMENTS AND ADVANCES		
HOVENSA L.L.C.	**960**	842
Other	**135**	780
Total investments and advances	**1,095**	1,622
PROPERTY, PLANT AND EQUIPMENT		
Exploration and production	**14,614**	14,699
Refining and marketing	**1,486**	1,450
Total—at cost	**16,100**	16,149
Less reserves for depreciation, depletion, amortization and lease impairment	**8,122**	9,117
Property, plant and equipment—net	**7,978**	7,032
NOTES RECEIVABLE	**302**	363
GOODWILL	**977**	977
DEFERRED INCOME TAXES AND OTHER ASSETS	**445**	512
TOTAL ASSETS	**$13,983**	$13,262

	At December 31	
	2003	2002
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable—trade	**$ 1,542**	$ 1,401
Accrued liabilities	**855**	830
Taxes payable	**199**	306
Notes payable	**—**	2
Current maturities of long-term debt	**73**	14
Total current liabilities	**2,669**	2,553
LONG-TERM DEBT	**3,868**	4,976
DEFERRED LIABILITIES AND CREDITS		
Deferred income taxes	**1,144**	1,044
Asset retirement obligations	**462**	—
Other	**500**	440
Total deferred liabilities and credits	**2,106**	1,484
STOCKHOLDERS' EQUITY		
Preferred stock, par value $1.00, 20,000 shares authorized		
7% cumulative mandatory convertible series		
Authorized—13,500 shares		
Issued—13,500 shares in 2003 ($675 liquidation preference)	**14**	—
3% cumulative convertible series		
Authorized—330 shares		
Issued—327 shares in 2003 and 2002 ($16 liquidation preference)	**—**	—
Common stock, par value $1.00		
Authorized—200,000 shares		
Issued—89,868 shares in 2003; 89,193 shares in 2002	**90**	89
Capital in excess of par value	**1,603**	932
Retained earnings	**4,011**	3,482
Accumulated other comprehensive income (loss)	**(350)**	(254)
Deferred compensation	**(28)**	—
Total stockholders' equity	**5,340**	4,249
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$13,983**	$13,262

The consolidated financial statements reflect the successful efforts method of accounting for oil and gas exploration and production activities.
See accompanying notes to consolidated financial statements.

STATEMENT OF CONSOLIDATED INCOME

Amerada Hess Corporation and Consolidated Subsidiaries

	For the Years Ended December 31		
Millions of dollars, except per share data	**2003**	2002	2001
REVENUES AND NON-OPERATING INCOME			
Sales (excluding excise taxes) and other operating revenues	**$14,311**	$11,551	$13,052
Non-operating income (expense)			
Gain on asset sales	**39**	143	—
Equity in income (loss) of HOVENSA L.L.C.	**117**	(47)	58
Other	**13**	85	150
Total revenues and non-operating income	**14,480**	11,732	13,260
COSTS AND EXPENSES			
Cost of products sold	**9,947**	7,226	8,739
Production expenses	**796**	736	642
Marketing expenses	**709**	703	663
Exploration expenses, including dry holes and lease impairment	**369**	316	347
Other operating expenses	**192**	165	213
General and administrative expenses	**340**	253	311
Interest expense	**293**	256	194
Depreciation, depletion and amortization	**1,053**	1,118	833
Asset impairments	**—**	1,024	—
Total costs and expenses	**13,699**	11,797	11,942
Income (loss) from continuing operations before income taxes	**781**	(65)	1,318
Provision for income taxes	**314**	180	502
Income (loss) from continuing operations	**467**	(245)	816
Discontinued operations			
Net gain from asset sales	**116**	—	—
Income from operations	**53**	27	98
Cumulative effect of change in accounting principle	**7**	—	—
NET INCOME (LOSS)	**$ 643**	$ (218)	$ 914
Less preferred stock dividends	**5**	—	—
NET INCOME (LOSS) APPLICABLE TO COMMON SHAREHOLDERS	**$ 638**	$ (218)	$ 914
BASIC EARNINGS (LOSS) PER SHARE			
Continuing operations	**$ 5.21**	$ (2.78)	$ 9.26
Net income (loss)	**7.19**	(2.48)	10.38
DILUTED EARNINGS (LOSS) PER SHARE			
Continuing operations	**$ 5.17**	$ (2.78)	$ 9.15
Net income (loss)	**7.11**	(2.48)	10.25

See accompanying notes to consolidated financial statements.

STATEMENT OF CONSOLIDATED RETAINED EARNINGS

Amerada Hess Corporation and Consolidated Subsidiaries

	For the Years Ended December 31		
Millions of dollars, except per share data	**2003**	2002	2001
BALANCE AT BEGINNING OF YEAR	**$3,482**	$3,807	$3,069
Net income (loss)	**643**	(218)	914
Dividends declared—common stock			
($1.20 per share in 2003, 2002 and 2001)	**(109)**	(107)	(107)
Dividends on preferred stock ($.34 per share in 2003)	**(5)**	—	—
Common stock acquired and retired	**—**	—	(69)
BALANCE AT END OF YEAR	**$4,011**	$3,482	$3,807

See accompanying notes to consolidated financial statements.

STATEMENT OF CONSOLIDATED CASH FLOWS

Amerada Hess Corporation and Consolidated Subsidiaries

	For the Years Ended December 31		
Millions of dollars	**2003**	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	**$ 643**	$ (218)	$ 914
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	**1,053**	1,118	833
Asset impairments	**—**	1,024	—
Exploratory dry hole costs	**162**	157	185
Lease impairment	**65**	41	38
Pre-tax gain on asset sales	**(245)**	(117)	—
Provision (benefit) for deferred income taxes	**107**	(258)	64
Undistributed earnings of affiliates	**(130)**	47	(52)
Non-cash effect of discontinued operations	**46**	280	153
Changes in other operating assets and liabilities			
(Increase) decrease in accounts receivable	**47**	(104)	650
(Increase) decrease in inventories	**(107)**	51	(131)
Increase (decrease) in accounts payable and accrued liabilities	**18**	(217)	(553)
Increase (decrease) in taxes payable	**(39)**	50	(185)
Changes in prepaid expenses and other	**(39)**	111	44
Net cash provided by operating activities	**1,581**	1,965	1,960
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures			
Exploration and production	**(1,286)**	(1,404)	(2,341)
Refining and marketing	**(72)**	(130)	(160)
Total capital expenditures	**(1,358)**	(1,534)	(2,501)
Acquisition of Triton Energy Limited, net of cash acquired	**—**	—	(2,720)
Proceeds from asset sales	**545**	412	67
Payment received on note receivable	**61**	48	48
Other	**(25)**	(22)	(99)
Net cash used in investing activities	**(777)**	(1,096)	(5,205)
CASH FLOWS FROM FINANCING ACTIVITIES			
Debt with maturities of 90 days or less – increase (decrease)	**(2)**	(581)	564
Debt with maturities of greater than 90 days			
Borrowings	**—**	637	2,595
Repayments	**(1,026)**	(686)	(54)
Proceeds from issuance of preferred stock	**653**	—	—
Cash dividends paid	**(108)**	(107)	(94)
Common stock and warrants acquired	**—**	—	(100)
Stock options exercised	**—**	28	59
Net cash provided by (used in) financing activities	**(483)**	(709)	2,970
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**321**	160	(275)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**197**	37	312
CASH AND CASH EQUIVALENTS AT END OF YEAR	**$ 518**	$ 197	$ 37

See accompanying notes to consolidated financial statements.

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

Amerada Hess Corporation and Consolidated Subsidiaries

	Preferred Stock		Common Stock		
Millions of dollars; thousands of shares	*Number of shares*	*Amount*	*Number of shares*	*Amount*	*Capital in excess of par value*
BALANCE AT JANUARY 1, 2001	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
Issuance of preferred stock	13,500	14	—	—	639
Distributions to trustee of nonvested common stock awards (net)	—	—	675	1	32
BALANCE AT DECEMBER 31, 2003	**13,827**	**$14**	**89,868**	**$90**	**$1,603**

STATEMENT OF CONSOLIDATED COMPREHENSIVE INCOME

	For the Years Ended December 31		
Millions of dollars	**2003**	2002	2001
COMPONENTS OF COMPREHENSIVE INCOME (LOSS)			
Net income (loss)	**$643**	$(218)	$ 914
Change in foreign currency translation adjustment	**13**	34	(2)
Additional minimum pension liability, after tax	**(1)**	(71)	—
Deferred gains (losses) on oil and gas cash flow hedges, after tax			
FAS 133 transition adjustment	**—**	—	100
Reclassification of deferred hedging to income	**203**	(56)	(74)
Net change in fair value of cash flow hedges	**(311)**	(269)	223
COMPREHENSIVE INCOME (LOSS)	**$547**	$(580)	$1,161

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Amerada Hess Corporation and Consolidated Subsidiaries

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, Equatorial Guinea and Algeria. The Corporation also has oil and gas activities in Azerbaijan, 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, depreciable lives, pension liabilities, environmental obligations, dismantlement costs and income taxes.

Certain information in the financial statements and notes has been reclassified to conform with current period presentation.

Principles of Consolidation: The consolidated financial statements include the accounts of Amerada Hess Corporation and entities in which the Corporation owns more than a 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 average 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 expensed 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.

Asset Retirement Obligations: The Corporation recognizes a liability for the fair value of legally required asset retirement obligations associated with long-lived assets in the period in which the retirement obligations are incurred. The Corporation capitalizes the associated asset retirement costs as part of the carrying amount of the long-lived assets.

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 fair value of goodwill is less than the carrying amount, an impairment would be 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 (Restricted 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 following pro forma financial information presents the effect on net income and earnings per share as if the Corporation used the fair value method. The Corporation records compensation expense for non-vested common stock awards ratably over the vesting period.

Millions of dollars, except per share data	**2003**	2002	2001
Net income (loss)	**$ 643**	$ (218)	$ 914
Add stock-based employee compensation expense included in net income, net of taxes	**7**	5	8
Less total stock-based employee compensation expense determined using the fair value method, net of taxes	**(8)**	(19)	(22)
Pro forma net income (loss)	**$ 642**	$ (232)	$ 900
Net income (loss) per share as reported			
Basic	**$7.19**	$(2.48)	$10.38
Diluted	**7.11**	(2.48)	10.25
Pro forma net income (loss) per share			
Basic	**$7.19**	$(2.63)	$10.23
Diluted	**7.11**	(2.63)	10.10

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 selling prices. The Corporation also uses derivatives in its energy marketing activities to fix the purchase prices of commodities to be sold under fixed-price contracts. 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 changes in fair value 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 (futures, forwards, options and swaps) used in energy trading activities are marked to market, with net gains and losses recorded in operating revenue. Gains or losses from the sale of physical products are recorded at the time of sale.

2. ITEMS AFFECTING INCOME FROM CONTINUING OPERATIONS

2003: The Corporation recorded a pre-tax charge of $58 million for premiums paid on the repurchase of bonds. This amount included premiums on bonds repurchased with proceeds of the fourth quarter preferred stock offering. The repurchased bonds included notes due in 2005 and 2007 assumed from Triton Energy at the time of the acquisition. This charge is reflected in non-operating income (expense) in the income statement.

The Corporation recorded expense of $53 million, before income taxes, for accrued severance and London office lease costs in exploration and production operations. Of this amount, $32 million relates to leased office space and the remainder relates to severance for positions that were eliminated in London, Aberdeen and Houston. Over 700 employee and contractor positions have been or will be eliminated or transferred to other operators. Approximately 240 employees are receiving severance, $15 million of which has been paid. The remainder is expected to be paid in 2004. The estimated annual savings from this cost reduction initiative is approximately $50 million before income taxes. The Corporation anticipates realizing approximately sixty percent of the savings in 2004 and the full amount in 2005 and beyond. The 2003 expense is reflected principally in general and administrative expense in the income statement.

Exploration and production earnings in 2003 include income tax benefits of $30 million reflecting the recognition of certain prior year foreign exploration expenses for United States income tax purposes. In addition, the Corporation recorded a pre-tax gain of $47 million from the sale of its 1.5% interest in the Trans-Alaska Pipeline System. A pre-tax loss of $9 million was recorded in refining and marketing earnings as a result of the sale of a shipping joint venture. Gains and losses on asset sales are reflected in non-operating income (expense) in the income statement.

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 flows were 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 was 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 pays 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. At January 1, 2003, the charter support reserve was $48 million. During 2003, the Corporation paid $5 million of charter support. Based on contractual long-term charter rates and estimates of future charter rates, the Corporation lowered the estimated charter support reserve by $11 million. While the Corporation's eventual obligations under the support agreement could exceed the amount of the deferred gain, based on current estimates, the remaining amount recorded at December 31, 2003, $32 million, is appropriate.

Pre-tax net gains of $41 million were 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 2002 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. The accrued severance was paid prior to December 31, 2003.

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.

The Corporation recorded a pre-tax charge of $18 million for severance expenses resulting from cost reduction initiatives, all of which has been paid. 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.

3. DISCONTINUED OPERATIONS

In 2003, the Corporation took initiatives to reshape its portfolio of exploration and production assets to reduce costs, lengthen reserve lives, provide capital for investment and 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 a $26 million charge 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 of $18 million in Colombia prior to the exchange.

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 has consolidated 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 $97 million in 2003, $381 million in 2002 and $361 million in 2001. Pretax operating profit for the same periods was $82 million, $14 million and $120 million, respectively. Income tax expense (benefit) was $29 million, $(13) million and $22 million for the same periods. The net production from fields accounted for as discontinued operations in 2003 at the time of disposition was approximately 45,000 barrels of oil equivalent per day.

4. ACCOUNTING CHANGE

On January 1, 2003, the Corporation changed its method of accounting for asset retirement obligations as required by FAS No. 143, *Accounting for Asset Retirement Obligations.* Previously, the Corporation had accrued the estimated costs of dismantlement, restoration and abandonment, less estimated salvage values, of offshore oil and gas production platforms and pipelines using the units-of-production method. This cost was reported as a component of depreciation expense and accumulated depreciation. Using the new accounting method required by FAS No. 143, the Corporation now recognizes a liability for the fair value of legally required asset retirement obligations associated with long-lived assets in the period in which the retirement obligations are incurred. The Corporation capitalizes the associated asset retirement costs as part of the carrying amount of the long-lived assets.

The cumulative effect of this change on prior years resulted in a credit to income of $7 million or $.07 per share, basic and diluted. The cumulative effect is included in income for the year ended December 31, 2003. The effect of the change on the year 2003 was to increase income before the cumulative effect of the accounting change by $3 million, after-tax ($.03 per share diluted). Assuming the accounting change had been applied retroactively to January 1, 2001 (rather than January 1, 2003), there would not have been a material change in income from continuing operations and net income in 2002 and 2001.

The following table describes changes to the Corporation's asset retirement obligations:

Millions of dollars	**2003**
Asset retirement obligations at January 1	**$ 556**
Liabilities incurred	**15**
Liabilities settled or disposed of	**(173)**
Accretion expense	**28**
Revisions	**25**
Foreign currency translation	**11**
Asset retirement obligations at December 31	**$ 462**

If FAS No. 143 had been applied beginning January 1, 2002 (rather than at January 1, 2003), the pro forma liability for asset retirement obligations at that date would have been $537 million.

The Corporation has adopted Emerging Issues Task Force abstract 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 with changes reflected in income currently. Beginning January 1, 2003, the Corporation accounted for all trading inventory at the lower of cost or market. This accounting change did not have a material effect on 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 $2.3 billion at December 31, 2003, and $2.2 billion at December 31, 2002, 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. If mineral rights are reclassified to intangible assets, FAS No. 142, *Goodwill and Other Intangible Assets,* will require additional disclosures in the financial statement footnotes. This potential balance sheet reclassification would not affect results of operations or cash flows.

5. 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 purchase price resulted in the recognition of goodwill of $977 million. 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 goodwill is assigned to the exploration and production reporting unit and is not deductible for income tax purposes.

The following 2001 pro forma results of operations present information as if the Triton acquisition occurred at the beginning of 2001:

Millions of dollars, except per share data	
Pro forma revenue	$13,936
Pro forma income	$ 914
Pro forma earnings per share	
Basic	$ 10.38
Diluted	$ 10.25

6. INVENTORIES

Inventories at December 31 are as follows:

Millions of dollars	**2003**	2002
Crude oil and other charge stocks	**$ 138**	$ 99
Refined and other finished products	**567**	497
Less: LIFO adjustment	**(293)**	(261)
	412	335
Materials and supplies	**167**	157
Total	**$ 579**	$ 492

7. 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, 2003, 2002 and 2001 and for the years then ended follows:

Millions of dollars	**2003**	2002	2001
Summarized Balance Sheet			
At December 31			
Cash and cash equivalents	**$ 341**	$ 11	$ 25
Other current assets	**541**	509	466
Net fixed assets	**1,818**	1,895	1,846
Other assets	**37**	40	35
Current liabilities	**(441)**	(335)	(294)
Long-term debt	**(392)**	(467)	(365)
Deferred liabilities and credits	**(56)**	(45)	(23)
Partners' equity	**$1,848**	$ 1,608	$ 1,690
Summarized Income Statement			
For the years ended December 31			
Total revenues	**$5,451**	$ 3,783	$ 4,209
Costs and expenses	**(5,212)**	(3,872)	(4,089)
Net income (loss)*	**$ 239**	$ (89)	$ 120

**The Corporation's share of HOVENSA's income was $117 million in 2003 and $58 million in 2001. The Corporation's share of the 2002 loss was $47 million. The Corporation's share of HOVENSA's undistributed income aggregated $240 million at December 31, 2003.*

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 $2,040 million during 2003, $1,280 million during 2002 and $1,500 million during 2001. The Corporation sold crude oil to HOVENSA for approximately $410 million during 2003, $80 million during 2002 and $110 million during 2001. In addition, the Corporation billed HOVENSA freight charter costs of $59 million during 2003, $20 million during 2002 and $55 million during 2001.

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, 2003, this amount was $134 million. This amount fluctuates based on the volume of crude oil purchased and the related crude oil prices. In addition, the Corporation has agreed to provide funding to the extent HOVENSA does not have funds to meet its senior debt obligations up to a maximum of $40 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, 2003 and December 31, 2002, the principal balance of the note was $334 million and $395 million, respectively.

8. PROPERTY, PLANT AND EQUIPMENT

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

Millions of dollars	**2003**	2002
Exploration and production		
Unproved properties	**$ 950**	$ 1,020
Proved properties	**2,634**	2,843
Wells, equipment and related facilities	**11,030**	10,836
Refining and marketing	**1,486**	1,450
Total — at cost	**16,100**	16,149
Less reserves for depreciation, depletion, amortization and lease impairment	**8,122**	9,117
Property, plant and equipment, net	**$ 7,978**	$ 7,032

During 2003, the Corporation recorded non-cash additions to fixed assets of $1,340 million. Of this total, $485 million related to assets that were previously accounted for as an equity investment in a company that holds natural gas reserves in Malaysia and Thailand. The remaining $855 million resulted from asset exchanges. The Corporation also recorded deferred income tax liabilities of $105 million related to the asset exchanges. The assets and liabilities relinquished in these exchanges included fixed assets of approximately $770 million, an additional equity investment of $145 million and deferred income tax liabilities of $145 million.

9. SHORT-TERM NOTES AND RELATED LINES OF CREDIT

The Corporation has no short-term notes at December 31, 2003. Short-term notes payable to banks at December 31, 2002 amounted to $2 million, bearing interest at a weighted average rate of 1.4%. At December 31, 2003, the Corporation has uncommitted arrangements with banks for unused lines of credit aggregating $206 million.

10. LONG-TERM DEBT

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

Millions of dollars	**2003**	2002
Fixed rate debentures, weighted average rate 7.2%, due through 2033	**$3,222**	$4,237
Pollution Control Revenue Bonds, weighted average rate 6.5%, due through 2032	**53**	53
Fixed rate notes, payable principally to insurance companies, weighted average rate 8.4%, due through 2014	**450**	450
Project lease financing, weighted average rate 5.1%, due through 2014	**164**	169
Capitalized lease obligations, weighted average rate 6.4%, due through 2009	**48**	56
6.1% Marine Terminal Revenue Bonds—Series 1994—City of Valdez, Alaska	**—**	20
Other loans, weighted average rate 9.3%, due through 2019	**4**	5
	3,941	4,990
Less amount included in current maturities	**73**	14
Total	**$3,868**	$4,976

The aggregate long-term debt maturing during the next five years is as follows (in millions): 2004—$73 (included in current liabilities); 2005—$60; 2006—$88; 2007—$212 and 2008—$129.

The Corporation's long-term debt agreements contain restrictions on the amount of total borrowings and cash dividends allowed. At December 31, 2003, the Corporation is permitted to borrow an additional $5 billion for the construction or acquisition of assets. At year-end, the amount that can be borrowed for the payment of dividends is $1.9 billion.

During 2003, the Corporation repurchased $1,015 million of fixed rate debentures consisting of most of the Corporation's 5.3% and 5.9% notes due in 2004 and 2006, respectively, as well as notes due in 2005 and 2007 assumed from Triton at the time of the acquisition. At December 31, 2003, the Corporation's public fixed rate debentures have a face value of $3,237 million ($3,222 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 7.2%.

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 were assumed by the purchaser.

The Corporation has a $1.5 billion revolving credit agreement, which was unutilized at December 31, 2003 and expires in January 2006. Because of a credit downgrade in February 2004, borrowings under the facility currently would bear interest at 1.125% above the London Interbank Offered Rate. A facility fee of .375% per annum is currently payable on the amount of the credit line. At December 31, 2003, the interest rate was .725% above the London Interbank Offered Rate and the facility fee was .15%.

In 2003, 2002 and 2001, the Corporation capitalized interest of $41 million, $101 million and $44 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 2003, 2002 and 2001 was $313 million, $274 million and $121 million, respectively.

11. STOCK BASED COMPENSATION PLANS

The Corporation has outstanding stock options and nonvested common stock (restricted 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. Outstanding nonvested common stock generally vests five years from the date of grant.

The Corporation's stock option activity in 2003, 2002 and 2001 consisted of the following:

	Options (thousands)	*Weighted-average exercise price per share*
Outstanding at January 1, 2001	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**
Granted	**65**	**47.07**
Forfeited	**(283)**	**64.08**
Outstanding at December 31, 2003	**4,157**	**$58.54**
Exercisable at December 31, 2001	3,216	$57.85
Exercisable at December 31, 2002	4,329	58.99
Exercisable at December 31, 2003	**4,092**	**58.72**

Exercise prices for employee stock options at December 31, 2003 ranged from $45.76 to $84.61 per share. The weighted-average remaining contractual life of employee stock options is 6 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 2003, 2002 and 2001, respectively: risk-free interest rates of 3.6%, 4.2% and 4.1%; expected stock price volatility of .288, .262 and .244; dividend yield of 2.6%, 1.9% and 2.0%; and an expected life of seven years. The Corporation's net income would have been reduced by approximately $1 million in 2003 and $14 million in 2002 and 2001 if option expenses were recorded using the fair value method.

The weighted-average fair value per share of options granted for which the exercise price equaled the market price on the date of grant were $12.60 in 2003, $19.63 in 2002 and $16.20 in 2001.

Total compensation expense for nonvested common stock was $11 million in 2003, $7 million in 2002 and $12 million in 2001. Awards of nonvested common stock were as follows:

	Shares of nonvested common stock awarded (thousands)	*Weighted-average price on date of grant*
Granted in 2001	108	$67.25
Granted in 2002	21	66.29
Granted in 2003	**765**	**46.73**

At December 31, 2003, the number of common shares reserved for issuance under the 1995 Long-Term Incentive Plan is as follows (in thousands):

Future awards	479
Stock options outstanding	4,157
Stock appreciation rights	4
Total	4,640

12. FOREIGN CURRENCY TRANSLATION

Foreign currency gains (losses) from continuing operations before income taxes amounted to $(6) million in 2003, $26 million in 2002 and $(22) million in 2001.

The balances in accumulated other comprehensive income related to foreign currency translation were reductions in stockholders' equity of $94 million at December 31, 2003 and $107 million at December 31, 2002.

13. PENSION PLANS

The Corporation has funded noncontributory defined benefit pension plans for substantially all of its employees. In addition, the Corporation has an unfunded supplemental pension plan covering certain employees. The unfunded 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 plans, were it not for limitations imposed by income tax regulations. The plans provide defined benefits based on years of service and final average salary. The Corporation uses December 31 as the measurement date for its plans.

The following table reconciles the projected benefit obligation and the fair value of plan assets and shows the funded status of the pension plans:

	Funded Pension Benefits		*Unfunded Pension Benefits*	
Millions of dollars	**2003**	2002	**2003**	2002
Reconciliation of projected benefit obligation				
Balance at January 1	**$ 721**	$ 623	**$ 61**	$ 59
Service cost	**24**	23	**3**	2
Interest cost	**47**	44	**4**	4
Amendments	**—**	—	**—**	4
Actuarial loss	**57**	60	**3**	1
Benefit payments	**(32)**	(29)	**(6)**	(9)
Balance at December 31	**817**	721	**65**	61
Reconciliation of fair value of plan assets				
Balance at January 1	**487**	495	**—**	—
Actual return on plan assets	**104**	(42)	**—**	—
Employer contributions	**67**	63	**6**	9
Benefit payments	**(32)**	(29)	**(6)**	(9)
Balance at December 31	**626**	487	**—**	—
Funded status (plan assets less than benefit obligations)	**(191)**	(234)	**(65)***	(61)*
Unrecognized net actuarial loss	**190**	214	**18**	15
Unrecognized prior service cost	**3**	5	**3**	3
Net amount recognized	**$ 2**	$ (15)	**$(44)**	$(43)

**The trust established by the Corporation to fund the supplemental plan held assets valued at $40 million at December 31, 2003 and $26 million at December 31, 2002.*

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

	Funded Pension Benefits		*Unfunded Pension Benefits*	
Millions of dollars	**2003**	2002	**2003**	2002
Accrued benefit liability	**$(106)**	$(130)	**$(53)**	$(44)
Intangible assets	**3**	5	**3**	1
Accumulated other comprehensive income*	**105**	110	**6**	—
Net amount recognized	**$ 2**	$ (15)	**$(44)**	$(43)

**Amount included in other comprehensive income after income taxes was $73 million at December 31, 2003 and $72 million at December 31, 2002.*

The accumulated benefit obligation for the funded defined benefit pension plans was $733 million at December 31, 2003 and $639 million at December 31, 2002. The accumulated benefit obligation for the unfunded defined benefit pension plan was $53 million at December 31, 2003 and $44 million at December 31, 2002.

All pension plans had accumulated benefit obligations in excess of plan assets at December 31, 2003 and 2002.

Components of funded and unfunded pension expense consisted of the following:

Millions of dollars	**2003**	2002	2001
Service cost	**$ 27**	$ 25	$ 21
Interest cost	**51**	49	45
Expected return on plan assets	**(44)**	(44)	(48)
Amortization of prior service cost	**2**	2	3
Amortization of net loss	**19**	5	1
Net periodic benefit cost	**$ 55**	$ 37	$ 22
Increase in minimum liability included in other comprehensive income	**$ 1**	$110	$ —

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 funded and unfunded pension plans were as follows:

	2003	2002	2001
Weighted-average assumptions used to determine benefit obligations at December 31			
Discount rate	**6.2%**	6.6%	7.0%
Rate of compensation increase	**4.5**	4.4	4.5
Weighted-average assumptions used to determine net cost for years ended December 31			
Discount rate	**6.6%**	7.0%	7.0%
Expected return on plan assets	**8.5**	9.0	9.0
Rate of compensation increase	**4.4**	4.5	4.5

The assumed long-term rate of return on assets is based on historical, long-term returns of the plan, adjusted downward to reflect lower prevailing interest rates. The assumed long-term rate of return is less than the actual return for the year ended December 31, 2003.

The Corporation's funded pension plan assets by asset category are as follows:

	At December 31	
Asset Category	**2003**	2002
Equity securities	**57%**	57%
Debt securities	**43**	43
Total	**100%**	100%

The target investment allocations for the plan assets are 55% equity securities and 45% debt securities. Asset allocations are rebalanced on a regular basis throughout the year to bring assets to within a 2—3% range of target levels. Target allocations take into account analyses performed to optimize long term risk and return relationships. All assets are highly liquid and can be readily adjusted to provide liquidity for current benefit payment requirements.

The Corporation has budgeted contributions of $82 million to its funded pension plans in 2004. The Corporation also has budgeted contributions of $20 million to the trust established for the unfunded plan.

Estimated future pension benefit payments for the funded and unfunded plans, which reflect expected future service, are as follows:

Millions of dollars	
2004	$ 43
2005	38
2006	39
2007	41
2008	43
Years 2009 to 2013	258

14. PROVISION FOR INCOME TAXES

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

Millions of dollars	**2003**	2002	2001
United States Federal			
Current	**$(180)**	$ 30	$ 57
Deferred	**78**	(158)	50
State	**(13)**	5	27
	(115)	(123)	134
Foreign			
Current	**431**	401	355
Deferred	**(2)**	(141)	13
	429	260	368
Adjustment of deferred tax liability for foreign income tax rate change	**—**	43	—
Total provision for income taxes on continuing operations	**$ 314**[(a)]	$ 180	$502[(b)]

(a) *Includes benefit of $30 million relating to certain prior year foreign exploration expenses.*
(b) *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:

Millions of dollars	**2003**	2002	2001
United States	**$ (245)**[(a)]	$(378)	$ 330
Foreign[(b)]	**1,026**	313	988
Total income from continuing operations	**$ 781**	$ (65)	$1,318

(a) *Includes substantially all of the Corporation's interest expense and the results of hedging activities.*
(b) *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 bases 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:

Millions of dollars	**2003**	2002
Deferred tax liabilities		
Fixed assets and investments	**$1,391**	$ 943
Foreign petroleum taxes	**281**	256
Other	**226**	138
Total deferred tax liabilities	**1,898**	1,337
Deferred tax assets		
Accrued liabilities	**209**	124
Dismantlement liability	**169**	—
Net operating loss carryforwards	**551**	543
Tax credit carryforwards	**155**	61
Other	**64**	33
Total deferred tax assets	**1,148**	761
Valuation allowance	**(93)**	(95)
Net deferred tax assets	**1,055**	666
Net deferred tax liabilities	**$ 843**	$ 671

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

	2003	2002	2001
United States statutory rate	**35.0%**	(35.0)%	35.0%
Effect of foreign operations, including foreign tax credits	**4.6**	321.5*	2.8
Loss on repurchase of bonds	**(.6)**	(15.4)	—
State income taxes, net of Federal income tax benefit	**(1.1)**	8.1	1.3
Prior year adjustments	**2.8**	(1.5)	(1.5)
Other	**(.4)**	(.1)	.5
Total	**40.3%**	277.6%	38.1%

**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 benefited 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 $2.6 billion at December 31, 2003 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 $100 million would have been required.

For income tax reporting at December 31, 2003, the Corporation has alternative minimum tax credit carryforwards of approximately $120 million, which can be carried forward indefinitely. The Corporation also has approximately $35 million of general business credits. At December 31, 2003, the Corporation has a net operating loss carryforward in the United States of approximately $450 million. At December 31, 2003, a net operating loss carryforward of approximately $500 million is also available to offset the Corporation's share of HOVENSA joint venture income 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 $550 million.

Income taxes paid (net of refunds) in 2003, 2002 and 2001 amounted to $361 million, $410 million and $605 million, respectively.

15. STOCKHOLDERS' EQUITY AND NET INCOME PER SHARE

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

Thousands of shares	**2003**	2002	2001
Common shares—basic	**88,618**	88,187	88,031
Effect of dilutive securities			
Convertible preferred stock	**1,425**	—	205
Nonvested common stock	**290**	—	425
Stock options	**9**	—	468
Common shares—diluted	**90,342**	88,187	89,129

The table above excludes the effect of out-of-the-money options on 4,170,000 shares, 633,000 shares and 139,000 shares in 2003, 2002 and 2001, respectively. In 2002, the table also excludes the antidilutive effect of 461,000 nonvested common shares, 424,000 stock options and 205,000 shares of convertible preferred stock.

Earnings per share are as follows:

	2003	2002	2001
Basic			
Continuing operations	**$5.21**	$(2.78)	$ 9.26
Discontinued operations	**1.91**	.30	1.12
Cumulative effect of change in accounting	**.07**	—	—
Net income (loss)	**$7.19**	$(2.48)	$10.38
Diluted			
Continuing operations	**$5.17**	$(2.78)	$ 9.15
Discontinued operations	**1.87**	.30	1.10
Cumulative effect of change in accounting	**.07**	—	—
Net income (loss)	**$7.11**	$(2.48)	$10.25

In 2003, the Corporation issued 13,500,000 shares of 7% cumulative mandatory convertible preferred stock. Dividends are payable on March 1, June 1, September 1 and December 1 of each year. The cumulative mandatory convertible preferred shares have a liquidation preference of $675 million ($50 per share). Each cumulative mandatory convertible preferred share will automatically convert on December 1, 2006 into .8305 to 1.0299 shares of common stock, depending on the average closing price of the Corporation's common stock over a 20-day period before conversion. The Corporation has reserved 13,903,650 shares of common stock for the conversion of these preferred shares. Holders of the cumulative mandatory convertible preferred stock have the right to convert their shares at any time prior to December 1, 2006 at the rate of .8305 share of common stock for each preferred share converted. The cumulative mandatory convertible preferred shares do not have voting rights, except in certain limited circumstances.

16. 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, 2003, future minimum rental payments applicable to noncancelable leases with remaining terms of one year or more (other than oil and gas property leases) are as follows:

Millions of dollars	*Operating Leases*	*Capital Leases*
2004	$ 95	$13
2005	71	13
2006	71	13
2007	71	13
2008	71	2
Remaining years	924	1
Total minimum lease payments	1,303	55
Less: Imputed interest	—	7
Income from subleases	36	—
Net minimum lease payments	$1,267	$48
Capitalized lease obligations		
Current		$10
Long-term		38
Total		$48

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 property leases, was as follows:

Millions of dollars	**2003**	2002	2001
Total rental expense	**$190**	$160	$206
Less income from subleases	**52**	34	63
Net rental expense	**$138**	$126	$143

17. 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.

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 prices of commodities to be sold under fixed-price contracts. 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 changes in fair value 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. Hedging decreased exploration and production results by $418 million before income taxes in 2003. Hedging increased exploration and production results before income taxes by $82 million in 2002 and $106 million in 2001 (including $82 million associated with the transition adjustment at the beginning of 2001). 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, 2003, 2002 and 2001.

The Corporation produced 95 million barrels of crude oil and natural gas liquids and 249 million Mcf of natural gas in 2003. The Corporation's crude oil and natural gas hedging activities included commodity futures and swap contracts. At December 31, 2003, crude oil hedges maturing in 2004 and 2005 cover 93 million barrels of crude oil production (91 million barrels of crude oil at December 31, 2002). The Corporation has natural gas hedges maturing in 2004 covering 18 million Mcf of natural gas production in the United States at December 31, 2003 (35 million Mcf of natural gas at December 31, 2002).

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, 2003, net after tax deferred losses in accumulated other comprehensive income from the Corporation's crude oil and natural gas hedging contracts expiring through 2005 were $229 million ($352 million before income taxes), including $196 million of unrealized losses. Of the net after tax deferred loss, $185 million matures during 2004. At December 31, 2002, net after-tax deferred losses were $91 million ($141 million before income taxes), including $71 million of unrealized losses.

In its energy marketing business, the Corporation has entered into cash flow hedges to fix the purchase prices of natural gas, heating oil, residual fuel oil and electricity. At December 31, 2003, the net after tax deferred gains in accumulated other comprehensive income from these contracts, expiring through 2007, were $45 million ($70 million before income taxes). Substantially all of the deferred gains will be recognized in 2004.

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 $30 million in 2003, $6 million in 2002 and $72 million in 2001.

Other 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 $384 million of notional value foreign currency forward contracts maturing in 2004 and 2005 ($307 million at December 31, 2002). 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 fair values of the foreign currency forward contracts recorded by the Corporation were receivables of $40 million at December 31, 2003 and $18 million at December 31, 2002.

The Corporation also has $229 million in letters of credit outstanding at December 31, 2003 ($149 million at December 31, 2002). Of the total letters of credit outstanding at December 31, 2003, $7 million represents contingent liabilities; the remaining $222 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. 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 financial instruments used in non-trading and trading activities:

Millions of dollars, asset (liability)	*Fair Value At Dec. 31*	
	2003	*2002*
Commodities	**$ —**	$ 27
Futures and forwards		
Assets	**219**	370
Liabilities	**(218)**	(378)
Options		
Held	**975**	65
Written	**(948)**	(27)
Swaps		
Assets	**1,157**	1,323
Liabilities	**(1,384)**	(1,394)

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, 2003 and 2002, except as follows:

Millions of dollars, asset (liability)	**2003** Balance Sheet Amount	**2003** Fair Value	2002 Balance Sheet Amount	2002 Fair Value
Fixed-rate notes receivable	**$ 363**	**$ 355**	$ 424	$ 364
Fixed-rate debt	**(3,935)**	**(4,434)**	(4,984)	(5,561)

Credit Risks: The Corporation's financial instruments expose it to 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. 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 $351 million at December 31, 2003, which are concentrated with counterparties as follows: domestic and foreign trading companies — 25%, gas and power companies — 25%, banks and major financial institutions — 22%, government entities — 15% and integrated energy companies — 7%.

18. GUARANTEES AND CONTINGENCIES

In the normal course of business, the Corporation provides guarantees principally for investees of the Corporation. These guarantees are contingent commitments that ensure performance 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, 2003 is $99 million ($358 million at December 31, 2002). This amount includes the Corporation's guarantee of $40 million of the senior debt obligation of HOVENSA (see note 7). The remainder relates generally to a loan guarantee of a natural gas pipeline in which the Corporation owns a 5% interest. The amount of this guarantee declines over its 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. SEGMENT INFORMATION

Financial information by major geographic area for each of the three years ended December 31, 2003 follows:

Millions of dollars	United States	Europe	Africa, Asia and other	Consolidated
2003				
Operating revenues	**$12,019**	**$1,694**	**$ 598**	**$14,311**
Property, plant and equipment (net)	**1,705**	**2,538**	**3,735**	**7,978**
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

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.

19. SEGMENT INFORMATION (CONTINUED)

The following table presents financial data by operating segment for each of the three years ended December 31, 2003:

Millions of dollars	*Exploration and Production*	*Refining and Marketing*	*Corporate and Interest*	*Consolidated**
2003				
Operating revenues				
Total operating revenues	**$ 3,153**	**$11,473**	**$ 1**	
Less: Transfers between affiliates	**316**	**—**	**—**	
Operating revenues from unaffiliated customers	**$ 2,837**	**$11,473**	**$ 1**	**$14,311**
Income (loss) from continuing operations	**$ 414**	**$ 327**	**$(274)**	**$ 467**
Discontinued operations	**170**	**—**	**(1)**	**169**
Income from cumulative effect of accounting change	**7**	**—**	**—**	**7**
Net income (loss)	**$ 591**	**$ 327**	**$(275)**	**$ 643**
Earnings of equity affiliates	**$ 13**	**$ 125**	**$ —**	**$ 138**
Interest income	**10**	**34**	**2**	**46**
Interest expense	**—**	**—**	**293**	**293**
Depreciation, depletion, amortization and lease impairment	**1,063**	**54**	**1**	**1,118**
Provision (benefit) for income taxes	**363**	**126**	**(175)**	**314**
Investments in equity affiliates	**—**	**1,055**	**—**	**1,055**
Identifiable assets	**9,149**	**4,267**	**567**	**13,983**
Capital employed	**6,270**	**2,820**	**191**	**9,281**
Capital expenditures	**1,286**	**66**	**6**	**1,358**
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

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

REPORT OF MANAGEMENT

Amerada Hess Corporation and Consolidated Subsidiaries

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 appointed by the Audit Committee of 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. In 2003, the Audit Committee met three times with the independent auditors and three times 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.

John B. Hess

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

John Y. Schreyer
Executive Vice President and Chief Financial Officer

REPORT OF ERNST & YOUNG LLP, INDEPENDENT AUDITORS

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, 2003 and 2002 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, 2003. 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, 2003 and 2002 and the consolidated results of their operations and their consolidated cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States.

As discussed in Notes 4 and 17 to the consolidated financial statements, the Corporation adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, effective January 1, 2003, and 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 20, 2004

SUPPLEMENTARY OIL AND GAS DATA (UNAUDITED)

Amerada Hess Corporation and Consolidated Subsidiaries

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, Algeria, Gabon, Indonesia, Thailand and Azerbaijan. Exploration activities are also conducted, or are planned, in additional countries.

In 2001 and 2002, the Corporation had two equity investees and reported its proportionate share of their oil and gas data in the following tables. As a result of transactions in 2003, one of these equity investees was consolidated and the other was exchanged for other oil and gas interests. Previously, the Corporation owned a 25% interest in certain oil and gas fields in the joint development area of Malaysia and Thailand (JDA) through a 50% investment in a joint venture that was accounted for as an equity investment. In 2003, the Corporation exchanged producing properties in Colombia for the remaining 50% of the JDA joint venture. As a result of this exchange, the Corporation has consolidated its oil and gas interests in the JDA. In 2003, the Corporation exchanged its 25% equity investment in Premier Oil plc for an interest in a producing field in Indonesia.

During 2003, the Corporation exchanged its interests in producing oil and gas fields in the United Kingdom for an increased interest in a Gulf of Mexico field under development. 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 (Millions of dollars)	*Total*	*United States*	*Europe*	*Africa, Asia and other*
2003				
Property acquisitions				
Unproved	**$ 16**	**$ 16**	**$ —**	**$ —**
Proved	**23**	**—**	**—**	**23**
Exploration	**321**	**143**	**49**	**129**
Production and development*	**1,082**	**118**	**501**	**463**
2002				
Property acquisitions				
Unproved	$ 23	$ 22	$ —	$ 1
Proved	70	—	—	70
Exploration	335	120	53	162
Production and development	1,095	146	509	440
Share of equity investees' costs incurred	39	—	25	14
2001				
Property acquisitions				
Unproved	$ 820	$121	$ 1	$ 698
Proved	2,772	831	—	1,941
Exploration	297	107	87	103
Production and development	1,182	322	516	344
Share of equity investees' costs incurred	14	—	9	5

* *Includes $15 million that the Corporation has capitalized related to asset retirement obligations accrued during 2003. Also see Note 4 to the financial statements entitled* Accounting Change.

CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES

At December 31 (Millions of dollars)	**2003**	2002
Unproved properties	**$ 950**	$ 1,020
Proved properties	**2,634**	2,843
Wells, equipment and related facilities	**11,030**	10,836
Total costs	**14,614**	14,699
Less: Reserve for depreciation, depletion, amortization and lease impairment	**7,512**	8,539
Net capitalized costs	**$ 7,102***	$ 6,160
Share of equity investees' capitalized costs	**$ —**	$ 704

* *Includes amounts related to asset retirement obligations.*

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 19 to the financial statements.

RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

For the Years Ended December 31 (Millions of dollars)	*Total*	*United States*	*Europe*	*Africa, Asia and other*
2003				
Sales and other operating revenues				
Unaffiliated customers	**$2,771**	**$ 469**	**$1,716**	**$ 586**
Inter-company	**316**	**316**	**—**	**—**
Total revenues	**3,087**	**785**	**1,716**	**586**
Costs and expenses				
Production expenses, including related taxes	**796**	**194**	**408**	**194**
Exploration expenses, including dry holes and lease impairment	**369**	**147**	**60**	**162**
General, administrative and other expenses	**168***	**65**	**63**	**40**
Depreciation, depletion and amortization	**998**	**260**	**553**	**185**
Total costs and expenses	**2,331**	**666**	**1,084**	**581**
Results of continuing operations before income taxes	**756**	**119**	**632**	**5**
Provision for income taxes	**358**	**42**	**291**	**25**
Results of continuing operations	**398**	**77**	**341**	**(20)**
Discontinued operations	**42**	**25**	**4**	**13**
Results of operations	**$ 440**	**$ 102**	**$ 345**	**$ (7)**
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
General, administrative and other 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
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
General, administrative and other 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

** Includes accrued severance and London office lease costs of approximately $40 million.*

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, 32% of the Corporation's December 31, 2003 worldwide proved reserves are undeveloped. The estimates of the Corporation's proved reserves of crude oil and natural gas (after deducting royalties and operating 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, 2001	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**	**782**	**539**	**852**	**350**	**1,741**	**736**	**2,477**
Revisions of previous estimates[a]	**8**	**8**	**33**	**49**	**—**	**49**	**(8)**	**14**	**(25)**	**(19)**	**—**	**(19)**
Extensions, discoveries and other additions	**1**	**6**	**4**	**11**	**—**	**11**	**3**	**81**	**4**	**88**	**—**	**88**
Purchases of minerals in-place[c]	**8**	**—**	**14**[b]	**22**	**(6)**[b]	**16**	**21**	**—**	**1,023**[b]	**1,044**	**(405)**[b]	**639**
Sales of minerals in-place[c]	**(8)**	**(20)**	**(81)**	**(109)**	**(7)**	**(116)**	**(103)**	**(13)**	**(157)**	**(273)**	**(316)**	**(589)**
Production	**(20)**	**(53)**	**(22)**	**(95)**	**(1)**	**(96)**	**(92)**	**(134)**	**(23)**	**(249)**	**(15)**	**(264)**
At December 31, 2003	**127**	**305**	**214**	**646**	**—**	**646**[d]	**360**[e]	**800**	**1,172**	**2,332**	**—**	**2,332**[d]
Net Proved Developed Reserves												
At January 1, 2001	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
At December 31, 2003	**105**	**249**	**111**	**465**	**—**	**465**	**297**	**518**	**633**	**1,448**	**—**	**1,448**

(a) Includes the impact of changes in selling prices on production sharing contracts with cost recovery provisions and stipulated rates of return. In 2003 such revisions were immaterial. In 2002 revisions included reductions of approximately 44 million barrels of crude oil and 26 million Mcf of natural gas relating to higher selling prices. In 2002 revisions also reflected reductions in reserves on fields acquired in the LLOG and Triton acquisitions.

(b) Includes the reclassification of reserves to "Africa, Asia and other" from "Equity Investees" as a result of the consolidation of the Corporation's interest in the JDA.

(c) Includes additions and reductions to reserves from asset exchanges.

(d) Includes 32% of crude oil reserves and 43% 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.

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

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 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 (Millions of dollars)	*Total*	*United States*	*Europe*	*Africa, Asia and other*
2003				
Future revenues	**$27,649**	**$5,742**	**$12,417**	**$9,490**
Less:				
Future development and production costs	**10,065**	**1,546**	**5,181**	**3,338**
Future income tax expenses	**5,848**	**1,299**	**3,496**	**1,053**
	15,913	**2,845**	**8,677**	**4,391**
Future net cash flows	**11,736**	**2,897**	**3,740**	**5,099**
Less: Discount at 10% annual rate	**4,719**	**1,062**	**1,333**	**2,324**
Standardized measure of discounted future net cash flows	**$ 7,017**	**$1,835**	**$ 2,407**	**$2,775**
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
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

CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

For the years ended December 31 (Millions of dollars)	**2003**	2002	2001
Standardized measure of discounted future net cash flows at beginning of year	**$ 7,085**	$ 5,056	$ 6,828
Changes during the year			
Sales and transfers of oil and gas produced during year, net of production costs	**(2,291)**	(2,964)	(2,840)
Development costs incurred during year	**1,082**	1,095	1,182
Net changes in prices and production costs applicable to future production	**796**	5,767	(4,346)
Net change in estimated future development costs	**(726)**	(546)	(838)
Extensions and discoveries (including improved recovery) of oil and gas reserves, less related costs	**261**	287	521
Revisions of previous oil and gas reserve estimates	**622**	(939)	231
Purchases (sales) of minerals in-place, net	**(469)**	(247)	1,186
Accretion of discount	**945**	796	1,087
Net change in income taxes	**72**	(1,701)	1,943
Revision in rate or timing of future production and other changes	**(360)**	481	102
Total	**(68)**	2,029	(1,772)
Standardized measure of discounted future net cash flows at end of year	**$ 7,017**	$ 7,085	$ 5,056

TEN-YEAR SUMMARY OF FINANCIAL DATA

Amerada Hess Corporation and Consolidated Subsidiaries

Millions of dollars, except per share data	**2003**	2002	2001
STATEMENT OF CONSOLIDATED INCOME			
Revenues and Non-operating Income			
Sales (excluding excise taxes) and other operating revenues			
Crude oil (including sales of purchased oil)	**$ 2,032**	$ 2,471	$ 2,099
Natural gas (including sales of purchased gas)	**4,522**	3,078	4,503
Petroleum products	**6,513**	4,865	5,303
Other operating revenues	**1,244**	1,137	1,147
Total	**14,311**	11,551	13,052
Non-operating income			
Gain on asset sales	**39**	143	—
Equity in income (loss) of HOVENSA L.L.C.	**117**	(47)	58
Other	**13**	85	150
Total revenues and non-operating income	**14,480**	11,732	13,260
Costs and expenses			
Cost of products sold	**9,947**	7,226	8,739
Production expenses	**796**	736	642
Marketing expenses	**709**	703	663
Exploration expenses, including dry holes and lease impairment	**369**	316	347
Other operating expenses	**192**	165	213
General and administrative expenses	**340**	253	311
Interest expense	**293**	256	194
Depreciation, depletion and amortization	**1,053**	1,118	833
Impairment of assets and operating leases	**—**	1,024	—
Total costs and expenses	**13,699**	11,797	11,942
Income (loss) from continuing operations before income taxes	**781**	(65)	1,318
Provision (benefit) for income taxes	**314**	180	502
Income (loss) from continuing operations	**467**	(245)(b)	816(d)
Discontinued operations	**169(a)**	27	98
Cumulative effect of change in accounting principle	**7**	—	—
NET INCOME (LOSS)	**$ 643**	$ (218)	$ 914
Less preferred stock dividends	**5**	—	—
NET INCOME (LOSS) APPLICABLE TO COMMON SHAREHOLDERS	**$ 638**	$ (218)	$ 914
Basic earnings (loss) per share			
Continuing operations	**$ 5.21**	$ (2.78)	$ 9.26
Net income (loss)	**7.19**	(2.48)	10.38
Diluted earnings (loss) per share			
Continuing operations	**$ 5.17**	$ (2.78)	$ 9.15
Net income (loss)	**7.11**	(2.48)	10.25
DIVIDENDS PER SHARE OF COMMON STOCK	**$ 1.20**	$ 1.20	$ 1.20
WEIGHTED AVERAGE DILUTED SHARES OUTSTANDING (THOUSANDS)	**90,342**	88,187(c)	89,129

(a) Reflects net gains from asset sales of $116 million and income from operations prior to sale of $53 million.
(b) Includes net after-tax charges aggregating $708 million ($931 million before income taxes), principally resulting from asset impairments. See Note 2 to consolidated financial statements.
(c) Represents basic shares.
(d) Includes 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.
(e) Includes an after-tax gain of $60 million ($97 million before income taxes) on termination of an acquisition, partially offset by a $24 million ($38 million before income taxes) charge for costs associated with a research and development venture.
(f) On January 1, 1999, the Corporation adopted the last-in, first-out (LIFO) inventory method for refining and marketing inventories.
(g) Includes after-tax gains on asset sales of $176 million ($273 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).
See accompanying notes to consolidated financial statements, including Note 5 on Acquisition of Triton Energy Limited in August of 2001.

2000	1999[f]	1998	1997	1996	1995	1994
$ 2,022	$ 1,322	$ 836	$ 1,338	$ 1,426	$ 1,480	$ 1,178
3,239	1,800	1,645	1,306	1,241	1,005	901
5,539	3,003	3,464	4,958	5,081	4,311	3,981
947	770	509	413	296	303	328
11,747	6,895	6,454	8,015	8,044	7,099	6,388
—	273	(26)	16	529	96	42
121	7	(16)	—	—	—	—
165	140	83	120	125	125	49
12,033	7,315	6,495	8,151	8,698	7,320	6,479
7,885	4,239	4,373	5,577	5,387	4,501	3,795
522	453	478	513	573	561	550
542	387	379	329	264	259	261
282	260	350	422	382	382	331
234	217	224	232	129	186	124
222	232	271	235	237	263	230
162	158	153	136	166	247	245
676	610	598	595	644	693	741
—	128	206	80	—	584	—
10,525	6,684	7,032	8,119	7,782	7,676	6,277
1,508	631	(537)	32	916	(356)	202
591	240	(62)	85	319	37	138
917[e]	391[g]	(475)	(53)	597	(393)	64
106	47	16	61	63	(1)	10
—	—	—	—	—	—	—
$ 1,023	$ 438	$ (459)	$ 8	$ 660	$ (394)	$ 74
—	—	—	—	—	—	—
$ 1,023	$ 438	$ (459)	$ 8	$ 660	$ (394)	$ 74
$ 10.29	$ 4.36	$ (5.30)	$ (.58)	$ 6.45	$ (4.25)	$ .69
11.48	4.88	(5.12)	.08	7.13	(4.26)	.80
$ 10.20	$ 4.33	$ (5.30)	$ (.58)	$ 6.41	$ (4.25)	$ .69
11.38	4.85	(5.12)	.08	7.09	(4.26)	.79
$ .60	$ .60	$ .60	$ .60	$ .60	$ .60	$ .60
89,878	90,280	89,585[c]	91,733	93,110	92,509[c]	92,968

TEN-YEAR SUMMARY OF FINANCIAL DATA

Amerada Hess Corporation and Consolidated Subsidiaries

Millions of dollars, except per share data	**2003**	2002	2001
SELECTED BALANCE SHEET DATA AT YEAR-END			
Cash and cash equivalents	**$ 518**	$ 197	$ 37
Working capital	**517**	203	228
Property, plant and equipment			
Exploration and production	**$14,614**	$14,699	$15,194
Refining and marketing	**1,486**	1,450	1,433
Total—at cost	**16,100**	16,149	16,627
Less reserves	**8,122**	9,117	8,462
Property, plant and equipment—net	**$ 7,978**	$ 7,032	$ 8,165
Total assets	**$13,983**	$13,262	$15,369
Total debt	**3,941**	4,992	5,665
Stockholders' equity	**5,340**	4,249	4,907
Stockholders' equity per share, assuming conversion of preferred stock	**$ 51.50**	$ 47.45	$ 55.11
SUMMARIZED STATEMENT OF CASH FLOWS			
Net cash provided by operating activities	**$ 1,581**	$ 1,965	$ 1,960
Cash flows from investing activities			
Capital expenditures			
Exploration and production	**(1,286)**	(1,404)	(5,061)
Refining and marketing	**(72)**	(130)	(160)
Total capital expenditures	**(1,358)**	(1,534)	(5,221)
Proceeds from sales of property, plant and equipment and other	**581**	438	16
Net cash provided by (used in) investing activities	**(777)**	(1,096)	(5,205)
Cash flows from financing activities			
Debt with maturities of 90 days or less—increase (decrease)	**(2)**	(581)	564
Debt with maturities of greater than 90 days			
Borrowings	**—**	637	2,595
Repayments	**(1,026)**	(686)	(54)
Proceeds from issuance of preferred stock	**653**	—	—
Cash dividends paid	**(108)**	(107)	(94)
Common stock acquired	**—**	—	(100)
Stock options exercised	**—**	28	59
Net cash provided by (used in) financing activities	**(483)**	(709)	2,970
Net increase (decrease) in cash and cash equivalents	**$ 321**	$ 160	$ (275)
STOCKHOLDER DATA AT YEAR-END			
Number of common shares outstanding (thousands)	**89,868**	89,193	88,757
Number of stockholders (based on number of holders of record)	**6,983**	7,272	6,481
Market price of common stock	**$ 53.17**	$ 55.05	$ 62.50

2000	1999	1998	1997	1996	1995	1994
$ 312	$ 41	$ 74	$ 91	$ 113	$ 56	$ 53
577	249	90	464	690	358	520
$10,499	$ 9,974	$ 9,718	$ 8,780	$ 8,233	$ 9,392	$ 9,791
1,399	1,091	1,309	3,842	3,669	3,672	4,514
11,898	11,065	11,027	12,622	11,902	13,064	14,305
7,575	7,013	6,835	7,431	6,995	7,694	7,939
$ 4,323	$ 4,052	$ 4,192	$ 5,191	$ 4,907	$ 5,370	$ 6,366
$10,274	$ 7,728	$ 7,883	$ 7,935	$ 7,784	$ 7,756	$ 8,338
2,050	2,310	2,652	2,127	1,939	2,718	3,340
3,883	3,038	2,643	3,216	3,384	2,660	3,100
$ 43.58	$ 33.51	$ 29.26	$ 35.16	$ 36.35	$ 28.60	$ 33.33
$ 1,795	$ 746	$ 519	$ 1,250	$ 808	$ 1,241	$ 957
(783)	(727)	(1,307)	(1,158)	(788)	(626)	(532)
(155)	(70)	(132)	(188)	(73)	(66)	(64)
(938)	(797)	(1,439)	(1,346)	(861)	(692)	(596)
36	397	500	61	1,040	148	74
(902)	(400)	(939)	(1,285)	179	(544)	(522)
(131)	(1,060)	213	398	(825)	(352)	(575)
20	990	441	2	—	25	290
(296)	(273)	(137)	(209)	(42)	(311)	(121)
—	—	—	—	—	—	—
(54)	(54)	(55)	(55)	(56)	(56)	(56)
(220)	—	(59)	(122)	(8)	—	—
59	18	—	—	—	—	—
(622)	(379)	403	14	(931)	(694)	(462)
$ 271	$ (33)	$ (17)	$ (21)	$ 56	$ 3	$ (27)
88,744	90,676	90,357	91,451	93,073	93,011	92,996
7,709	7,416	8,959	9,591	10,153	11,294	11,506
$ 73.06	$ 56.75	$ 49.75	$ 54.88	$ 57.88	$ 53.00	$ 45.63

TEN-YEAR SUMMARY OF OPERATING DATA

Amerada Hess Corporation and Consolidated Subsidiaries

	2003	2002	2001
PRODUCTION PER DAY (NET)			
Crude oil (thousands of barrels)			
United States	**44**	54	63
United Kingdom	**89**	112	119
Norway	**24**	24	25
Denmark	**24**	23	20
Equatorial Guinea	**22**	37	6
Algeria	**19**	15	13
Gabon	**11**	9	9
Indonesia	**1**	4	6
Azerbaijan	**2**	4	4
Colombia	**3**	22	10
Other	**—**	—	—
Total	**239**	304	275
Natural gas liquids (thousands of barrels)			
United States	**11**	12	14
United Kingdom	**6**	6	7
Norway	**1**	1	1
Thailand	**2**	2	1
Other	**—**	—	—
Total	**20**	21	23
Natural gas (thousands of Mcf)			
United States	**253**	373	424
United Kingdom	**312**	277	291
Thailand	**52**	35	20
Denmark	**29**	37	43
Norway	**26**	25	25
Indonesia	**11**	6	8
Other	**—**	1	1
Total	**683**	754	812
Barrels of oil equivalent (thousands of barrels per day)[e]	**373**	451	433
WELL COMPLETIONS (NET)			
Oil wells	**30**	38	50
Gas wells	**13**	39	31
Dry holes	**13**	16	15
PRODUCTIVE WELLS AT YEAR-END (NET)			
Oil wells	**795**	760	858
Gas wells	**236**	237	257
Total	**1,031**	997	1,115
UNDEVELOPED NET ACREAGE AT YEAR-END (THOUSANDS)			
United States	**940**	743	625
Foreign[a]	**8,143**	12,224	15,999
Total	**9,083**	12,967	16,624
REFINING (THOUSANDS OF BARRELS PER DAY)			
Amerada Hess Corporation	**—**	—	—
HOVENSA L.L.C.[c]	**220**	181	202
PETROLEUM PRODUCTS SOLD (THOUSANDS OF BARRELS PER DAY)			
Gasoline, distillates and other light products	**351**	329	322
Residual fuel oils	**68**	54	65
Total	**419**	383	387
STORAGE CAPACITY AT YEAR-END (THOUSANDS OF BARRELS)	**36,028**	36,140	36,298
NUMBER OF EMPLOYEES (AVERAGE)	**11,481**[d]	11,662	10,838

(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 7,100 employees of retail operations.
(e) Includes barrels of oil equivalent production per day (in thousands) of 13 in 2003, 51 in 2002, 45 in 2001, 26 in 2000, 27 in 1999 and 25 in 1998 related to operations discontinued in 2003.

2000	1999	1998	1997	1996	1995	1994
55	55	37	35	41	52	56
119	112	109	126	135	135	122
25	25	27	30	28	26	24
25	7	—	—	—	—	—
—	—	—	—	—	—	—
2	—	—	—	—	—	—
7	10	14	10	9	10	9
4	3	3	1	—	—	—
3	2	—	—	—	—	—
—	—	—	—	—	—	—
—	—	—	—	6	17	18
240	214	190	202	219	240	229
12	10	8	8	9	11	12
6	5	6	6	7	7	7
2	2	2	2	2	1	1
1	1	—	—	—	—	—
—	—	—	—	—	2	2
21	18	16	16	18	21	22
288	338	294	312	338	402	427
297	258	251	226	254	239	209
23	8	—	—	—	—	—
37	3	—	—	—	—	—
24	31	28	30	30	28	24
10	5	3	1	—	—	—
—	—	—	—	63	215	186
679	643	576	569	685	884	846
374	339	302	313	351	408	392
29	28	28	42	39	33	28
11	11	20	11	25	41	44
18	9	25	24	40	50	24
774	735	721	860	854	2,154	2,160
188	161	252	447	455	1,160	1,146
962	896	973	1,307	1,309	3,314	3,306
616	678	748	915	891	1,440	1,685
14,419	15,858	16,927	10,180	7,455	5,871	4,570
15,035	16,536	17,675	11,095	8,346	7,311	6,255
—	—	419(b)	411	396	377	388
211	209	217	—	—	—	—
304	284	411	436	412	401	375
62	60	71	73	83	86	93
366	344	482	509	495	487	468
37,487	38,343	56,070	87,000	86,986	89,165	94,597
9,891	8,485	9,777	9,216	9,085	9,574	9,858

AMERADA HESS CORPORATION

BOARD OF DIRECTORS

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Chairman of the Board
and Chief Executive Officer

Nicholas F. Brady (1) (3) (4)
Chairman, Choptank
Partners, Inc.;
Former Secretary of the
United States Department
of the Treasury;
Former Chairman,
Dillon, Read & Co., Inc.

J. Barclay Collins II
Executive Vice President
and General Counsel

Edith E. Holiday (2) (4)
Corporate Director
and Trustee;
Former Assistant to
the President and
Secretary of the Cabinet;
Former General Counsel
United States Department
of the Treasury

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President, Drew University;
Former Governor
State of New Jersey

Craig G. Matthews (2)
Chief Executive Officer
and President, NUI, Inc.;
Former Vice Chairman and
Chief Operating Officer,
KeySpan Corporation

John J. O'Connor
Executive Vice President
President, Worldwide
Exploration & Production

Frank A. Olson (2) (3)
Former Chairman of the Board
and Chief Executive Officer,
The Hertz Corporation

John Y. Schreyer
Executive Vice President
and Chief Financial Officer

Ernst H. von Metzsch (3)
Former Senior Vice President
and Partner,
Wellington Management
Company

Robert N. Wilson (1) (2) (3)
Former Senior Vice Chairman
of the Board of Directors,
Johnson & Johnson

(1) Member of Executive Committee
(2) Member of Audit Committee
(3) Member of Compensation and Management Development Committee
(4) Member of Corporate Governance and Nominating Committee

CORPORATE OFFICERS

LEADERSHIP TEAM (left to right) J. B. Collins, J. J. O'Connor, J. B. Hess, J. Y. Schreyer and F. B. Walker

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

J. B. Collins
Executive Vice President
and General Counsel

J. J. O'Connor
Executive Vice President
President, Worldwide
Exploration and Production

J. Y. Schreyer
Executive Vice President
and Chief Financial Officer

F. B. Walker
Executive Vice President
President, Refining and
Marketing

SENIOR VICE PRESIDENTS

E.C. Crouch
J.A. Gartman
N. Gelfand
G.A. Jamin
Treasurer
L.H. Ornstein
H. Paver
G.F. Sandison
R.P. Strode

VICE PRESIDENTS

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Secretary
R. J. Bartzokas
G. I. Bresnick
L. L. Chan
R.E. Guerry
D.K. Kirshner
R. J. Lawlor
J. J. Lynett
L.S. Massaro
J.P. Rielly
Controller
R.B. Ross
J. J. Scelfo
E.S. Smith
J.R. Wilson

COMMON STOCK

Listed
New York Stock Exchange
(ticker symbol: AHC)

Transfer Agent
The Bank of New York
Shareholder Relations
Department-11E
P.O. Box 11258
Church Street Station
New York, New York 10286
1-800-524-4458
e-mail: shareowner-svcs@bankofny.com

Registrar
The Bank of New York
Shareholder Relations
Department-11E
P.O. Box 11258
New York, New York 10286
1-800-524-4458

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(212) 997-8500

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33 Grosvenor Place
London SW1X 7HY
England

Refining and Marketing
Amerada Hess Corporation
1 Hess Plaza
Woodbridge, New Jersey 07095

DOCUMENTS AVAILABLE
Copies of the Corporation's 2003 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and its annual proxy statement filed with the Securities and Exchange Commission, as well as the Corporation's Code of Business Conduct and Ethics, its Corporate Governance Guidelines, and charters of the Audit Committee, Compensation and Management Development Committee and Corporate Governance and Nominating Committee of the Board of Directors, are available, without charge, on our website listed below or upon written request to the Corporate Secretary, Amerada Hess Corporation, 1185 Avenue of the Americas, New York, New York 10036.
e-mail: corporatesecretary@hess.com

ANNUAL MEETING
The Annual Meeting of Stockholders will be held on Wednesday, May 5, 2004 at 2:00 P.M., 1 Hess Plaza, Woodbridge, New Jersey 07095.

DIVIDEND REINVESTMENT PLAN
Information concerning the Dividend Reinvestment Plan available to holders of Amerada Hess Corporation Common Stock may be obtained by writing to The Bank of New York Dividend Reinvestment Department, P.O. Box 1958, Newark, New Jersey 07101

Amerada Hess Website
www.hess.com

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