MANAGEMENT'S DISCUSSION AND ANALYSIS

INTRODUCTION

We use the Management's Discussion and Analysis (MD&A) to explain Texaco's operating results and general financial condition. A table of financial highlights that provides a financial picture of the company is followed by four main sections: Industry Review, Results of Operations, Analysis of Income by Operating Segments and Other Items. Earnings information is presented on an after-tax basis, unless otherwise noted.

Industry Review — We discuss the economic factors that affected our industry in 2000. We also provide our near-term outlook for the industry.

Results of Operations — We explain changes in revenues, costs, expenses and income taxes. Summary schedules, showing results before and after special items, complete this section. Special items are significant benefits or charges outside the scope of normal operations.

Analysis of Income by Operating Segments — We discuss the performance of our operating segments: Exploration and Production (upstream), Refining, Marketing and Distribution (downstream) and Global Gas, Power and Energy Technology. We also discuss Other Business Units and our Corporate/Non-operating results.

Other Items — We discuss the following items in this section:

- Liquidity and Capital Resources: How we manage cash, working capital and debt and other actions to provide financial flexibility
- Reorganizations, Restructurings and Employee Separation Programs: A discussion of our reorganizations and other cost-cutting initiatives
- Capital and Exploratory Expenditures: Our program to invest in the business, especially in projects aimed at future growth
- Environmental Matters: A discussion about our expenditures relating to protection of the environment
- New Accounting Standards: A description of new accounting standards to be adopted
- Euro Conversion: The status of our program to adapt to the euro currency
- California Power Situation: A discussion of the current power problems facing California
- Chevron-Texaco Merger: The status of our proposed merger with Chevron

Our discussions in the MD&A and other sections of this Annual Report contain forward-looking statements that are based upon our best estimate of the trends we know about or anticipate. Actual results may be different from our estimates. We have described in our 2000 Annual Report on Form 10-K the factors that could change these forward-looking statements.

FINANCIAL HIGHLIGHTS

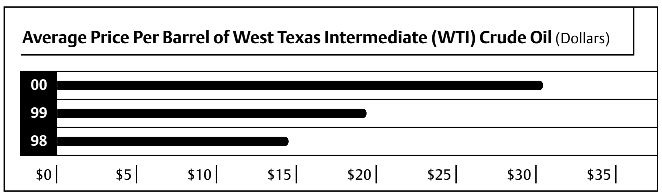
(Millions of dollars, except per share and ratio data)	**2000**	1999	1998
Revenues	**$ 51,130**	$ 35,691	$ 31,707
Income before special items and cumulative effect of accounting change	**$ 2,898**	$ 1,214	$ 894
Special items	**(356)**	(37)	(291)
Cumulative effect of accounting change	**—**	—	(25)
Net income	**$ 2,542**	$ 1,177	$ 578
Diluted income per common share *(dollars)*			
Income before special items and cumulative effect of accounting change	**$ 5.31**	$ 2.21	$ 1.59
Special items	**(.66)**	(.07)	(.55)
Cumulative effect of accounting change	**—**	—	(.05)
Net income	**$ 4.65**	$ 2.14	$ .99
Cash dividends per common share *(dollars)*	**$ 1.80**	$ 1.80	$ 1.80
Total assets	**$ 30,867**	$ 28,972	$ 28,570
Total debt	**$ 7,191**	$ 7,647	$ 7,291
Stockholders' equity	**$ 13,444**	$ 12,042	$ 11,833
Current ratio	**1.18**	1.05	1.07
Return on average stockholders' equity*	**20.1%**	10.0%	4.9%
Return on average capital employed before special items*	**16.2%**	8.3%	6.5%
Return on average capital employed*	**14.5%**	8.1%	5.0%
Total debt to total borrowed and invested capital	**33.7%**	37.5%	36.8%

*Returns for 1998 exclude the cumulative effect of accounting change (see Note 2 to the financial statements).

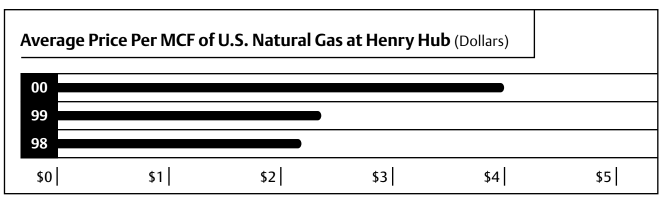
INDUSTRY REVIEW

Introduction

By most measures, 2000 was an extraordinary year for the international oil and gas industry. Spot crude oil prices reached their highest average level since 1982, spot refining margins staged a startling recovery from last year's lows and U.S. natural gas prices set new records.



Prices in 2000 reached their highest average level since 1982.



Prices in 2000 reached record highs.

A surging global economy contributed to further growth in energy demand last year. However, the very favorable price environment was, to a large extent, the result of a combination of energy market supply-side factors. Low inventories of crude oil and refined products left oil markets susceptible to disruption and uncertainty. This helped to support prices and refining margins at high levels for most of the year.

Low inventory levels also characterized the U.S. natural gas market. Domestic gas production remained relatively weak in 2000. This made it difficult both to meet summer demand requirements and to place adequate volumes of gas into storage for the winter.

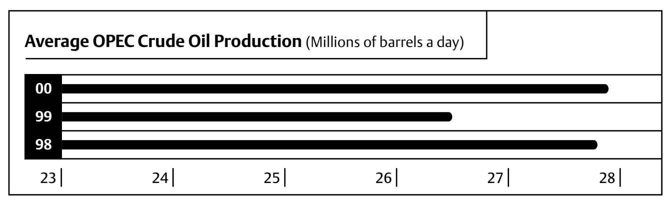
Review of 2000

The global economy experienced exceptionally strong growth in 2000. The U.S. was the world's driving force, enjoying a remarkable 5% increase in Gross Domestic Product despite a tightening in monetary policy and higher energy prices. Western Europe also registered a healthy gain, propelled by rising exports and strong investment spending. However, the large Japanese economy continued to underperform.

The developing world continued to recover in 2000 from the Asian financial crisis. Benefiting from both a rise in intra-regional trade and the strength of the U.S. and European economies, growth in developing Asia accelerated. In similar fashion, Latin America emerged from its 1999 recession, led by strong growth in Brazil, Mexico, Peru and Chile. Also, many of the oil producing nations in the developing world benefited from higher oil prices. Furthermore, the former Soviet bloc enjoyed its strongest economic performance in 10 years, led by robust growth in Russia and many of the countries in Eastern Europe.

The increased pace of economic activity contributed to further growth in world oil demand. Total oil consumption averaged 76.4 million barrels per day (BPD) during 2000, 1.2% higher than 1999. Virtually all of the increase in demand occurred in the developing countries, especially those in Asia. The warmer-than-normal 1999-2000 winter constrained the demand for heating fuels in the U.S. and Western Europe. Also, sharply higher oil prices limited consumption in some countries.

In contrast to the deep cutbacks made in 1999, members of the Organization of Petroleum Exporting Countries (OPEC) raised their production of crude oil significantly in 2000. OPEC crude oil output averaged 27.9 million BPD, 1.4 million BPD above the prior year and the highest level since 1979. By year end, many OPEC members were believed to be producing at or near their full capacity.



OPEC increased production in 2000 to stabilize prices.

Production in non-OPEC areas also rose substantially in 2000. This largely reflected the start-up of projects that were delayed from the prior two years, when low oil prices cut deeply into spending and production plans. However, much of the increase in world oil production occurred after the spring, and commercial crude oil inventories remained lean throughout most of the year.

Low crude oil stocks placed continued upward pressure on prices. This was reinforced by uncertainties regarding export flows from Iraq and the escalation of violence in the Middle East. For the year overall, the spot price of U.S. benchmark West Texas Intermediate (WTI) crude oil averaged $30.37 per barrel, about $11.00 per barrel higher than in 1999.

FOR 2000, WTI CRUDE OIL PRICES AVERAGED $30.37 PER BARREL, OR 57% ABOVE THE 1999 AVERAGE.

Early in 2000, refined product inventories were drawn down, especially in the Atlantic basin, to meet seasonal demand requirements. As the year progressed, it became difficult to replenish these stocks for a variety of reasons. These reasons included changes in mandated product specifications in some areas, scattered worldwide refinery outages and heavy scheduled refinery maintenance. Consequently, refined product prices rose sharply, and spot refining margins increased.

U.S. natural gas prices also rose steeply last year, averaging $3.99 per thousand cubic feet. This increase of about 70% reflected tight supply/demand conditions. Domestic gas production has recovered slowly from the declines suffered in 1998-1999 when overall upstream spending was reduced drastically due to low oil prices. At the same time, however, gas demand has trended upward, especially for electricity generation during the summer months. During 2000, natural gas end users competed for available supplies with operators who store gas for the winter. With low levels of gas in storage heading into the winter, the onset of severe cold weather in November and December raised concerns about adequate supplies. This sent prices up sharply.

Near-Term Outlook

The global economic expansion is expected to continue through 2001, though at a slower rate than in 2000. The U.S. economy is showing signs of a sharp slowdown, responding to the previous interest rate increases by the Federal Reserve. Economic expansions in Europe and the developing world are also expected to moderate, reflecting the slowdown in the U.S.

World oil consumption will increase again during 2001. Even with lower economic growth, oil consumption should rise by about 1.4 million BPD. On the supply side, non-OPEC production will also rise, but more slowly, as many delayed projects have been completed.

The major uncertainty facing oil markets in 2001 concerns the level of OPEC oil output and the future course of prices. OPEC has stated publicly its desire to maintain crude oil prices in a target range which is roughly equivalent to $24-$30 per barrel of WTI. Prices were headed down toward the lower end of that range by the end of 2000 as OPEC's high crude oil production rates ultimately translated into a worldwide accumulation of crude oil stocks. To avoid a market oversupply situation which could jeopardize its price goal, OPEC implemented output restraints early in 2001.

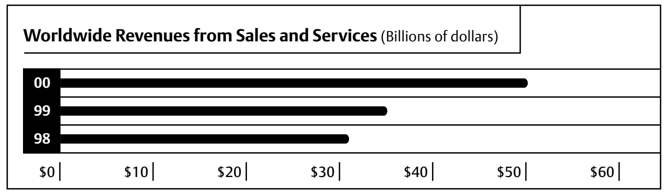
Worldwide spot refining margins should decline during 2001. High refinery running rates in many parts of the world during the latter part of last year led to a partial refilling of refined product stocks. In addition, many of the unusual factors that prevailed in 2000, such as major changes in product specifications, should be absent from the market in 2001.

U.S. natural gas markets, on the other hand, have the potential to remain quite strong in 2001. Under any reasonable expectation, the volume of natural gas in storage will be very low by the spring. Thus, the need to build supplies will be intense. Although production and imports will be higher, continued growth in demand will keep the market balance tight.

RESULTS OF OPERATIONS

Revenues

Our consolidated worldwide revenues were $51.1 billion in 2000, $35.7 billion in 1999 and $31.7 billion in 1998.



Our revenues in 2000 reflect the run-up in crude oil, refined product and natural gas prices.

Sales Revenues — Price/Volume Effects

Our sales revenues were higher in 2000 due to an increase of over 60% in our realized crude oil prices. However, our crude oil and natural gas liquids production was 10% lower due to sales of non-core producing properties in the U.S. and U.K. and natural field declines.

Sales revenues from petroleum products increased in 2000 led by higher prices in all markets. Volumes increased slightly as higher sales in the U.S. and Europe were offset by decreases in Latin America and West Africa and lower natural gas liquids (NGL) trading activity in our international areas.

U.S. natural gas revenues also improved in 2000 due to a significant increase in our realized natural gas price, as well as higher sales of purchased gas. Results for our international operations were consistent with 1999.

Our sales revenues were higher in 1999 due to our increased realized crude oil prices which began to rise during the second half of the year. However, crude oil and NGL production declined due to natural field declines and asset sales in the U.S., as well as temporary operating problems in the U.K.

Sales revenues from petroleum products increased in 1999 due to higher prices and increased international and marine fuels volumes. Our 1999 natural gas volumes decreased in the U.S. due to lower production and reduced sales of purchased gas. Internationally, our results were impacted by our withdrawal from the U.K. retail gas market.

Other Revenues

Other revenues include our equity in the income of affiliates, gains from asset sales and interest income. Results for 2000 were higher due to increased equity in income of affiliates. These results benefited from improved refining margins for Motiva in the U.S. East and Gulf Coast areas and higher crude oil prices in our Indonesian producing affiliate. Adversely impacting results were lower marketing and lubricant margins realized by Equilon and lower Caltex marketing results.

Results for 1999 were lower due to reduced interest income on notes and marketable securities and lower asset sales. Equity in income of affiliates in 1999 was consistent with 1998. Lower downstream margins in the Caltex Asia-Pacific region and in Motiva's East and

Gulf Coast areas depressed results. However, we realized higher refining margins in Equilon's West Coast operating areas. We also benefited from stronger crude oil prices in our Indonesian producing affiliate during the second half of 1999.

Our share of special charges by our affiliates included in other revenues amounted to $104 million in 2000, $153 million in 1999 and $159 million in 1998. In 2000, these major special charges included a loss on the sale of a U.S. refinery and asset write-downs, as well as patent litigation and environmental issues. Also included was a special gain for an employee benefits revision. The 1999 special charges included refinery asset write-downs in the U.S. and a loss on the sale of an interest in a Japanese affiliate. These charges were reduced by inventory valuation benefits in the U.S. and abroad, as well as tax revaluation benefits in Korea.

In 1998, special charges included inventory valuation adjustments, net U.S. alliance formation costs and Caltex restructuring charges.

Costs and Expenses

Costs and expenses from operations were $46.3 billion in 2000, $33.3 billion in 1999 and $30.5 billion in 1998. Significantly higher worldwide crude oil, petroleum products and U.S. natural gas prices increased our purchases and other costs in 2000. Operating expenses also increased due to the impact of higher fuel and gas prices on utility expenses and production taxes. In 1999, our purchases and other costs increased due to higher prices and product volumes.

Special items recorded by our subsidiaries increased costs and operating expenses by $819 million in 2000, $121 million in 1999 and $382 million in 1998. Major special items in 2000 included asset write-downs, losses on asset sales and environmental and litigation issues. The asset write-downs and losses on asset sales in 2000, which increased depreciation, depletion and amortization expense by $569 million, resulted mainly from impairments of certain producing properties and refinery assets in Panama, as well as sales of producing assets. In 1999 and 1998, write-downs and losses on asset sales were recorded that increased depreciation, depletion and amortization expense by $87 million and $150 million. Asset impairments we have recognized are based on the provisions of SFAS 121, as well as other applicable accounting pronouncements. These impairments are driven by specific events, including the sale of properties or downward revisions in underground reserve quantities. In performing our reviews of assets not held for sale, we use our best judgment in estimating future cash flows. This includes our outlook for commodity prices based on our review of supply and demand forecasts and other economic indicators.

Special items in 1999 also included inventory valuation benefits in subsidiaries, which reversed charges recorded in 1998 when commodity prices were very depressed. The year 1998 also included employee separation costs.

Interest expense for 2000 was lower due to lower debt levels and higher capitalized interest on major upstream projects. The amount recorded for 1999 reflects the impact of higher average debt levels.

Income Taxes

Income tax expense was $1,676 million in 2000, $602 million in 1999 and $98 million in 1998. The increases in 2000 and 1999 are the result of higher income from producing operations due to higher prices.

Income Summary Schedules

The following schedules show after-tax results before and after special items and before the cumulative effect of accounting change. A full discussion of special items is included in our Analysis of Income by Operating Segments.

Income (Loss)

(Millions of dollars)	**2000**	1999	1998
Income before special items and cumulative effect of accounting change	**$ 2,898**	$ 1,214	$ 894
Special items:			
Write-downs of assets	**(272)**	(157)	(93)
Environmental, litigation and royalty issues	**(138)**	(42)	—
Gains (losses) on major asset sales	**(94)**	(62)	20
Reorganization, restructuring, employee related and other costs	**(8)**	(74)	(144)
Tax issues	**96**	106	25
Tax benefits on asset sales	**70**	40	43
Inventory valuation adjustments	**—**	152	(142)
Merger costs	**(10)**	—	—
Total special items	**(356)**	(37)	(291)
Income before cumulative effect of accounting change	**$ 2,542**	$ 1,177	$ 603

The following schedule further details our results:

Income (Loss)

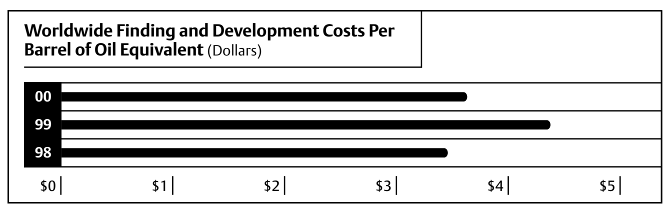
	Before Special Items			After Special Items		
(Millions of dollars)	**2000**	1999	1998	**2000**	1999	1998
Exploration and production (upstream)						
United States	**$ 1,788**	$ 666	$ 381	**$ 1,518**	$ 652	$ 301
International	**1,058**	386	181	**1,077**	360	129
Total	**2,846**	1,052	562	**2,595**	1,012	430
Refining, marketing and distribution (downstream)						
United States	**243**	287	276	**158**	208	221
International	**272**	338	503	**143**	370	332
Total	**515**	625	779	**301**	578	553
Global gas, power and energy technology	**50**	21	(33)	**50**	(14)	(16)
Total	**3,411**	1,698	1,308	**2,946**	1,576	967
Other business units	**(11)**	(3)	(2)	**(11)**	(3)	(2)
Corporate/Non-operating	**(502)**	(481)	(412)	**(393)**	(396)	(362)
Income before cumulative effect of accounting change	**$ 2,898**	$ 1,214	$ 894	**$ 2,542**	$ 1,177	$ 603

ANALYSIS OF INCOME BY OPERATING SEGMENTS

Upstream

In our upstream business, we explore for, find, develop, produce and sell crude oil, NGL and natural gas.

Our upstream operations benefited from sharply higher crude oil and natural gas prices during 2000. The following discussion focuses on how the price environment and other business factors affected our earnings. The U.S. results for 1998 include some minor Canadian operations which were sold at the end of 1998.



Our finding and development costs remain at competitive levels.

United States Upstream

(Millions of dollars, except as indicated)	**2000**	1999	1998
Operating income before special items	**$ 1,788**	$ 666	$ 381
Special items:			
Write-downs of assets	**(126)**	—	(51)
Environmental, litigation and royalty issues	**(15)**	(30)	—
Gains (losses) on major asset sales	**(129)**	18	—
Reorganization, restructuring, employee related and other costs	**—**	(11)	(29)
Tax issues	**—**	9	—
Total special items	**(270)**	(14)	(80)
Operating income	**$ 1,518**	$ 652	$ 301
Selected operating data:			
Net production			
Crude oil and NGL *(thousands of barrels a day)*	**356**	395	433
Natural gas available for sale *(millions of cubic feet a day)*	**1,310**	1,462	1,679
Average realized crude price *(dollars per barrel)*	**$ 26.00**	$ 14.70	$ 10.60
Average realized natural gas price *(dollars per MCF)*	**$ 3.69**	$ 2.18	$ 2.00
Exploratory expenses *(millions of dollars)*	**$ 120**	$ 234	$ 257
Lifting costs *(dollars per barrel of oil equivalent)*	**$ 5.05**	$ 4.01	$ 4.07
Return on average capital employed before special items	**29.0%**	10.5%	6.0%
Return on average capital employed	**24.6%**	10.3%	4.7%

WHAT HAPPENED IN THE UNITED STATES?

Business Factors

PRICES We benefited from higher prices in 2000, which improved earnings by $1,368 million. Our average realized crude oil price increased by 77% to $26.00 per barrel. This follows a 39% increase in 1999. Despite production increases in 2000 by OPEC members, concerns over low global inventories of crude oil and refined products helped push prices up to their highest levels since the Gulf War in 1991. Concerns over low U.S. natural gas storage levels and strong demand helped push U.S. natural gas prices to record levels. Our average realized natural gas price in 2000 increased 69% to $3.69 per thousand cubic feet (MCF). This follows a 9% increase in 1999.

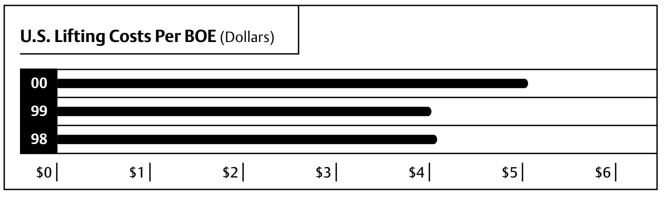
OUR U.S. AVERAGE REALIZED CRUDE OIL PRICE IN 2000 WAS $26.00, AN INCREASE OF 77%.

PRODUCTION Our production decreased by 10% in 2000. Half of this expected reduction was due to our continuing strategy of selling non-core producing properties. In 1999, we decided to divest non-strategic assets and focus investment on high-return, high-impact opportunities. The balance of the decrease was due to natural field declines, which exceeded new production from various fields. In 1999, our production also decreased by 10% due to natural field declines, asset sales and reduced investment in mature properties.

EXPLORATORY EXPENSES We expensed $120 million on exploratory activity in 2000. Our exploratory expenses in 1999 were $234 million, 9% lower than in 1998. The year 1999 included a $100 million write-off of investments in prospects in the Gulf of Mexico. These prospects, initially drilled between 1995 and 1998, were determined to be non-commercial in the fourth quarter of 1999 after further appraisal drilling.

Other Factors

Our operating expenses increased by 7% in 2000. This was the result of higher crude oil and natural gas prices causing a significant increase in utilities expense and production taxes. Our lifting costs per barrel of oil equivalent (BOE) increased in 2000 due to these factors. In 1999, our lifting costs per BOE benefited from cost savings offset partly by lower production.



The increase in our lifting costs in 2000 reflects the effect of sharply higher oil and gas prices on utility expenses and production taxes.

Special Items

In 2000, our results included a $129 million charge for net losses on the sales of non-core producing properties and related disposal costs. These sales were a significant part of our continuing strategy to upgrade our portfolio in the upstream by divesting non-strategic assets and focusing investment on high-return, high-impact opportunities. Our results also included a special charge of $15 million for crude oil and gas royalty settlements and $126 million for the write-downs of assets, mostly in the Gulf of Mexico and Gulf Coast. These impairments were caused by downward revisions in the fourth quarter of 2000 of the estimated volume of the fields' proved reserves and changes in our outlook of future production. We determined that the carrying values of these properties exceeded future undiscounted cash flows. Fair value was determined by discounting expected future cash flows.

Our results for 1999 included a $30 million charge for the settlement of crude oil royalty valuation issues on federal lands and an $11 million charge for employee separation costs. The employee separation costs result from the expansion of our 1998 program. Results for 1998 included a charge for employee separation costs of $29 million. See the section entitled Reorganizations, Restructurings and Employee Separation Programs on page 40 for additional information. During 1999, we also recorded an $18 million gain on asset sales in California and a $9 million production tax refund.

Results for 1998 also included asset write-downs of $51 million for impaired properties in Louisiana and Canada. The impaired Louisiana property represents an unsuccessful enhanced recovery project, which we determined to be impaired in the fourth quarter of 1998. The Canadian properties were impaired following our decision in October 1998 to exit the upstream business in Canada. These properties were written down to their sales price with the sale closing in December 1998.

International Upstream

(Millions of dollars, except as indicated)	**2000**	1999	1998
Operating income before special items	**$ 1,058**	$ 386	$ 181
Special items:			
Write-downs of assets	**(20)**	—	(42)
Gains on major asset sales	**90**	—	—
Reorganization, restructuring, employee related and other costs	**(14)**	(2)	(10)
Tax issues	**(37)**	(24)	—
Total special items	**19**	(26)	(52)
Operating income	**$ 1,077**	$ 360	$ 129
Selected operating data:			
Net production			
Crude oil and NGL *(thousands of barrels a day)*	**444**	490	497
Natural gas available for sale *(millions of cubic feet a day)*	**557**	537	548
Average realized crude price *(dollars per barrel)*	**$ 24.83**	$ 15.23	$ 11.20
Average realized natural gas price *(dollars per MCF)*	**$ 1.58**	$ 1.34	$ 1.63
Exploratory expenses *(millions of dollars)*	**$ 238**	$ 267	$ 204
Lifting costs *(dollars per barrel of oil equivalent)*	**$ 4.09**	$ 4.37	$ 3.74
Return on average capital employed before special items	**23.2%**	10.3%	5.8%
Return on average capital employed	**23.6%**	9.6%	4.1%

WHAT HAPPENED IN THE INTERNATIONAL AREAS?

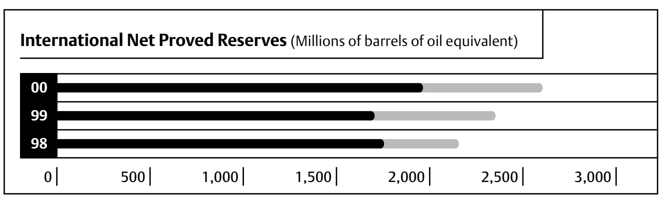
Business Factors

PRICES Our earnings increased by $720 million in 2000 due to sharply higher crude oil and natural gas prices. Our average crude oil price increased by 63% to $24.83 per barrel. Market conditions kept crude oil prices strong throughout 2000 despite OPEC actions to boost production. Crude oil prices began to improve in 1999, increasing by 36% to $15.23 per barrel. This was due to worldwide production cutbacks and improved demand. Our average realized natural gas price increased by 18% in 2000 to $1.58 per MCF. This follows a decrease of 18% in 1999.

OUR INTERNATIONAL AVERAGE CRUDE OIL PRICE IN 2000 WAS $24.83 PER BARREL, AN INCREASE OF 63%.

PRODUCTION Our production in 2000 declined by 7%. We experienced some declines due to scheduled maintenance and repairs in our U.K. North Sea operations. In Indonesia, we had lower production volumes as higher prices reduced our lifting entitlements for cost recovery under a production sharing agreement. In addition, the planned sale of non-core producing properties caused 40% of the production decline. These declines were partially offset by increased production in the Partitioned Neutral Zone and the Karachaganak field in the Republic of Kazakhstan. Our production decreased slightly in 1999 due to operating problems in the U.K. North Sea and reduced lifting entitlements in Indonesia. We also experienced lower natural gas production in Latin America. These declines were partially offset by increased production in the Partitioned Neutral Zone as a result of increased drilling activity and development of the Karachaganak field in Kazakhstan.

EXPLORATORY EXPENSES Our exploratory expenses for 2000 were $238 million. We expensed $267 million on exploratory activity in 1999, an increase of 31%. This included about $50 million for an unsuccessful exploratory well offshore Trinidad and $30 million for prior year drilling expenditures in Thailand, which we wrote off in 1999 after we determined the prospect to be non-commercial.

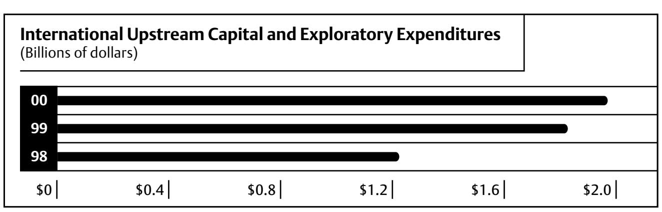


Net proved reserves increased in 2000 due to the Hamaca project in Venezuela.

■ Crude Oil ■ Natural Gas

Other Factors

Our operating expenses decreased 7% in 2000 in line with production declines. Our lifting costs in 2000 were $4.09 per BOE, a decrease of 6%. This decrease was due in part to lower U.K. lifting costs. Lifting costs per BOE increased in 1999 by 17%, primarily resulting from lower Indonesian lifting entitlements.



The growth in international upstream investments shows our focus on high-impact projects.

Special Items

Our results for 2000 included a special benefit of $90 million for net gains on the sales of non-core producing properties. These sales are part of our continuing strategy to divest non-strategic assets and focus investment on high-return, high-impact opportunities. Results for 2000 also included a special charge of $14 million for net losses resulting from the Erskine pipeline interruption in the U.K. North Sea, charges of $37 million for prior years' tax adjustments and a fourth quarter charge of $20 million for an asset write-down associated with a project in the U.K. North Sea, which we do not plan to develop.

Our results for 1999 included a $24 million charge for prior years' tax issues in the U.K. and a $2 million charge for employee separation costs. The employee separation costs result from the expansion of our 1998 program. Results for 1998 included a charge for employee separation costs of $10 million. See the section entitled Reorganizations, Restructurings and Employee Separation Programs on page 40 for additional information.

Results for 1998 also included a write-down of $42 million for the impairment of our investment in the Strathspey field in the U.K. North Sea. The Strathspey impairment was caused by a downward revision in the fourth quarter of 1998 of the estimated volume of the field's proved reserves.

LOOKING FORWARD IN THE WORLDWIDE UPSTREAM

We intend to continue to cost-effectively explore for, develop and produce crude oil and natural gas reserves by focusing on high-margin, high-impact projects. We will continue to review our assets for profitability and strategic fit and make selective dispositions, as appropriate. We expect worldwide production to grow an average of two to three percent annually over the next five years. Our growth areas of focus include:

- Philippines — where we hold a 45% interest in the Malampaya Deep Water Natural Gas Project, with first production expected by early 2002
- West Africa — where we will develop the major Agbami oil field offshore Nigeria
- U.S. Gulf of Mexico — where we hold both exploration and production acreage and saw the July 2000 start-up of our Petronius Project
- U.K. North Sea — where first production from the second phase (Area B) of the Captain field began in December 2000
- Venezuela — where we have a 30% interest in the Hamaca Oil Project, which is under development
- Kazakhstan — where we hold interests in the Karachaganak and North Buzachi projects
- Brazil — where we have interests in both exploration and development areas

Downstream

In our downstream business, we refine, transport and sell crude oil and products, such as gasoline, fuel oil and lubricants.

Our U.S. downstream includes our share of operations in Equilon and Motiva. Equilon is our joint venture with Shell Oil Company in which we have a 44% interest. The Equilon area includes western and midwestern refining and marketing operations and nationwide trading, transportation and lubricants activities. The Motiva area includes East and Gulf Coast refining and marketing operations. Our results for 2000, 1999 and the last half of 1998 are our share of the earnings of Motiva, our joint venture with Shell and Saudi Refining, Inc., which began operations on July 1, 1998. In accordance with contractual provisions, our ownership interest in Motiva is subject to change. From the start of operations through December 31, 1999 our ownership interest was 32.5%. For the year 2000, our interest was just under 31%. Results for the first half of 1998 are for our 50% share of Star, our joint venture with Saudi Refining, Inc.

Internationally, our wholly-owned downstream operations are reported separately as Latin America and West Africa and Europe. We also have a 50% interest in Caltex, a joint venture with Chevron, which operates in Africa, Asia, Australia, the Middle East and New Zealand.

In the U.S. and international operations, we also have other businesses, which include aviation and marine product sales, lubricants marketing and other refined product trading activity.

United States Downstream

(Millions of dollars, except as indicated)	**2000**	1999	1998
Operating income before special items	**$ 243**	$ 287	$ 276
Special items:			
Write-downs of assets	**(10)**	(76)	—
Environmental, litigation and royalty issues	**(45)**	—	—
Losses on major asset sales	**(48)**	—	—
Reorganization, restructuring, employee related and other costs	**18**	(11)	(21)
Inventory valuation adjustments	**—**	8	(34)
Total special items	**(85)**	(79)	(55)
Operating income	**$ 158**	$ 208	$ 221
Selected operating data:			
Refinery input *(thousands of barrels a day)*	**524**	671	698
Refined product sales *(thousands of barrels a day)*	**1,373**	1,347	1,203
Return on average capital employed before special items	**9.9%**	11.3%	9.6%
Return on average capital employed	**6.4%**	8.2%	7.7%

WHAT HAPPENED IN THE UNITED STATES?

Equilon Area

These operations contributed $151 million to our 2000 operating earnings before special items. Our earnings were lower in 2000 as a result of depressed marketing margins as pump prices lagged increases in supply costs in a highly competitive market. Additionally, weak lubricant margins resulting from higher base oil costs negatively impacted earnings. Maintenance activity at the Puget Sound, Martinez and Wood River refineries also contributed to these lower results. These negative factors were partly offset by higher refining margins.

We achieved higher earnings in 1999 from improved West Coast refining margins as a result of industry refinery outages earlier in the year. We also benefited from improved utilization of the Martinez refinery, transportation results and higher trading activity volumes. These improved results were partly offset by operating problems at the Puget Sound refinery early in the year and weak marketing margins.

Motiva Area

These operations contributed $102 million of our 2000 operating income before special items. Our earnings were higher in 2000 due to improved East and Gulf Coast refining margins stemming from lower industry inventory levels. The year began with low inventory stocks and tight supplies continued throughout the year due to increased demand, industry refinery downtime and unusually cold weather. These improved results were negatively impacted by maintenance activity early in 2000 at the Delaware City and Port Arthur refineries.

Results for 1999 were lower due to weak refining and marketing margins on the East and Gulf Coasts. This weakness resulted from the inability to pass along rising supply costs and from high industry-wide refined product inventory levels. These negative factors were partly offset by improved refinery reliability.

Special Items

Results for 2000, 1999 and 1998 included net special charges of $85 million, $79 million and $55 million, representing our share of special items recorded by our U.S. alliances.

The 2000 charge included $48 million for the loss on the sale of the Wood River refinery. This sale was completed in June to Tosco Corporation. Our 2000 results also included charges of $10 million for asset write-downs and $45 million for environmental, litigation and royalty issues, as well as a benefit of $18 million for an employee benefits revision.

The 1999 charge included $76 million for the write-downs of assets to their estimated sales values by Equilon for the intended sales of its El Dorado and Wood River refineries. Equilon completed the sale of the El Dorado refinery to Frontier Oil Corporation in November 1999.

Our 1999 results also included an inventory valuation benefit of $8 million due to higher 1999 inventory values. This follows a 1998 charge of $34 million to reflect lower market prices on December 31, 1998 for inventories of crude oil and refined products. We value inventories at the lower of cost or market after initially recording at cost. Inventory valuation adjustments are reversed when prices recover and the associated physical units of inventory are sold.

Our 1999 and 1998 results included net charges of $11 million and $21 million for reorganizations, restructurings and employee separation costs. The 1999 charge represents dismantling expenses at a closed refinery, an adjustment to the Anacortes refinery sale and employee separation costs from the expansion of Equilon's and Motiva's 1998 separation programs. The 1998 net charge was for U.S. alliance formation issues. This net charge included $52 million for employee separation costs and $45 million for write-downs of closed facilities and surplus equipment to their net realizable value. These facilities included a refinery in Texas, lubricant plants in various states, a sales terminal in Louisiana, and research facilities and equipment in Texas and New York. Also included in net charges were gains of $76 million from the Federal Trade Commission mandated sale of the Anacortes refinery and Plantation pipeline.

International Downstream

(Millions of dollars, except as indicated)	**2000**	1999	1998
Operating income before special items	**$ 272**	$ 338	$ 503
Special items:			
Write-downs of assets	**(112)**	(23)	—
Environmental, litigation and royalty issues	**(5)**	—	—
Losses on major asset sales	**—**	(80)	—
Reorganization, restructuring, employee related and other costs	**(12)**	(41)	(63)
Tax issues	**—**	32	—
Inventory valuation adjustments	**—**	144	(108)
Total special items	**(129)**	32	(171)
Operating income	**$ 143**	$ 370	$ 332
Selected operating data:			
Refinery input *(thousands of barrels a day)*	**794**	820	832
Refined product sales *(thousands of barrels a day)*	**1,752**	1,789	1,685
Return on average capital employed before special items	**4.4%**	5.6%	8.2%
Return on average capital employed	**2.3%**	6.1%	5.4%

WHAT HAPPENED IN THE INTERNATIONAL AREAS?

Latin America and West Africa

Our operations in Latin America and West Africa contributed $141 million to our 2000 operating income before special items. Results for 2000 decreased due to lower refining margins as escalating crude costs continued to outpace product price increases in Panama and Guatemala. Rising utility costs and downtime also negatively impacted refining results. Contributing to the decrease were lower marketing margins and volumes in South America and lower margins in Central America and West Africa.

Our 1999 earnings declined due to lower refining margins arising from higher crude costs. Lower marketing margins and lower volumes in Brazil also depressed earnings, but were partially offset by higher refined product sales in our Caribbean and Central American operations.

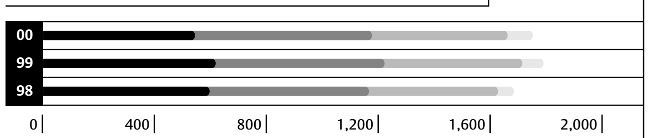
Europe
Our European operations contributed $161 million to our 2000 operating income before special items. We achieved higher earnings in 2000 from improved refining margins in the U.K. and the Netherlands. These improvements were partially offset by higher utility costs. Also, results were negatively impacted by lower marketing margins in Europe, as well as higher expenses in the U.K.

Our 1999 results were lower due to poor refining margins as product price increases failed to keep pace with escalating crude costs. Increased refined product sales helped to offset the squeeze on margins.

Caltex
We recognized a loss of $24 million before special items in 2000 from our Caltex operations. Earnings declined in 2000 due to depressed marketing margins. This reflected the inability to recover rapidly increasing crude oil costs in highly competitive markets. Lower refined product volumes also contributed to the decrease. Although marketing results declined, refining margins improved for the year.

In 1999, our results were adversely impacted by lower refining and marketing margins. These declines were partially offset by an inventory drawdown benefit, lower currency losses and gains on the sales of marketable securities.

International Refined Product Sales (Thousands of barrels a day)



International sales volumes held steady in 2000.

■ Caltex area ■ Europe ■ Latin America/West Africa ■ Other areas

Special Items
Results for 2000 included net special charges of $112 million, primarily related to the write-down of the Panama refinery. We determined that the carrying value of the refinery exceeded undiscounted future cash flows. The impairment of the entire carrying value of the refinery was caused by a final determination in the fourth quarter of 2000 that the unfavorable operating environment and severe downward pressure on profit margins would not improve in the foreseeable future. Our 2000 results also included special charges of $12 million related to employee separation costs and $5 million for environmental issues. See the section entitled Reorganizations, Restructurings and Employee Separation Programs on page 40 for additional information. Results for 1999 included net special benefits of $32 million, while 1998 included net special charges of $171 million. Special items relating to Caltex represent our 50% share.

Results for 1999 included inventory valuation benefits of $144 million due to higher 1999 inventory values. This follows a 1998 charge of $108 million to reflect lower market prices on December 31, 1998 for inventories of crude oil and refined products, as well as additional charges recorded in prior years. We value inventories at the lower of cost or market, after initially recording at cost. Inventory valuation adjustments are reversed when prices recover and the associated physical units of inventory are sold.

Results for 1999 included a charge of $23 million for the write-downs of assets. These write-downs on properties to be disposed of include $10 million for marketing assets in our subsidiary in Poland and $13 million for assets in our Caltex operations.

Our 1999 results included a $9 million charge for employee separation costs for our subsidiaries operating in Europe and Latin America. These costs resulted from the expansion of our 1998 program. Results for 1998 included a charge for employee separation costs of $20 million. See the section entitled Reorganizations, Restructurings and Employee Separation Programs on page 40 for additional information.

Results for 1999 also included charges of $80 million related to our share of the Caltex loss on the sale of its equity interest in Koa Oil Company, Limited, including deferred currency translation net losses. Additionally, our results for 1999 included a Caltex Korean tax benefit of $54 million due to asset revaluation and $22 million for prior year tax charges in the U.K.

Results for 1999 and 1998 included other charges of $32 million and $43 million, representing our share of a Caltex reorganization program. The 1999 charge represented continued expenses related to the 1998 program. The 1998 charge resulted from its decision to structure the organization along functional lines and to reduce costs by establishing a shared service center in the Philippines. In implementing this change, Caltex also relocated its headquarters from Dallas to Singapore. About $35 million of the 1998 charge relates to severance and other retirement benefits for about 200 employees not relocating, write-downs of surplus furniture and equipment, and other costs. The balance of the charge is for severance costs in other affected areas and amounts spent in relocating employees to the new shared service center.

LOOKING FORWARD IN THE WORLDWIDE DOWNSTREAM
We intend to do the following in our worldwide downstream:

- Pursue marketing growth opportunities in selected areas
- Continue to focus on lowering costs
- Focus on business opportunities in areas of trading, transportation and lubricants

Global Gas, Power and Energy Technology

(Millions of dollars, except as indicated)	**2000**	1999	1998
Operating income (loss) before special items	**$ 50**	$ 21	$ (33)
Special items:			
Write-downs of assets	—	(32)	—
Gain on major asset sale	—	—	20
Reorganization, restructuring, employee related and other costs	—	(3)	(3)
Total special items	—	(35)	17
Operating income (loss)	**$ 50**	$ (14)	$ (16)
Natural gas sales *(millions of cubic feet per day)*	**3,476**	3,134	3,764
Net power sales *(gigawatt hours)*	**5,644**	4,353	4,395

Global gas, power and energy technology includes marketing of natural gas and natural gas liquids, gas processing plants, pipelines, power generation plants, gasification licensing and equity plants, fuel processing, hydrocarbons-to-liquids, hydrogen storage systems and fuel cell technology units. Gasification is a proprietary technology that converts low-value hydrocarbons into useful synthesis gas for the chemical, refining and power industries. In 2000, we purchased a 20% interest in Energy Conversion Devices, Inc. (ECD). ECD develops and commercializes enabling technologies for use in the fields of energy storage and information technology. We formed two joint ventures with ECD, to further develop and commercialize fuel cells and hydrogen storage products. We also formed a joint venture with a subsidiary of Enron Corp. that combined the companies' intrastate pipeline and storage businesses in south Louisiana.

Our gas marketing and trading results in 2000 benefited from improved natural gas liquids and natural gas margins.

Our gas marketing operating results in 1999 benefited from improved natural gas liquids margins. Also included in our 1999 results are gains on normal asset sales and lower operating expenses. The asset sales included our interest in a U.K. retail gas marketing operation and the sale of a U.S. gas gathering pipeline.

Our operating results for the power and gasification business in 2000 were slightly higher than 1999.

Our 1999 results benefited from higher gasification licensing revenues, cogeneration income and the start-up of new plants in Thailand and Indonesia. This was partially offset by the non-recurring recoupment of development costs in 1998.

Special Items

Results for both 1999 and 1998 included charges of $3 million for employee separation costs. The 1999 charge resulted from the expansion of our 1998 program. See the section entitled Reorganizations, Restructurings and Employee Separation Programs on page 40 for additional information.

Our 1999 results also included charges of $32 million for asset write-downs from the impairment of certain gas plants in Louisiana. We determined in the fourth quarter of 1999 that as a result of declining gas volumes available for processing, the carrying value of these plants exceeded future undiscounted cash flows. Fair value was determined by discounting expected future cash flows. Our 1998 results also included a gain of $20 million on the sale of an interest in our Discovery pipeline affiliate.

LOOKING FORWARD IN GLOBAL GAS, POWER AND ENERGY TECHNOLOGY

We believe there is great promise with emerging energy technologies. Accordingly, we are pursuing opportunities utilizing gasification, hydrocarbons-to-liquids and fuel cell technologies. We continue to develop power projects in conjunction with our exploration, production and refining needs. Our future plans include:

- Developing power projects where significant reserves of natural gas require commercialization
- Expanding our gasification technology to commercialize this environmentally friendly technology
- Using our technology to develop opportunities in the fuel cell, fuel processing, hydrogen storage and hydrocarbons-to-liquids businesses

Other Business Units

(Millions of dollars)	**2000**	1999	1998
Operating loss	**$ (11)**	$ (3)	$ (2)

Our other business units mainly include our insurance operations. There were no significant items in our three-year results.

Corporate/Non-operating

(Millions of dollars)	**2000**	1999	1998
Results before special items	**$ (502)**	$ (481)	$ (412)
Special items:			
Write-downs of assets	**(4)**	(26)	—
Environmental, litigation and royalty issues	**(73)**	(12)	—
Loss on major asset sales	**(7)**	—	—
Reorganization, restructuring, employee related and other costs	—	(6)	(18)
Tax issues	**133**	89	25
Tax benefits on asset sales	**70**	40	43
Merger costs	**(10)**	—	—
Total special items	**109**	85	50
Total Corporate/Non-operating	**$ (393)**	$ (396)	$ (362)

Corporate/Non-operating includes our corporate center and financing activities. Our 2000 results included lower interest and higher corporate expenses. The increase in corporate expenses included spending for our Olympic sponsorship program and increased incentive compensation for employees associated with the higher level of earnings. Results for 1999 included higher interest expense resulting from increases in debt levels.

Special Items

Results for 2000 included a tax benefit of $133 million for favorable income tax settlements and adjustments to prior years' tax liabilities and tax benefits of $70 million on the sale of an interest in a subsidiary. Also included are charges of $73 million for environmental and litigation issues, $10 million for merger costs, $7 million for early extinguishment of debt associated with the sale of a U.K. North Sea offshore producing field and $4 million for write-downs of assets.

Results for 1999 included tax benefits of $89 million. These are associated with favorable determinations in the fourth quarter on prior years' tax issues. Results for 1999 and 1998 included tax benefits of $40 million and $43 million from the sales of interests in a subsidiary. Additionally, results for 1998 included a benefit of $25 million to adjust for prior years' federal tax liabilities.

Our 1999 results also included a $6 million charge for employee separation costs. These costs resulted from the expansion of our 1998 program. Results for 1998 included a charge for employee separations of $18 million. See the section entitled Reorganizations, Restructurings and Employee Separation Programs on page 40 for additional information.

We also recorded in 1999 charges of $12 million for environmental issues and $26 million for the impairment of assets and related disposal costs. The assets write-downs resulted from our joint plan with state and local agencies to convert for third-party industrial use idle facilities formerly used in research activities. The facilities and equipment were written down to their appraised values.

OTHER ITEMS

Liquidity and Capital Resources

INTRODUCTION The Consolidated Statement of Cash Flows on page 51 reports the changes in cash balances for the last three years, and summarizes the inflows and outflows of cash between operating, investing and financing activities. Our cash requirements are met by cash from operations and the proceeds from the sale of non-strategic assets, supplemented by outside borrowings and sales of investment instruments, if needed.

INFLOWS *Cash from operating activities* represents net income adjusted for non-cash charges or credits, such as depreciation, depletion and amortization, and changes in working capital and other balances. Operating cash flows for 2000 of $3,864 million benefited mainly from higher crude oil and natural gas prices partially offset by lower crude oil and natural gas production. For more detailed insight into our financial and operational results, see Analysis of Income by Operating Segments on the preceding pages.

Other cash inflows in 2000 represent the proceeds from asset sales of $684 million, mainly of non-strategic assets. As discussed earlier, these assets are producing properties that no longer fit our business strategy of focusing on high-margin, high-impact projects.

OUTFLOWS *Capital expenditures* were $2,974 million in 2000. The section on page 41 describes in more detail our capital and exploratory spending.

Net borrowings in 2000 decreased by $444 million compared to a net increase of $290 million in 1999. This year's decrease reflects debt repayments of $2,167 million and increased borrowings of $1,723 million which includes the issuance of $530 million of medium-term notes. During the year, we increased commercial paper by $340 million to $1,439 million. See Note 9 to the financial statements for total outstanding debt, including 2000 borrowings.

WE MAINTAIN STRONG CREDIT RATINGS AND ACCESS TO GLOBAL FINANCIAL MARKETS PROVIDING US FLEXIBILITY TO BORROW FUNDS AT LOW CAPITAL COSTS.

Our senior debt is rated A+ by Standard & Poor's Corporation and A1 by Moody's Investors Services. Our U.S. commercial paper is rated A-1 by Standard & Poor's and Prime-1 by Moody's. These ratings denote high-quality investment grade securities. Our debt has an average maturity of 10 years and a weighted average interest rate of 6.9%. We increased our revolving credit facilities to $2.575 billion at December 31, 2000 from $2.05 billion at years ended 1999 and 1998. These facilities remain unused and provide liquidity and support our commercial paper program.

Payments of dividends were $1,116 million in 2000: $976 million to common, $15 million to preferred and $125 million to shareholders who hold a minority interest in Texaco subsidiary companies.

Purchases of common stock were $169 million in 2000. In March of 2000, we resumed purchasing common stock under the $1 billion common stock repurchase program we initiated in early 1998. Including the purchases of $169 million in 2000, this brings our total purchases under this program, including $474 million purchased in 1998, to $643 million. No shares were repurchased in 1999. We suspended the repurchase program following the October 2000 announcement of the proposed merger with Chevron Corporation.

Other cash outflows in 2000 reflect the net purchases of investment instruments of $61 million.

The following year-end table reflects our key financial indicators:

(Millions of dollars, except as indicated)	**2000**	1999	1998
Current ratio	**1.18**	1.05	1.07
Total debt	**$ 7,191**	$ 7,647	$ 7,291
Average years debt maturity	**10**	10	10
Average interest rates	**6.9%**	7.0%	7.0%
Minority interest in subsidiary companies	**$ 713**	$ 710	$ 679
Stockholders' equity	**$ 13,444**	$ 12,042	$ 11,833
Total debt to total borrowed and invested capital	**33.7%**	37.5%	36.8%

OUTLOOK We consider our financial position to be sufficiently strong to meet our anticipated future requirements. Our financial policies and procedures afford us flexibility to meet the changing landscape of our financial environment. Cash required to service debt maturities in 2001 is projected to be $585 million. However, we intend to refinance these maturities.

In 2001, we feel our *cash from operating activities,* coupled with our *borrowing* capacity, will allow us to meet our *Capex program* and the payment of *dividends*.

MANAGING MARKET RISK We are exposed to the following types of market risks:

- The price of crude oil, natural gas and petroleum products
- The value of foreign currencies in relation to the U.S. dollar
- Interest rates

We use contracts, such as futures, options and swaps, in managing our exposure to these risks. We have written policies that govern our use of these instruments and limit our exposure to market and counterparty risks. These arrangements do not expose us to material adverse effects. See Notes 9, 14 and 15 to the financial statements and Supplemental Market Risk Disclosures on page 79 for additional information.

Reorganizations, Restructurings and Employee Separation Programs

In the fourth quarter of 1998, we announced that we were reorganizing several of our operations and implementing other cost-cutting initiatives. The principal units affected were our worldwide upstream; our international downstream, principally our marketing operations in the United Kingdom and Brazil and our refining operations in Panama; global gas marketing, now included as part of our global gas, power and energy technology operating segment; and our corporate center. We accrued $115 million ($80 million, net of tax) for employee separations, curtailment costs and special termination benefits associated with these announced restructurings in the fourth quarter of 1998. During the second quarter of 1999, we expanded the employee separation programs and recorded an additional provision of $48 million ($31 million, net of tax). For the most part, separation accruals are shown as operating expenses in the Consolidated Statement of Income.

The following table identifies each of our four restructuring initiatives. It provides the provision recorded in the fourth quarter of 1998 and the additional provision recorded in the second quarter of 1999. By the end of the third quarter of 2000, we had satisfied all remaining obligations in accordance with the plan provisions. Cash payments totaled $151 million, and transfers to long-term obligations totaled $12 million.

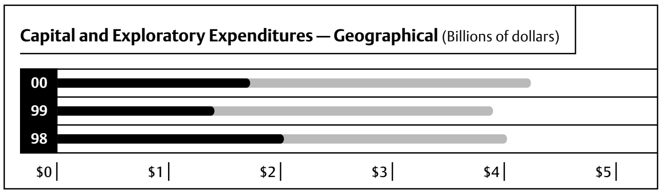
	Provision Recorded in	
(Millions of dollars)	1998	1999
Worldwide upstream	$ 56	$ 20
International downstream	25	13
Global gas, power and energy technology	5	4
Corporate center	29	11
Total	$ 115	$ 48

At the time we initially announced these programs, we estimated that over 1,400 employee reductions would result. Employee reductions of 800 in worldwide upstream, 300 in international downstream, 100 in global gas, power and energy technology and 200 in our corporate center were expected. During the second quarter of 1999, we expanded the program by about 1,200 employees, made up of 600 employees in worldwide upstream, 250 employees in international downstream, 130 employees in global gas, power and energy technology and 200 employees in our corporate center. By the end of the third quarter of 2000, the estimated employee reductions were met.

During the first quarter of 2000, we announced an additional employee separation program for our international downstream, primarily our marketing operations in Brazil and Ireland. We accrued $17 million ($12 million, net of tax) for employee separations, curtailment costs and special termination benefits for about 200 employees. These separation accruals are included in selling, general and administrative expenses in the Consolidated Statement of Income. Through December 31, 2000, employee reductions totaled 159. The remaining reductions will occur by the end of the first quarter of 2001. During the year 2000, we made cash payments of $8 million and transfers to long-term obligations of $8 million. We will pay the remaining obligations of $1 million in future periods in accordance with plan provisions.

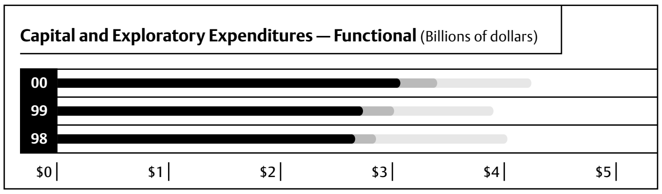
Capital and Exploratory Expenditures

2000 ACTIVITY Worldwide capital and exploratory expenditures, including our share of affiliates, were $4.2 billion for the year 2000, $3.9 billion for 1999 and $4.0 billion for 1998. Expenditures in 2000 included increased development work in upstream projects. Expenditures were geographically and functionally split as follows:



Our U.S. expenditures increased by almost 23% in 2000.

■ United States ■ International



We continued our emphasis on exploration and production projects, which was 72% of our spending.

■ Exploration and production ■ Refining, marketing, distribution and other ■ Global gas, power and energy technology

EXPLORATION AND PRODUCTION Significant areas of investment included:

- Exploration and development work in West Africa where we announced the major Agbami oil discovery offshore Nigeria in 1999
- Development of the Malampaya Deep Water Natural Gas Project in the Philippines
- Development work in Kazakhstan on the Karachaganak and North Buzachi fields
- Development work on the Captain B project in the U.K. North Sea
- Acquisition of EnerVest San Juan Acquisition Partnership in December 2000

OTHER Significant areas of investment included:

- Acquisition of a 20% interest in Energy Conversion Devices, Inc. in June 2000
- Development of the Thailand power project in which we have a 37.5% interest

The following table details our capital and exploratory expenditures:

(Millions of dollars)	2000 U.S.	2000 International	2000 Total	1999 U.S.	1999 International	1999 Total	1998 U.S.	1998 International	1998 Total
Exploration and production									
Exploratory expenses	**$ 120**	**$ 238**	**$ 358**	$ 234	$ 267	$ 501	$ 257	$ 204	$ 461
Capital expenditures	**968**	**1,729**	**2,697**	666	1,556	2,222	1,179	1,015	2,194
Total exploration and production	**1,088**	**1,967**	**3,055**	900	1,823	2,723	1,436	1,219	2,655
Refining, marketing and distribution	**405**	**380**	**785**	379	487	866	431	717	1,148
Global gas, power and energy technology	**164**	**169**	**333**	103	176	279	124	61	185
Other	**61**	**—**	**61**	18	7	25	29	2	31
Total	**$ 1,718**	**$ 2,516**	**$ 4,234**	$ 1,400	$ 2,493	$ 3,893	$ 2,020	$ 1,999	$ 4,019
Total, excluding affiliates	**$ 1,279**	**$ 2,210**	**$ 3,489**	$ 1,012	$ 2,051	$ 3,063	$ 1,528	$ 1,496	$ 3,024

2001

Spending for the year 2001 is expected to be $4.5 billion. In the upstream, spending continues to be allocated to our large-impact projects in West Africa, Venezuela, Kazakhstan, the Philippines and the North Sea. Major exploration programs are under way in our key focus areas of Nigeria, Brazil and the deepwater Gulf of Mexico. International marketing will increase spending in the U.K., Latin America and West Africa. Increases in spending are also anticipated for our international refinery system, particularly the Pembroke refinery in Wales. Our global gas, power and energy technology business continues to grow and has identified additional power generation and gasification projects and natural gas business opportunities. In addition, increased spending for our fuel cell and hydrogen storage joint ventures is anticipated.

Environmental Matters

The cost of compliance with federal, state and local environmental laws in the U.S. and international countries continues to be substantial. Using definitions and guidelines established by the American Petroleum Institute, our 2000 environmental spending was $686 million. This includes our equity share in the environmental expenditures of our major affiliates, Equilon, Motiva and the Caltex Group of Companies. The following table provides our environmental expenditures for the past three years:

(Millions of dollars)	**2000**	1999	1998
Capital expenditures	**$ 110**	$ 118	$ 175
Non-capital:			
Ongoing operations	**436**	391	495
Remediation	**109**	98	93
Restoration and abandonment	**31**	26	44
Total environmental expenditures	**$ 686**	$ 633	$ 807

CAPITAL EXPENDITURES

Our spending for capital projects in 2000 was $110 million. These expenditures were made to comply with clean air and water regulations as well as waste management requirements. Worldwide capital expenditures projected for 2001 and 2002 are $178 million and $154 million.

ONGOING OPERATIONS

In 2000, environmental expenses charged to current operations were $436 million. These expenses related largely to the production of cleaner-burning gasoline and the execution of our environmental programs.

REMEDIATION

Remediation Costs and Liabilities

Our worldwide remediation expenditures in 2000 were $109 million. This included $12 million spent on the remediation of Superfund waste sites. At the end of 2000, we had liabilities of $428 million for the estimated cost of our known environmental liabilities. This includes $41 million for the cleanup of Superfund waste sites. We have accrued for these remediation liabilities based on currently available facts, existing technology and presently enacted laws and regulations. It is not possible to project overall costs beyond amounts disclosed due to the uncertainty surrounding future developments in regulations or until new information becomes available.

Superfund Sites

Under the Comprehensive Environmental Response, Compensation and Liability Act, the U.S. Environmental Protection Agency (EPA) and other regulatory agencies have identified us as a potentially responsible party (PRP) for cleanup of Superfund waste sites. We have determined that we may have potential exposure, though limited in most cases, at 183 Superfund waste sites. Of these sites, 106 are on the EPA's National Priority List. Under Superfund, liability is joint and several. That is, each PRP at a site can be held liable individually for the entire cleanup cost of the site. We are, however, actively pursuing the sharing of Superfund costs with other identified PRPs. The sharing of these costs is on the basis of weight, volume and toxicity of the materials contributed by the PRP.

RESTORATION AND ABANDONMENT COSTS AND LIABILITIES

Expenditures in 2000 for restoration and abandonment of our oil and gas producing properties amounted to $31 million. At year-end 2000, accruals to cover the cost of restoration and abandonment were $749 million.

We make every reasonable effort to fully comply with applicable governmental regulations. Changes in these regulations, as well as our continuous re-evaluation of our environmental programs, may result in additional future costs. We believe that any mandated future costs would be recoverable in the marketplace since all companies within our industry would be facing similar requirements. However, we do not believe that such future costs would be material to our financial position or to our operating results over any reasonable period of time.

New Accounting Standards

In June 1998, the Financial Accounting Standards Board (FASB) issued SFAS 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS 133 establishes new accounting rules and disclosure requirements for most derivative instruments and hedge transactions. In June 1999, the FASB issued SFAS 137, which deferred the effective date of SFAS 133. This was followed in June 2000 by the issuance of SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities," which amended SFAS 133.

These standards require that all applicable derivative financial instruments be recorded in the Consolidated Balance Sheet at fair value. For derivatives accounted for as hedges, fair value adjustments are recorded to earnings or directly to equity, depending upon the type of hedge and the degree of hedge effectiveness. For hedges classified as fair value hedges, adjustments are also recorded to the carrying amount of the hedged item through earnings. For derivatives not accounted for as hedges, fair value adjustments are recorded to earnings.

We are adopting these standards effective January 1, 2001. The cumulative effects of adoption at that date on net income and other comprehensive income are not material to net income and stockholders' equity.

Euro Conversion

On January 1, 1999, 11 of the 15 member countries of the European Union established fixed conversion rates between their existing currencies and one common currency — the euro. The euro began trading on world currency exchanges at that time and may be used in business transactions. On January 1, 2002, new euro-denominated bills and coins will be issued, and legacy currencies will be completely withdrawn from circulation by June 30 of that year.

Prior to introduction of the euro, our operating subsidiaries affected by the euro conversion completed computer systems upgrades and fiscal and legal due diligence to ensure our euro readiness. Computer systems have been adapted to ensure that all our operating subsidiaries have the capability to comply with necessary business requirements and customer/supplier preferences. Legal due diligence was conducted to ensure post-euro continuity of contracts, and fiscal reviews were completed to ensure compatibility with our banking relationships. We, therefore, experienced no major impact on our current business operations as a result of the introduction of the euro. Our operating subsidiaries affected by the euro conversion are formulating plans to accommodate all euro-denominated transactions and triangulation conventions by January 1, 2002, and some of these operations have already implemented the utilization of the euro as a transactional currency.

We continue to review our marketing and operational policies and procedures to ensure our ability to continue to successfully conduct all aspects of our business in this new, price-transparent market. We believe that the euro conversion will not have a material adverse impact on our financial condition or results of operations.

California Power Situation

The electric utility deregulation plan adopted by the state of California in 1996 required utilities to dispose of a portion of their power generation assets. As a result, utilities that serve California purchase power on the open market and, in turn, sell power to the retail customers at capped rates. During the fourth quarter of 2000, California's power and gas markets experienced significant price volatility. Increased demand resulted in very high market prices that California utilities paid for power with no certainty they could recover these costs from their customers. As both supplier to and purchaser from the utility companies, Texaco has financial and operational exposure in California. While the possible outcomes for the California utility situation remain uncertain, we believe that they will not have a material adverse impact on our financial condition or results of operations.

Chevron-Texaco Merger

On October 15, 2000, Texaco and Chevron Corporation entered into a merger agreement. In the merger, Texaco shareholders will receive .77 shares of Chevron common stock for each share of Texaco common stock they own, and Chevron shareholders will retain their existing shares.

The new company — ChevronTexaco Corporation — will have significantly enhanced positions in upstream and downstream operations, a global chemicals business, a growth platform in power generation, and industry-leading skills in technology innovation. Annual synergy savings of at least $1.2 billion are expected within six to nine months of the merger. Though not yet fully quantified, significant costs will also be incurred after the merger for integration-related expenses, including the elimination of duplicate facilities, operational realignment and severance payments for workforce reductions.

The merger is conditioned, among other things, on the approval by the shareholders of both companies, pooling of interests accounting treatment for the merger and approvals of government agencies, such as the U.S. Federal Trade Commission (FTC). Texaco and Chevron anticipate that the FTC will require certain divestitures in the U.S. downstream in order to address market concentration issues, and the companies intend to cooperate with the FTC in this process. In that regard, Texaco is in discussions with our partners in the U.S. downstream.

DESCRIPTION OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements consist of the accounts of Texaco Inc. and subsidiary companies in which we hold direct or indirect voting interest of more than 50%. Intercompany accounts and transactions are eliminated.

The U.S. dollar is the functional currency of all our operations and substantially all of the operations of affiliates accounted for on the equity method. For these operations, translation effects and all gains and losses from transactions not denominated in the functional currency are included in income currently, except for certain hedging transactions. The cumulative translation effects for the equity affiliates using functional currencies other than the U.S. dollar are included in the currency translation adjustment in stockholders' equity.

USE OF ESTIMATES

In preparing Texaco's consolidated financial statements in accordance with generally accepted accounting principles, management is required to use estimates and judgment. While we have considered all available information, actual amounts could differ from those reported as assets and liabilities and related revenues, costs and expenses and the disclosed amounts of contingencies.

REVENUES

We recognize revenues for crude oil, natural gas and refined product sales at the point of passage of title specified in the contract. We record revenues on forward sales where cash has been received to deferred income until title passes.

CASH EQUIVALENTS

We generally classify highly liquid investments with a maturity of three months or less when purchased as cash equivalents.

INVENTORIES

We value inventories at the lower of cost or market, after initially recording at cost. For virtually all inventories of crude oil, petroleum products and petrochemicals, cost is determined on the last-in, first-out (LIFO) method. For other merchandise inventories, cost is generally on the first-in, first-out (FIFO) method. For materials and supplies, cost is at average cost.

INVESTMENTS AND ADVANCES

We use the equity method of accounting for investments in certain affiliates owned 50% or less, including corporate joint ventures, limited liability companies and partnerships. Under this method, we record equity in the pre-tax income or losses of limited liability companies and partnerships, and equity in the net income or losses of corporate joint-venture companies currently in Texaco's revenues, rather than when realized through dividends or distributions.

We record the net income of affiliates accounted for at cost in net income when realized through dividends.

We account for investments in debt securities and in equity securities with readily determinable fair values at fair value if classified as available-for-sale.

PROPERTIES, PLANT AND EQUIPMENT AND DEPRECIATION, DEPLETION AND AMORTIZATION

We follow the "successful efforts" method of accounting for our oil and gas exploration and producing operations.

We capitalize as incurred the lease acquisition costs of properties held for oil, gas and mineral production. We expense as incurred exploratory costs other than wells. We initially capitalize exploratory wells, including stratigraphic test wells, pending further evaluation of whether economically recoverable proved reserves have been found. If such reserves are not found, we charge the well costs to exploratory expenses. For locations not requiring major capital expenditures, we record the charge within one year of well completion. We capitalize intangible drilling costs of productive wells and of development dry holes, and tangible equipment costs. Also capitalized are costs of injected carbon dioxide related to development of oil and gas reserves.

We base our evaluation of impairment for properties, plant and equipment intended to be held on comparison of carrying value against undiscounted future net pre-tax cash flows, generally based on proved developed reserves. If an impairment is identified, we adjust the asset's carrying amount to fair value. We generally account for assets to be disposed of at the lower of net book value or fair value less cost to sell.

We amortize unproved oil and gas properties, when individually significant, by property using a valuation assessment. We generally amortize other unproved oil and gas properties on an aggregate basis over the average holding period for the portion expected to be nonproductive. We amortize productive properties and other tangible and intangible costs of producing activities principally by field. Amortization is based on the unit-of-production basis by applying the ratio of produced oil and gas to estimated recoverable proved oil and gas reserves. We include estimated future restoration and abandonment costs in determining amortization and depreciation rates of productive properties.

We apply depreciation of facilities other than producing properties generally on the group plan, using the straight-line method, with composite rates reflecting the estimated useful life and cost of each class of property. We depreciate facilities not on the group plan individually by estimated useful life using the straight-line method. We exclude estimated salvage value from amounts subject to depreciation. We amortize capitalized non-mineral leases over the estimated useful life of the asset or the lease term, as appropriate, using the straight-line method.

We record periodic maintenance and repairs at manufacturing facilities on the accrual basis. We charge to expense normal maintenance and repairs of all other properties, plant and equipment as incurred. We capitalize renewals, betterments and major repairs that materially extend the useful life of properties and record a retirement of the assets replaced, if any.

When capital assets representing complete units of property are disposed of, we credit or charge to income the difference between the disposal proceeds and net book value.

ENVIRONMENTAL EXPENDITURES

When remediation of a property is probable and the related costs can be reasonably estimated, we accrue the expenses of environmental remediation costs and record them as liabilities. Recoveries or reimbursements are recorded as an asset when receipt is assured. We expense or capitalize other environmental expenditures, principally maintenance or preventive in nature, as appropriate.

DEFERRED INCOME TAXES

We determine deferred income taxes utilizing a liability approach. The income statement effect is derived from changes in deferred income taxes on the balance sheet. This approach gives consideration to the future tax consequences associated with differences between financial accounting and tax bases of assets and liabilities. These differences relate to items such as depreciable and depletable properties, exploratory and intangible drilling costs, non-productive leases, merchandise inventories and certain liabilities. This approach gives immediate effect to changes in income tax laws upon enactment.

We reduce deferred income tax assets by a valuation allowance when it is more likely than not (more than 50%) that a portion will not be realized. Deferred income tax assets are assessed individually by type for this purpose. This process requires the use of estimates and judgment, as many deferred income tax assets have a long potential realization period.

We do not make provision for possible income taxes payable upon distribution of accumulated earnings of foreign subsidiary companies and affiliated corporate joint-venture companies when such earnings are deemed to be permanently reinvested.

ACCOUNTING FOR CONTINGENCIES

Certain conditions may exist as of the date financial statements are issued, which may result in a loss to the company, but which will only be resolved when one or more future events occur or fail to occur. Such contingent liabilities are assessed by the company's management and legal counsel. The assessment of loss contingencies necessarily involves an exercise of judgment and is a matter of opinion. In assessing loss contingencies related to legal proceedings that are pending against the company or unasserted claims that may result in such proceedings, the company's legal counsel evaluates the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material liability had been incurred and the amount of the loss can be estimated, then the estimated liability would be accrued in the company's financial statements. If the assessment indicates that a potentially material liability is not probable, but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss if determinable and material, would be disclosed.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the nature of the guarantee would be disclosed. However, in some instances in which disclosure is not otherwise required, the company may disclose contingent liabilities of an unusual nature which, in the judgment of management and its legal counsel, may be of interest to stockholders or others.

CONSOLIDATED STATEMENT OF CASH FLOWS

We present cash flows from operating activities using the indirect method and reflect our capital expenditures as investing activities.

CONSOLIDATED STATEMENT OF INCOME

(Millions of dollars) For the years ended December 31	**2000**	1999	1998
Revenues			
Sales and services (includes transactions with significant affiliates of $7,811 million in 2000, $4,839 million in 1999 and $4,169 million in 1998)	**$ 50,100**	$ 34,975	$ 30,910
Equity in income of affiliates, interest, asset sales and other	**1,030**	716	797
Total revenues	**51,130**	35,691	31,707
Deductions			
Purchases and other costs (includes transactions with significant affiliates of $3,266 million in 2000, $1,691 million in 1999 and $1,669 million in 1998)	**39,576**	27,442	24,179
Operating expenses	**2,808**	2,319	2,508
Selling, general and administrative expenses	**1,291**	1,186	1,224
Exploratory expenses	**358**	501	461
Depreciation, depletion and amortization	**1,917**	1,543	1,675
Interest expense	**458**	504	480
Taxes other than income taxes	**379**	334	423
Minority interest	**125**	83	56
	46,912	33,912	31,006
Income before income taxes and cumulative effect of accounting change	**4,218**	1,779	701
Provision for income taxes	**1,676**	602	98
Income before cumulative effect of accounting change	**2,542**	1,177	603
Cumulative effect of accounting change	**—**	—	(25)
Net income	**$ 2,542**	$ 1,177	$ 578
Net Income Per Common Share *(dollars)*			
Basic:			
Income before cumulative effect of accounting change	**$ 4.66**	$ 2.14	$ 1.04
Cumulative effect of accounting change	**—**	—	(.05)
Net income	**$ 4.66**	$ 2.14	$ .99
Diluted:			
Income before cumulative effect of accounting change	**$ 4.65**	$ 2.14	$ 1.04
Cumulative effect of accounting change	**—**	—	(.05)
Net income	**$ 4.65**	$ 2.14	$ .99
Average Number of Common Shares Outstanding (for computation of earnings per share) *(thousands)*			
Basic	**542,322**	535,369	528,416
Diluted	**543,952**	537,860	528,965

See accompanying notes to consolidated financial statements.

CONSOLIDATED BALANCE SHEET

(Millions of dollars) As of December 31	**2000**	1999
Assets		
Current Assets		
Cash and cash equivalents	**$ 207**	$ 419
Short-term investments – at fair value	**46**	29
Accounts and notes receivable (includes receivables from significant affiliates of $667 million in 2000 and $585 million in 1999), less allowance for doubtful accounts of $27 million in 2000 and 1999	**5,583**	4,060
Inventories	**1,023**	1,182
Deferred income taxes and other current assets	**194**	273
Total current assets	**7,053**	5,963
Investments and Advances	**6,889**	6,426
Net Properties, Plant and Equipment	**15,681**	15,560
Deferred Charges	**1,244**	1,023
Total	**$ 30,867**	$ 28,972
Liabilities and Stockholders' Equity		
Current Liabilities		
Notes payable, commercial paper and current portion of long-term debt	**$ 376**	$ 1,041
Accounts payable and accrued liabilities (includes payables to significant affiliates of $146 million in 2000 and $61 million in 1999)		
Trade liabilities	**3,314**	2,585
Accrued liabilities	**1,347**	1,203
Estimated income and other taxes	**947**	839
Total current liabilities	**5,984**	5,668
Long-Term Debt and Capital Lease Obligations	**6,815**	6,606
Deferred Income Taxes	**1,547**	1,468
Employee Retirement Benefits	**1,118**	1,184
Deferred Credits and Other Non-Current Liabilities	**1,246**	1,294
Minority Interest in Subsidiary Companies	**713**	710
Total	**17,423**	16,930
Stockholders' Equity		
Market auction preferred shares	**300**	300
Unearned employee compensation and benefit plan trust	**(310)**	(306)
Common stock – shares issued: 567,576,504 in 2000 and 1999	**1,774**	1,774
Paid-in capital in excess of par value	**1,301**	1,287
Retained earnings	**11,297**	9,748
Other comprehensive income	**(130)**	(119)
	14,232	12,684
Less – Common stock held in treasury, at cost	**788**	642
Total stockholders' equity	**13,444**	12,042
Total	**$ 30,867**	$ 28,972

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

(Shares in thousands; amounts in millions of dollars)	**Shares**	**Amount**	Shares	Amount	Shares	Amount
		2000		1999		1998
Preferred Stock						
par value $1; shares authorized – 30,000,000						
Market Auction Preferred Shares (Series G, H, I and J) – liquidation preference of $250,000 per share						
Beginning and end of year	**1**	**$ 300**	1	$ 300	1	$ 300
Series B ESOP Convertible Preferred Stock						
Beginning of year	**—**	**—**	649	389	693	416
Redemptions	**—**	**—**	(587)	(352)	—	—
Retirements	**—**	**—**	(62)	(37)	(44)	(27)
End of year	**—**	**—**	—	—	649	389
Series F ESOP Convertible Preferred Stock						
Beginning of year	**—**	**—**	53	39	56	41
Redemptions	**—**	**—**	(53)	(39)	—	—
Retirements	**—**	**—**	—	—	(3)	(2)
End of year	**—**	**—**	—	—	53	39
Unearned Employee Compensation						
(related to ESOP and restricted stock awards)						
Beginning of year		**(66)**		(94)		(149)
Awards		**(30)**		(18)		(36)
Amortization and other		**26**		46		91
End of year		**(70)**		(66)		(94)
Benefit Plan Trust						
(common stock)						
Beginning and end of year	**9,200**	**(240)**	9,200	(240)	9,200	(240)
Common Stock						
par value $3.125; shares authorized – 850,000,000						
Beginning of year	**567,577**	**1,774**	567,606	1,774	567,606	1,774
Monterey acquisition adjustment	**—**	**—**	(29)	—	—	—
End of year	**567,577**	**1,774**	567,577	1,774	567,606	1,774
Common Stock Held in Treasury, at Cost						
Beginning of year	**14,469**	**(642)**	32,976	(1,435)	25,467	(956)
Redemption of Series B and Series F ESOP Convertible Preferred Stock	**—**	**—**	(16,180)	699	—	—
Purchases of common stock	**3,331**	**(169)**	—	—	9,572	(551)
Other – mainly employee benefit plans	**(386)**	**23**	(2,327)	94	(2,063)	72
End of year	**17,414**	**$ (788)**	14,469	$ (642)	32,976	$ (1,435)

See accompanying notes to consolidated financial statements.

(Continued on next page.)

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

(Millions of dollars)	**2000**	1999	1998
Paid-in Capital in Excess of Par Value			
Beginning of year	**$ 1,287**	$ 1,640	$ 1,688
Redemption of Series B and Series F ESOP Convertible Preferred Stock	**—**	(308)	—
Monterey acquisition adjustment	**—**	(2)	—
Treasury stock transactions relating to investor services plan and employee compensation plans	**14**	(43)	(48)
End of year	**1,301**	1,287	1,640
Retained Earnings			
Balance at beginning of year	**9,748**	9,561	9,987
Add:			
Net income	**2,542**	1,177	578
Tax benefit associated with dividends on unallocated ESOP Convertible Preferred Stock and Common Stock	**—**	2	3
Deduct: Dividends declared on			
Common stock			
($1.80 per share in 2000, 1999 and 1998)	**976**	964	952
Preferred stock			
Series B ESOP Convertible Preferred Stock	**—**	17	38
Series F ESOP Convertible Preferred Stock	**—**	2	4
Market Auction Preferred Shares (Series G, H, I and J)	**17**	9	13
Balance at end of year	**11,297**	9,748	9,561
Other Comprehensive Income			
Currency translation adjustment			
Beginning of year	**(99)**	(107)	(105)
Change during year	**(7)**	8	(2)
End of year	**(106)**	(99)	(107)
Minimum pension liability adjustment			
Beginning of year	**(23)**	(24)	(16)
Change during year	**(4)**	1	(8)
End of year	**(27)**	(23)	(24)
Unrealized net gain on investments			
Beginning of year	**3**	30	26
Change during year	**—**	(27)	4
End of year	**3**	3	30
Total other comprehensive income	**(130)**	(119)	(101)
Stockholders' Equity			
End of year (including preceding page)	**$ 13,444**	$ 12,042	$ 11,833

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(Millions of dollars) For the years ended December 31	**2000**	1999	1998
Net Income	**$ 2,542**	$ 1,177	$ 578
Other Comprehensive Income:			
Currency translation adjustment			
Reclassification to net income of realized loss on sale of affiliate	**—**	17	—
Other unrealized net change during period	**(7)**	(9)	(2)
Total	**(7)**	8	(2)
Minimum pension liability adjustment			
Before income taxes	**(5)**	1	(16)
Income taxes	**1**	—	8
Total	**(4)**	1	(8)
Unrealized net gain on investments			
Net gain (loss) arising during period			
Before income taxes	**1**	12	35
Income taxes	**—**	(2)	(11)
Reclassification to net income of net realized (gain) or loss			
Before income taxes	**(1)**	(48)	(31)
Income taxes	**—**	11	11
Total	**—**	(27)	4
Total other comprehensive income	**(11)**	(18)	(6)
Total comprehensive income	**$ 2,531**	$ 1,159	$ 572

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

(Millions of dollars) For the years ended December 31	**2000**	1999	1998
Operating Activities			
Net income	**$ 2,542**	$ 1,177	$ 578
Reconciliation to net cash provided by (used in) operating activities			
Cumulative effect of accounting change	**—**	—	25
Depreciation, depletion and amortization	**1,917**	1,543	1,675
Deferred income taxes	**134**	(140)	(152)
Minority interest in net income	**125**	83	56
Dividends from affiliates, greater than equity in income	**77**	233	224
Gains on asset sales	**(141)**	(87)	(109)
Changes in operating working capital			
Accounts and notes receivable	**(1,549)**	(637)	125
Inventories	**131**	(28)	(51)
Accounts payable and accrued liabilities	**621**	382	16
Other – mainly estimated income and other taxes	**50**	130	(205)
Other – net	**(43)**	29	(89)
Net cash provided by operating activities	**3,864**	2,685	2,093
Investing Activities			
Capital expenditures	**(2,974)**	(2,473)	(2,650)
Proceeds from asset sales	**684**	321	282
Sales (purchases) of leasehold interests	**—**	(23)	25
Purchases of investment instruments	**(340)**	(432)	(947)
Sales/maturities of investment instruments	**279**	778	1,118
Collection of note/formation payments from U.S. affiliate	**—**	101	612
Net cash used in investing activities	**(2,351)**	(1,728)	(1,560)
Financing Activities			
Borrowings having original terms in excess of three months			
Proceeds	**808**	2,353	1,300
Repayments	**(2,167)**	(1,080)	(741)
Net increase (decrease) in other borrowings	**915**	(983)	493
Purchases of common stock	**(169)**	—	(579)
Dividends paid to the company's stockholders			
Common	**(976)**	(964)	(952)
Preferred	**(15)**	(28)	(53)
Dividends paid to minority stockholders	**(125)**	(55)	(52)
Net cash used in financing activities	**(1,729)**	(757)	(584)
Cash and Cash Equivalents			
Effect of exchange rate changes	**4**	(30)	(11)
Increase (decrease) during year	**(212)**	170	(62)
Beginning of year	**419**	249	311
End of year	**$ 207**	$ 419	$ 249

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 SEGMENT INFORMATION

Operating segments are based on differences in the nature of their operations, geographic location and internal management reporting. The composition of segments and measure of segment profit are consistent with that used by our Executive Council in making strategic decisions. The Executive Council is headed by the Chairman and Chief Executive Officer and includes, among others, the Senior Vice Presidents having oversight responsibility for our business units.

Operating Segments 2000

	Sales and Services								
(Millions of dollars)	Outside	Inter-segment	Total	After-Tax Profit (Loss)	Income Tax Expense (Benefit)	DD&A Expense	Other Non-Cash Items	Capital Expen-ditures	Assets at Year-End
Exploration and production									
United States	**$ 3,693**	**$ 2,127**	**$ 5,820**	**$ 1,518**	**$ 806**	**$ 1,148**	**$ 203**	**$ 975**	**$ 8,442**
International	**3,578**	**1,504**	**5,082**	**1,077**	**1,149**	**406**	**161**	**1,367**	**6,343**
Refining, marketing and distribution									
United States	**6,027**	**21**	**6,048**	**158**	**119**	**2**	**149**	**8**	**3,495**
International	**29,099**	**393**	**29,492**	**143**	**80**	**328**	**182**	**294**	**8,865**
Global gas, power and energy technology	**7,693**	**223**	**7,916**	**50**	**28**	**11**	**10**	**269**	**2,580**
Segment totals	**$ 50,090**	**$ 4,268**	**54,358**	**2,946**	**2,182**	**1,895**	**705**	**2,913**	**29,725**
Other business units			**30**	**(11)**	**(5)**	**—**	**(6)**	**—**	**341**
Corporate/Non-operating			**6**	**(393)**	**(501)**	**22**	**228**	**61**	**1,185**
Intersegment eliminations			**(4,294)**	**—**	**—**	**—**	**—**	**—**	**(384)**
Consolidated			**$ 50,100**	**$ 2,542**	**$ 1,676**	**$ 1,917**	**$ 927**	**$ 2,974**	**$ 30,867**

Operating Segments 1999

	Sales and Services								
(Millions of dollars)	Outside	Inter-segment	Total	After-Tax Profit (Loss)	Income Tax Expense (Benefit)	DD&A Expense	Other Non-Cash Items	Capital Expen-ditures	Assets at Year-End
Exploration and production									
United States	$ 2,166	$ 1,547	$ 3,713	$ 652	$ 299	$ 758	$ 167	$ 660	$ 8,696
International	2,684	924	3,608	360	545	451	30	1,267	5,333
Refining, marketing and distribution									
United States	3,579	18	3,597	208	73	3	78	3	3,714
International	22,114	75	22,189	370	101	220	132	361	8,542
Global gas, power and energy technology	4,422	117	4,539	(14)	(8)	65	10	161	1,297
Segment totals	$ 34,965	$ 2,681	37,646	1,576	1,010	1,497	417	2,452	27,582
Other business units			32	(3)	(2)	1	—	—	365
Corporate/Non-operating			6	(396)	(406)	45	(1)	21	1,430
Intersegment eliminations			(2,709)	—	—	—	—	—	(405)
Consolidated			$ 34,975	$ 1,177	$ 602	$ 1,543	$ 416	$ 2,473	$ 28,972

Operating Segments 1998

(Millions of dollars)	Sales and Services Outside	Inter-segment	Total	After-Tax Profit (Loss)	Income Tax Expense (Benefit)	DD&A Expense	Other Non-Cash Items	Capital Expen-ditures	Assets at Year-End
Exploration and production									
United States	$ 1,712	$ 1,659	$ 3,371	$ 301	$ 34	$ 892	$ 1	$ 1,200	$ 8,699
International	2,020	695	2,715	129	132	513	18	901	4,345
Refining, marketing and distribution									
United States	2,612	29	2,641	221	88	29	230	1	4,066
International	19,805	106	19,911	332	130	204	135	396	8,214
Global gas, power and energy technology	4,748	76	4,824	(16)	4	15	45	122	1,119
Segment totals	$ 30,897	$ 2,565	33,462	967	388	1,653	429	2,620	26,443
Other business units			50	(2)	—	1	3	—	381
Corporate/Non-operating			5	(362)	(290)	21	(67)	30	1,945
Intersegment eliminations			(2,607)	—	—	—	—	—	(199)
Consolidated, before cumulative effect of accounting change			$ 30,910	$ 603	$ 98	$ 1,675	$ 365	$ 2,650	$ 28,570

Our exploration and production segments explore for, find, develop and produce crude oil and natural gas. The United States segment in 1998 included minor operations in Canada. Our refining, marketing and distribution segments process crude oil and other feedstocks into refined products and purchase, sell and transport crude oil and refined petroleum products. The global gas, power and energy technology segment includes the U.S. natural gas operations which purchases natural gas and natural gas products from our exploration and production operations and third parties for resale. It also operates natural gas processing plants and pipelines in the United States. Also included in this segment are our power generation, gasification, hydrocarbons-to-liquids, battery and fuel cell technology operations. This segment sold its U.K. wholesale gas business in 1998 and its U.K. retail gas marketing business in 1999. Other business units include our insurance operations and investments in undeveloped mineral properties. None of these units is individually significant in terms of revenue, income or assets.

You are encouraged to read Note 5 which includes information about our affiliates and the formation of the Equilon and Motiva alliances in 1998.

Corporate and non-operating includes the assets, income and expenses relating to cash management and financing activities, our corporate center and other items not directly attributable to the operating segments.

We apply the same accounting policies to each of the segments as we do in preparing the consolidated financial statements. Intersegment sales and services are generally representative of market prices or arms-length negotiated transactions. Intersegment receivables are representative of normal trade balances. Other non-cash items principally include deferred income taxes, the difference between cash distributions and equity in income of affiliates, and non-cash charges and credits associated with asset sales. Capital expenditures are presented on a cash basis, excluding exploratory expenses.

The countries in which we have significant sales and services and long-lived assets are listed below. Sales and services are based on the origin of the sale. Long-lived assets include properties, plant and equipment and investments in foreign operations where the host governments own the physical assets under terms of the operating agreements.

	Sales and Services			Long-lived assets at December 31		
(Millions of dollars)	**2000**	1999	1998	**2000**	1999	1998
United States	**$ 17,074**	$ 9,733	$ 8,184	**$ 8,018**	$ 8,630	$ 8,757
International – Total	**$ 33,026**	$ 25,242	$ 22,726	**$ 7,879**	$ 7,109	$ 6,250
Significant countries included above:						
Brazil	**3,023**	2,404	3,175	**336**	326	301
Netherlands	**2,570**	1,955	1,636	**232**	246	257
Philippines	**—**	—	—	**1,132**	554	—
United Kingdom	**11,472**	9,211	7,529	**2,460**	2,275	2,257

NOTE 2 ADOPTION OF NEW ACCOUNTING STANDARDS

Effective January 1, 1998, Caltex, our affiliate, adopted Statement of Position 98-5, "Reporting on the Costs of Start-Up Activities," issued by the American Institute of Certified Public Accountants. This Statement requires that the costs of start-up activities and organization costs, as defined, be expensed as incurred. The cumulative effect of adoption on Texaco's net income for 1998 was a net loss of $25 million. This Statement was adopted by Texaco and our other affiliates effective January 1, 1999. The effect was not significant.

In June 1998, the Financial Accounting Standards Board (FASB) issued SFAS 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS 133 establishes new accounting rules and disclosure requirements for most derivative instruments and hedge transactions. In June 1999, the FASB issued SFAS 137, which deferred the effective date of SFAS 133. This was followed in June 2000 by the issuance of SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities," which amended SFAS 133.

We are adopting these standards effective January 1, 2001. The cumulative effects of adoption at that date on net income and other comprehensive income are not material to net income and stockholders' equity.

NOTE 3 INCOME PER COMMON SHARE

Basic net income per common share is net income less preferred stock dividend requirements divided by the average number of common shares outstanding. Diluted net income per common share assumes issuance of the net incremental shares from stock options and full conversion of all dilutive convertible securities at the later of the beginning of the year or date of issuance. Common shares held by the benefit plan trust are not considered outstanding for purposes of net income per common share.

(Millions, except per share amounts)		**2000**			1999			1998	
For the years ended December 31	**Income**	**Shares**	**Per Share**	Income	Shares	Per Share	Income	Shares	Per Share
Basic net income:									
Income before cumulative effect of accounting change	**$ 2,542**			$ 1,177			$ 603		
Less: Preferred stock dividends	**(15)**			(29)			(54)		
Income before cumulative effect of accounting change, for basic income per share	**$ 2,527**	**542.3**	**$ 4.66**	$ 1,148	535.4	$ 2.14	$ 549	528.4	$ 1.04
Effect of dilutive securities:									
Stock options and restricted stock	**3**	**1.7**		3	2.5		—	.4	
Convertible debentures	**—**	**—**		—	—		1	.2	
Income before cumulative effect of accounting change, for diluted income per share	**$ 2,530**	**544.0**	**$ 4.65**	$ 1,151	537.9	$ 2.14	$ 550	529.0	$ 1.04

NOTE 4 INVENTORIES

(Millions of dollars) *As of December 31*	2000	1999
Crude oil	**$ 127**	$ 141
Petroleum products and other	**732**	857
Materials and supplies	**164**	184
Total	**$ 1,023**	$ 1,182

At December 31, 2000 and 1999, the excess of estimated market value over the carrying value of inventories was $210 million and $194 million.

NOTE 5 INVESTMENTS AND ADVANCES

We account for our investments in affiliates, including corporate joint ventures and partnerships owned 50% or less, on the equity method. Our total investments and advances are summarized as follows:

(Millions of dollars) *As of December 31*	2000	1999
Affiliates accounted for on the equity method		
Exploration and production		
United States	**$ 269**	$ 243
International		
CPI	**465**	454
Other	**145**	14
	879	711
Refining, marketing and distribution		
United States		
Equilon	**1,724**	1,953
Motiva	**743**	686
Other	**5**	8
International		
Caltex	**1,682**	1,685
Other	**238**	234
	4,392	4,566
Global gas, power and energy technology	**630**	286
Total	**5,901**	5,563
Miscellaneous investments, long-term receivables, etc., accounted for at:		
Fair value	**122**	138
Cost, less reserve	**866**	725
Total	**$ 6,889**	$ 6,426

Our equity in the net income of affiliates is adjusted to reflect income taxes for limited liability companies and partnerships whose income is directly taxable to us:

(Millions of dollars) *For the years ended December 31*	2000	1999	1998
Equity in net income (loss)			
Exploration and production			
United States	**$ 83**	$ 53	$ 37
International			
CPI	**255**	139	107
Other	**1**	—	(12)
	339	192	132
Refining, marketing and distribution			
United States			
Equilon	**98**	142	199
Motiva	**100**	(3)	22
Other	**27**	—	(3)
International			
Caltex	**5**	11	(36)
Other	**8**	27	15
	238	177	197
Global gas, power and energy technology	**36**	6	(11)
Total	**$ 613**	$ 375	$ 318
Dividends received	**$ 863**	$ 716	$ 709

The undistributed earnings of these affiliates included in our retained earnings were $2,536 million, $2,613 million and $2,846 million as of December 31, 2000, 1999 and 1998.

Caltex Group

We have investments in the Caltex Group of Companies, owned 50% by Texaco and 50% by Chevron Corporation. The Caltex Group consists of P.T. Caltex Pacific Indonesia (CPI), American Overseas Petroleum Limited and subsidiary and Caltex Corporation and subsidiaries (Caltex). This group of companies is engaged in the exploration for and production, transportation, refining and marketing of crude oil and products in Africa, Asia, Australia, the Middle East and New Zealand.

Results for the Caltex Group in 1998 include an after-tax charge of $50 million (Texaco's share $25 million) for the cumulative effect of an accounting change. See Note 2 for additional information.

Equilon Enterprises LLC

Effective January 1, 1998, Texaco and Shell Oil Company formed Equilon Enterprises LLC (Equilon), a Delaware limited liability company. Equilon is a joint venture that combined major elements of the companies' western and midwestern U.S. refining and marketing businesses and their nationwide trading, transportation and lubricants businesses. We own 44% and Shell Oil Company owns 56% of Equilon.

The carrying amounts at January 1, 1998, of the principal assets and liabilities of the businesses we contributed to Equilon were $.2 billion of net working capital assets, $2.8 billion of net properties, plant and equipment and $.2 billion of debt. These amounts were reclassified to investment in affiliates accounted for by the equity method.

In April 1998, we received $463 million from Equilon, representing reimbursement of certain capital expenditures incurred prior to the formation of the joint venture. In July 1998, we received $149 million from Equilon for certain specifically identified assets transferred for value to Equilon. In February 1999, we received $101 million from Equilon for the payment of notes receivable.

Motiva Enterprises LLC

Effective July 1, 1998, Texaco, Shell and Saudi Aramco formed Motiva Enterprises LLC (Motiva), a Delaware limited liability company. Motiva is a joint venture that combined Texaco's and Saudi Aramco's interests and major elements of Shell's East and Gulf Coast U.S. refining and marketing businesses. Texaco's and Saudi Aramco's interests in these businesses were previously conducted by Star Enterprise (Star), a joint-venture partnership owned 50% by Texaco and 50% by Saudi Refining, Inc., a corporate affiliate of Saudi Aramco.

From July 1, 1998, through December 31, 1999, Texaco and Saudi Refining, Inc. each owned 32.5% and Shell owned 35% of Motiva. Under the terms of the Limited Liability Agreement for Motiva, the ownership in Motiva is subject to annual adjustment through year-end 2005, based on the performance of the assets contributed to Motiva. Accordingly, the initial ownership in Motiva was adjusted effective as of January 1, 2000, so that for the year 2000, Texaco and Saudi Refining, Inc. each owned just under 31% and Shell owned just under 39% of Motiva. The Agreement provides that a final ownership percentage will be calculated at the end of 2005.

The investment in Motiva at date of formation approximated the previous investment in Star. The Motiva investment and previous Star investment are recorded as investment in affiliates accounted for on the equity method.

The following table provides summarized financial information on a 100% basis for the Caltex Group, Equilon, Motiva, Star and all other affiliates that we account for on the equity method, as well as Texaco's total share of the information. The net income of all limited liability companies and partnerships is net of estimated income taxes. The actual income tax liability is reflected in the accounts of the respective members or partners and is not shown in the following table.

(Millions of dollars)	**Equilon**	**Motiva**	**Caltex Group**	**Other Affiliates**	**Total Texaco's Share**
2000					
Gross revenues	**$ 50,010**	**$ 19,446**	**$ 20,239**	**$ 4,163**	**$ 39,913**
Income before income taxes	**$ 228**	**$ 461**	**$ 1,088**	**$ 408**	**$ 993**
Net income	**$ 148**	**$ 300**	**$ 519**	**$ 283**	**$ 613**
As of December 31:					
Current assets	**$ 3,134**	**$ 1,381**	**$ 2,544**	**$ 1,652**	**$ 3,782**
Non-current assets	**6,830**	**5,110**	**7,678**	**4,318**	**9,656**
Current liabilities	**(4,587)**	**(1,150)**	**(3,385)**	**(1,280)**	**(4,650)**
Non-current liabilities	**(897)**	**(2,017)**	**(2,543)**	**(1,816)**	**(2,887)**
Net equity	**$ 4,480**	**$ 3,324**	**$ 4,294**	**$ 2,874**	**$ 5,901**

(Millions of dollars)	Equilon	Motiva	Caltex Group	Other Affiliates	Total Texaco's Share
1999					
Gross revenues	$ 29,398	$ 12,196	$ 14,942	$ 2,895	$ 25,663
Income (loss) before income taxes	$ 347	$ (69)	$ 780	$ 348	$ 679
Net income (loss)	$ 226	$ (45)	$ 390	$ 232	$ 375
As of December 31:					
Current assets	$ 3,426	$ 1,271	$ 2,705	$ 801	$ 3,452
Non-current assets	7,208	5,307	7,632	2,230	9,335
Current liabilities	(4,853)	(1,278)	(3,395)	(736)	(4,572)
Non-current liabilities	(735)	(2,095)	(2,667)	(792)	(2,652)
Net equity	$ 5,046	$ 3,205	$ 4,275	$ 1,503	$ 5,563

(Millions of dollars)	Equilon	Motiva	Star	Caltex Group	Other Affiliates	Total Texaco's Share
1998						
Gross revenues	$ 22,246	$ 5,371	$ 3,190	$ 11,522	$ 2,541	$ 20,030
Income (loss) before income taxes and cumulative effect of accounting change	$ 502	$ 78	$ (128)	$ 519	$ 170	$ 662
Net income (loss)	$ 326	$ 51	$ (83)	$ 143	$ 84	$ 318
As of December 31:						
Current assets	$ 2,640	$ 1,481		$ 1,974	$ 687	$ 2,769
Non-current assets	7,752	5,257		7,684	2,021	9,313
Current liabilities	(4,044)	(1,243)		(2,839)	(727)	(3,924)
Non-current liabilities	(382)	(1,667)		(2,421)	(672)	(2,142)
Net equity	$ 5,966	$ 3,828		$ 4,398	$ 1,309	$ 6,016

NOTE 6 PROPERTIES, PLANT AND EQUIPMENT

	Gross		Net	
(Millions of dollars) As of December 31	**2000**	1999	**2000**	1999
Exploration and production				
United States	**$ 19,301**	$ 21,565	**$ 7,258**	$ 7,822
International	**7,418**	8,835	**4,612**	3,804
Total	**26,719**	30,400	**11,870**	11,626
Refining, marketing and distribution				
United States	**37**	33	**23**	22
International	**4,684**	4,575	**3,031**	3,107
Total	**4,721**	4,608	**3,054**	3,129
Global gas, power and energy technology	**615**	748	**280**	317
Other	**766**	771	**477**	488
Total	**$ 32,821**	$ 36,527	**$ 15,681**	$ 15,560
Capital lease amounts included above	**$ 212**	$ 152	**$ 57**	$ 3

Accumulated depreciation, depletion and amortization totaled $17,140 million and $20,967 million at December 31, 2000 and 1999. Interest capitalized as part of properties, plant and equipment was $76 million in 2000, $28 million in 1999 and $21 million in 1998.

In 2000, 1999 and 1998, we recorded pre-tax charges of $337 million, $87 million and $150 million for the write-downs of impaired assets. These charges were recorded to depreciation, depletion and amortization expense.

2000

In the U.S. exploration and production operating segment, pre-tax asset write-downs for impaired properties mostly in the Gulf of Mexico and Gulf Coast were $203 million. These impairments were caused by downward revisions of the estimated volume of the fields' proved reserves and changes in our outlook of future production. We determined in the fourth quarter of 2000 that the carrying values of these properties exceeded future undiscounted cash flows. Fair value was determined by discounting expected future cash flows.

In the international exploration and production operating segment, the pre-tax asset write-down for the impairment of a project in the U.K. North Sea was $29 million. The impairment was caused by a determination made in the fourth quarter of 2000 that we do not plan to develop this property.

In the international downstream operating segment, the pre-tax asset write-down for the impairment of the Panama refinery was $105 million. We determined that the carrying value of the refinery exceeded undiscounted future cash flows. The impairment of the entire carrying value of the refinery was caused by a final determination in the fourth quarter of 2000 that the unfavorable operating environment and downward pressure on profit margins would not improve in the foreseeable future.

1999

In our global gas, power and energy technology operating segment, pre-tax asset write-downs from the impairment of certain gas plants in Louisiana were $49 million. We determined in the fourth quarter that, as a result of declining gas volumes available for processing, the carrying value of these plants exceeded future undiscounted cash flows. Fair value was determined by discounting expected future cash flows.

Pre-tax asset write-downs of $28 million included in corporate resulted from our joint plan with state and local agencies to convert for third-party industrial use idle facilities, formerly used in research activities. The facilities and equipment were written down to their appraised values. An additional $10 million was recorded to bring certain marketing assets of our subsidiary in Poland to be disposed of to their appraised value.

1998

In the U.S. exploration and production operating segment, pre-tax asset write-downs for impaired properties in Louisiana and Canada were $64 million. The Louisiana property represents an unsuccessful enhanced recovery project. We determined in the fourth quarter of 1998 that the carrying value of this property exceeded future undiscounted cash flows. Fair value was determined by discounting expected future cash flows. Canadian properties were impaired following our decision in October 1998 to exit the upstream business in Canada. These properties were written down to their sales price with the sale closing in December 1998.

In the international exploration and production operating segment, the pre-tax asset write-down for the impairment of our investment in the Strathspey field in the U.K. North Sea was $58 million. The Strathspey impairment was caused by a downward revision in the fourth quarter of the estimated volume of the field's proved reserves. Fair value was determined by discounting expected future cash flows.

In the U.S. downstream operating segment, the pre-tax asset write-downs for the impairment of surplus facilities and equipment held for sale and not transferred to the Equilon joint venture was $28 million. Fair value was determined by an independent appraisal.

NOTE 7 FOREIGN CURRENCY

Currency translation effects and currency transactions resulted in pre-tax losses of $88 million in 2000, $47 million in 1999 and $80 million in 1998. After applicable taxes, 2000 included a gain of $37 million and 1999 included a gain of $25 million as compared to a loss of $94 million in 1998.

The after-tax currency gain in 2000 and 1999 related principally to balance sheet translation. After-tax currency impacts for year 1998 were largely due to currency volatility in Asia. In 1998, our Caltex affiliate incurred significant currency-related losses due to the strengthening of the Korean won and Japanese yen against the U.S. dollar.

Results for 1998 through 2000 were also impacted by the effect of currency rate changes on deferred income taxes denominated in British pounds. This results in gains from strengthening of the U.S. dollar and losses from weakening of the U.S. dollar. These effects were gains of $12 million in 2000 and $8 million in 1999 and losses of $5 million in 1998.

Currency translation adjustments shown in the separate stockholders' equity account result from translation items pertaining to certain affiliates of Caltex. For 2000, we recorded unrealized losses of $7 million from these adjustments. In 1999, we recorded unrealized losses of $9 million and in addition, we reversed an existing $17 million deferred loss due to the sale by Caltex of its investment in Koa Oil Company, Limited. As a result, a $17 million loss was recorded in Texaco's net income as part of the loss on this sale. For the year 1998, currency translation losses recorded to stockholders' equity amounted to $2 million.

NOTE 8 TAXES

(Millions of dollars)	**2000**	1999	1998
Federal and other income taxes			
Current			
U.S. Federal	**$ 278**	$ 100	$ (45)
Foreign	**1,265**	678	283
State and local	**(1)**	(36)	12
Total	**1,542**	742	250
Deferred			
U.S.	**87**	(120)	(104)
Foreign	**47**	(20)	(48)
Total	**134**	(140)	(152)
Total income taxes	**1,676**	602	98
Taxes other than income taxes			
Oil and gas production	**117**	64	70
Property	**90**	69	108
Payroll	**81**	91	119
Other	**91**	110	126
Total	**379**	334	423
Import duties and other levies			
U.S.	**25**	34	36
Foreign	**6,928**	6,937	6,843
Total	**6,953**	6,971	6,879
Total direct taxes	**9,008**	7,907	7,400
Taxes collected from consumers	**2,519**	2,097	2,148
Total all taxes	**$ 11,527**	$ 10,004	$ 9,548

The deferred income tax assets and liabilities included in the Consolidated Balance Sheet as of December 31, 2000 and 1999 amounted to $154 million and $198 million, as net current assets and $1,547 million and $1,468 million, as net non-current liabilities.

The table that follows shows deferred income tax assets and liabilities by category:

(Millions of dollars) As of December 31	(Liability) Asset 2000	1999
Depreciation	**$ (831)**	$ (991)
Depletion	**(416)**	(383)
Intangible drilling costs	**(888)**	(881)
Other deferred tax liabilities	**(788)**	(691)
Total	**(2,923)**	(2,946)
Employee benefit plans	**565**	548
Tax loss carryforwards	**405**	599
Tax credit carryforwards	**273**	495
Environmental liabilities	**130**	123
Other deferred tax assets	**984**	711
Total	**2,357**	2,476
Total before valuation allowance	**(566)**	(470)
Valuation allowance	**(827)**	(800)
Total	**$ (1,393)**	$ (1,270)

The preceding table excludes certain potential deferred income tax asset amounts for which possibility of realization is extremely remote.

The valuation allowance relates principally to upstream operations in Denmark. The related deferred income tax assets result from tax loss carryforwards and book versus tax asset basis differences for a hydrocarbon tax. Loss carryforwards from this tax are generally determined by individual field and, in that case, are not usable against other fields' taxable income.

The following schedule reconciles the differences between the U.S. Federal income tax rate and the effective income tax rate excluding the cumulative effect of accounting change in 1998:

	2000	1999	1998
U.S. Federal income tax rate assumed to be applicable	**35.0%**	35.0%	35.0%
Net earnings and dividends attributable to affiliated corporations accounted for on the equity method	**(2.4)**	(3.8)	(7.0)
Aggregate earnings and losses from international operations	**12.9**	14.4	10.4
U.S. tax adjustments	**(3.3)**	(5.0)	(8.7)
Sales of stock of subsidiaries	**(1.7)**	(2.2)	(6.1)
Energy credits	**(1.5)**	(3.8)	(11.7)
Other	**.7**	(.8)	2.1
Effective income tax rate	**39.7%**	33.8%	14.0%

For companies operating in the United States, pre-tax earnings before the cumulative effect of an accounting change aggregated $1,899 million in 2000, $484 million in 1999 and $194 million in 1998. For companies with operations located outside the United States, pre-tax earnings on that basis aggregated $2,319 million in 2000, $1,295 million in 1999 and $507 million in 1998.

Income taxes paid, net of refunds, amounted to $1,374 million, $600 million and $430 million in 2000, 1999 and 1998.

The undistributed earnings of subsidiary companies and of affiliated corporate joint-venture companies accounted for on the equity method, for which deferred U.S. income taxes have not been provided at December 31, 2000, amounted to $1,995 million and $2,206 million. The corresponding amounts at December 31, 1999 were $1,708 million and $2,187 million. Determination of the unrecognized U.S. deferred income taxes on these amounts is not practicable.

For the years 2000, 1999 and 1998, no loss carryforward benefits were recorded for U.S. Federal income taxes. For the years 2000, 1999 and 1998, the tax benefits recorded for loss carryforwards were $89 million, $54 million and $30 million in foreign income taxes.

At December 31, 2000, we had worldwide tax basis loss carryforwards of approximately $1,299 million, including $753 million which do not have an expiration date. The remainder expire at various dates through 2019.

Foreign tax credit carryforwards available for U.S. Federal income tax purposes amounted to approximately $295 million at December 31, 2000, expiring at various dates through 2005. Alternative minimum tax credit carryforwards for U.S. Federal income tax purposes were $258 million at December 31, 2000. For the year 2000, we utilized tax credit carryforwards of $189 million for U.S. Federal income tax purposes.

NOTE 9 SHORT-TERM DEBT, LONG-TERM DEBT, CAPITAL LEASE OBLIGATIONS AND RELATED DERIVATIVES

Notes Payable, Commercial Paper and Current Portion of Long-Term Debt

(Millions of dollars) As of December 31	2000	1999
Notes payable to banks and others with originating terms of one year or less	**$ 362**	$ 1,251
Commercial paper	**1,439**	1,099
Current portion of long-term debt and capital lease obligations		
Indebtedness	**986**	734
Capital lease obligations	**7**	7
	2,794	3,091
Less short-term obligations intended to be refinanced	**2,418**	2,050
Total	**$ 376**	$ 1,041

The weighted average interest rates of commercial paper and notes payable to banks at December 31, 2000 and 1999 were 6.6% and 5.9%.

Long-Term Debt and Capital Lease Obligations

(Millions of dollars) As of December 31	**2000**	1999
Long-Term Debt		
3-1/2% convertible notes due 2004	**$ 203**	$ 203
5.5% note due 2009	**392**	397
5.7% notes due 2008	**201**	201
6% notes due 2005	**299**	299
6-7/8% debentures due 2023	**196**	196
7.09% notes due 2007	**150**	150
7-1/2% debentures due 2043	**198**	198
7-3/4% debentures due 2033	**199**	199
8% debentures due 2032	**148**	148
8-1/4% debentures due 2006	**150**	150
8-3/8% debentures due 2022	**198**	198
8-1/2% notes due 2003	**200**	200
8-5/8% debentures due 2010	**150**	150
8-5/8% debentures due 2031	**199**	199
8-5/8% debentures due 2032	**199**	199
8-7/8% debentures due 2021	**150**	150
9-3/4% debentures due 2020	**250**	250
Medium-term notes, maturing from 2001 to 2043 (7.1%)	**1,081**	757
Pollution Control Revenue Bonds, due 2012 – variable rate (4.3%)	**166**	166
Other long-term debt:		
U.S. dollars (6.6%)	**248**	369
Other currencies (6.4%)	**367**	472
Total	**5,344**	5,251
Capital Lease Obligations (see Note 10)	**46**	46
	5,390	5,297
Less current portion of long-term debt and capital lease obligations	**993**	741
	4,397	4,556
Short-term obligations intended to be refinanced	**2,418**	2,050
Total long-term debt and capital lease obligations	**$ 6,815**	$ 6,606

The percentages shown for variable-rate debt are the interest rates at December 31, 2000. The percentages shown for the categories “Medium-term notes” and “Other long-term debt” are the weighted average interest rates at year-end 2000. Where applicable, principal amounts shown in the preceding schedule include unamortized premium or discount. Texaco Inc. or Texaco Capital Inc., a wholly-owned finance subsidiary of Texaco Inc., has issued all of our publicly traded long-term debt. Texaco Inc. has fully and unconditionally guaranteed all of Texaco Capital Inc.’s outstanding debt. Interest paid, net of amounts capitalized, amounted to $440 million in 2000, $480 million in 1999 and $474 million in 1998.

At December 31, 2000, we had revolving credit facilities with commitments of $2.575 billion with syndicates of major U.S. and international banks. These facilities are available as support for our issuance of commercial paper as well as for working capital and other general corporate purposes. We had no amounts outstanding under these facilities at year-end 2000. We pay commitment fees on these facilities. The banks reserve the right to terminate the credit facilities upon the occurrence of certain specific events, including a change in control. However, the banks have waived these change in control provisions with respect to the proposed Chevron-Texaco merger.

At December 31, 2000, our long-term debt included $2.418 billion of short-term obligations scheduled to mature during 2001, which we have both the intent and the ability to refinance on a long-term basis through the use of our $2.575 billion revolving credit facilities.

Contractual annual maturities of long-term debt, including sinking fund payments and potential repayments resulting from options that debtholders might exercise, for the five years subsequent to December 31, 2000 are as follows (in millions):

2001	2002	2003	2004	2005
$ 986	$ 201	$ 273	$ 25	$ 435

Debt-Related Derivatives

We seek to maintain a balanced capital structure that provides financial flexibility and supports our strategic objectives while achieving a low cost of capital. This is achieved by balancing our liquidity and interest rate exposures. We manage these exposures primarily through long-term and short-term debt on the balance sheet. In managing our exposure to interest rates, we seek to balance the benefit of lower cost floating rate debt, having refinancing risk, with fixed rate debt not having this risk. To achieve this objective, we also use off-balance sheet derivative instruments, primarily non-leveraged interest rate swaps, to manage identifiable exposures on a non-speculative basis.

Summarized below are the carrying amounts and fair values of our debt and debt-related derivatives at December 31, 2000 and 1999. Our use of derivatives during the periods presented was limited to interest rate swaps, where we either paid or received the net effect of a fixed rate versus a floating rate (commercial paper or

LIBOR) index at specified intervals, calculated by reference to an agreed notional principal amount.

(Millions of dollars) As of December 31	**2000**	1999
Notes Payable and Commercial Paper:		
Carrying amount	**$ 1,801**	$ 2,350
Fair value	**1,801**	2,348
Related Derivatives – Payable (Receivable):		
Carrying amount	**$ —**	$ —
Fair value	**—**	(13)
Notional principal amount	**$ —**	$ 300
Weighted average maturity *(years)*	**—**	7.3
Weighted average fixed pay rate	**—**	6.42%
Weighted average floating receive rate	**—**	6.42%
Long-Term Debt, including current maturities:		
Carrying amount	**$ 5,344**	$ 5,251
Fair value	**5,465**	5,225
Related Derivatives – Payable (Receivable):		
Carrying amount	**$ (35)**	$ (19)
Fair value	**(7)**	55
Notional principal amount	**$ 1,275**	$ 1,294
Weighted average maturity *(years)*	**5.3**	5.8
Weighted average fixed receive rate	**6.18%**	5.69%
Weighted average floating pay rate	**6.36%**	6.10%
Unamortized net gain on terminated swaps		
Carrying amount	**$ 17**	$ 4

Excluded from this table is an interest rate and equity swap with a notional principal amount of $200 million entered into in 1997, related to the 3-1/2% notes due 2004. We pay a floating rate and receive a fixed rate and the counterparty assumes all exposure for the potential equity-based cash redemption premium on the notes. The fair value of this swap was not significant at year-end 2000 and 1999.

During 2000, floating rate pay swaps aggregating $549 million notional and fixed rate pay swaps of $300 million notional were terminated or matured. We initiated $530 million notional of new floating rate pay swaps in connection with year 2000 debt issues.

Fair values of debt are based upon quoted market prices, where available and, where not, on interest rates currently available to us for borrowings with similar terms and maturities. We estimate the fair value of swaps as the amount that would be received or paid to terminate the agreements at year end, taking into account current interest rates and the current creditworthiness of the swap counterparties.

The notional amounts of derivative contracts do not represent cash flow and are not subject to credit risk.

Amounts receivable or payable based on the interest rate differentials of derivatives are accrued monthly and are reflected in interest expense as a hedge of interest on outstanding debt. Gains and losses on terminated swaps are deferred and amortized over the life of the associated debt or the original term of the swap, whichever is shorter.

NOTE 10 LEASE COMMITMENTS AND RENTAL EXPENSE

We have leasing arrangements involving service stations, tanker charters, crude oil production and processing equipment and other facilities. We reflect amounts due under capital leases in our balance sheet as obligations, while we reflect our interest in the related assets as properties, plant and equipment. The remaining lease commitments are operating leases, and we record payments on such leases as rental expense.

As of December 31, 2000, we had estimated minimum commitments for payment of rentals (net of non-cancelable sublease rentals) under leases which, at inception, had a non-cancelable term of more than one year, as follows:

(Millions of dollars)	Operating Leases	Capital Leases
2001	$ 130	$ 10
2002	421	10
2003	56	9
2004	51	9
2005	40	8
After 2005	287	11
Total lease commitments	$ 985	$ 57
Less interest		11
Present value of total capital lease obligations		$ 46

Operating lease commitments for 2002 include a $304 million residual value guarantee of leased production facilities if we do not renew the lease.

Rental expense relative to operating leases, including contingent rentals based on factors such as gallons sold, is provided in the table below. Such payments do not include rentals on leases covering oil and gas mineral rights.

(Millions of dollars)	**2000**	1999	1998
Rental expense			
Minimum lease rentals	**$ 229**	$ 218	$ 208
Contingent rentals	**10**	6	—
Total	**239**	224	208
Less rental income on properties subleased to others	**48**	54	50
Net rental expense	**$ 191**	$ 170	$ 158

NOTE 11 EMPLOYEE BENEFIT PLANS

Texaco Inc. and certain of its non-U.S. subsidiaries sponsor various benefit plans for active employees and retirees. The costs of the savings, health care and life insurance plans relative to employees' active service are shared by the company and its employees, with Texaco's costs for these plans charged to expense as incurred. In addition, accruals for employee benefit plans are provided principally for the unfunded costs of various pension plans, retiree health and life insurance benefits, incentive compensation plans and for separation benefits payable to employees.

Employee Stock Ownership Plans (ESOP)

Effective March 1, 2000, the Employees Savings Plan of Texaco Inc. merged into the Employees Thrift Plan of Texaco Inc. Participants of the Employees Savings Plan became participants in the Employees Thrift Plan, and the Savings Plan assets were transferred to the Thrift Plan on May 31, 2000.

We recorded ESOP expense of $1 million in 2000, $3 million in 1999 and $1 million in 1998. Our contributions to the Employees Thrift Plan and the Employees Savings Plan amounted to $1 million in 2000, $3 million in 1999 and $1 million in 1998. These plans were designed to provide participants with a benefit of approximately 6% of base pay, as well as any benefits earned under the current employee Performance Compensation Program. In December 2000, we made a $14 million advanced company ESOP allocation for the period December 2000 through May 2001 to entitled participants of the Employees Thrift Plan.

During 2000, we paid $20 million in dividends. Dividends on the common ESOP shares used to service debt of the plans are tax deductible to the company.

The trustee applied the dividends to fund interest payments which amounted to $1 million, $2 million and $5 million for 2000, 1999 and 1998, as well as to reduce principal on the Thrift Plan ESOP loan. In November 1998 and December 1997, a portion of the original loan was refinanced through a company loan. The Thrift Plan ESOP loan was satisfied in December 2000.

Benefit Plan Trust

We have established a benefit plan trust for funding company obligations under some of our benefit plans. At year-end 2000, the trust contained 9.2 million shares of treasury stock. We intend to continue to pay our obligations under our benefit plans. The trust will use the shares, proceeds from the sale of such shares and dividends on such shares to pay benefits only to the extent that we do not pay such benefits. The trustee will vote the shares held in the trust as instructed by the trust's beneficiaries. The shares held by the trust are not considered outstanding for earnings per share purposes until distributed or sold by the trust in payment of benefit obligations.

Termination Benefits

In the fourth quarter of 1998, we announced we were restructuring several of our operations. The principal units affected were our worldwide upstream; our international downstream, principally our marketing operations in the United Kingdom and Brazil and our refining operations in Panama; our global gas marketing operations, now included as part of our global gas, power and energy technology segment; and our corporate center. In 1998, we recorded an after-tax charge of $80 million for employee separations, curtailment costs and special termination benefits associated with our restructuring. The charge was comprised of $88 million of operating expenses, $27 million of selling, general and administrative expenses and $35 million in related income tax benefits. We initially estimated that over 1,400 employee reductions worldwide would occur. In the second quarter of 1999, we expanded the employee separation programs and recorded an after-tax charge of $31 million to cover an additional 1,200 employee reductions. The charge was comprised of $36 million of operating expenses, $12 million of selling, general and administrative expenses and $17 million in related income tax benefits. By the end of the third quarter of 2000, we had satisfied all remaining obligations in accordance with plan provisions. Cash payments totaled $151 million and transfers to long-term obligations totaled $12 million. Employee reductions approximated the original estimates.

During the first quarter of 2000, we announced an additional employee separation program for our international downstream, primarily our marketing operations in Brazil and Ireland. We recorded an after-tax charge of $12 million for employee separations, curtailment costs and special termination benefits for about 200 employees. The charge was comprised of $17 million of selling, general and administrative expenses and $5 million in related income tax benefits. Through December 31, 2000, employee reductions totaled 159. The remaining reductions will occur by the end of the first quarter of 2001. During the year 2000, we made cash payments of $8 million and transfers to long-term obligations of $8 million. We will pay the remaining obligations of $1 million in future periods in accordance with plan provisions.

Pension Plans

We sponsor pension plans that cover the majority of our employees. Generally, these plans provide defined pension benefits based on years of service, age and final average pay. Pension plan assets are principally invested in equity and fixed income securities and deposits with insurance companies.

Total worldwide expense for all employee pension plans of Texaco, including pension supplementations and smaller non-U.S. plans, was $42 million in 2000, $41 million in 1999 and $92 million in 1998.

The following data are provided for principal U.S. and non-U.S. plans:

	Pension Benefits				Other U.S. Benefits	
	2000		1999			
(Millions of dollars) As of December 31	**U.S.**	**Int'l**	U.S.	Int'l	**2000**	1999
Changes in Benefit (Obligations)						
Benefit (obligations) at January 1	**$ (1,664)**	**$ (980)**	$ (1,884)	$ (979)	**$ (633)**	$ (773)
Service cost	**(35)**	**(24)**	(46)	(25)	**(5)**	(6)
Interest cost	**(120)**	**(75)**	(113)	(82)	**(48)**	(49)
Amendments	**(2)**	**(3)**	(29)	(23)	**—**	12
Actuarial gain (loss)	**(21)**	**(10)**	(16)	(26)	**(104)**	59
Employee contributions	**(2)**	**—**	(3)	(1)	**(18)**	(14)
Benefits paid	**66**	**64**	63	62	**71**	66
Curtailments/settlements	**76**	**3**	364	(2)	**—**	12
Special termination benefits	**—**	**(6)**	—	—	**—**	—
Currency adjustments	**—**	**80**	—	96	**—**	—
Acquisitions/joint ventures	**—**	**—**	—	—	**—**	60
Benefit (obligations) at December 31	**$ (1,702)**	**$ (951)**	$ (1,664)	$ (980)	**$ (737)**	$ (633)
Changes in Plan Assets						
Fair value of plan assets at January 1	**$ 1,646**	**$ 1,070**	$ 1,826	$ 1,028	**$ —**	$ —
Actual return on plan assets	**(41)**	**19**	236	151	**—**	—
Company contributions	**18**	**22**	15	26	**53**	52
Employee contributions	**2**	**—**	3	1	**18**	14
Expenses	**(8)**	**—**	(7)	—	**—**	—
Benefits paid	**(66)**	**(64)**	(63)	(62)	**(71)**	(66)
Currency adjustments	**—**	**(73)**	—	(74)	**—**	—
Curtailments/settlements	**(76)**	**—**	(364)	—	**—**	—
Fair value of plan assets at December 31	**$ 1,475**	**$ 974**	$ 1,646	$ 1,070	**$ —**	$ —
Funded Status of the Plans						
Obligation (greater than) less than assets	**$ (227)**	**$ 23**	$ (18)	$ 90	**$ (737)**	$ (633)
Unrecognized net transition asset	**(2)**	**—**	(7)	(1)	**—**	—
Unrecognized prior service cost	**73**	**48**	85	63	**(7)**	(7)
Unrecognized actuarial (gain) loss	**68**	**85**	(161)	(17)	**(32)**	(143)
Net (liability) asset recorded in Texaco's Consolidated Balance Sheet	**$ (88)**	**$ 156**	$ (101)	$ 135	**$ (776)**	$ (783)
Net (liability) asset recorded in Texaco's Consolidated Balance Sheet consists of:						
Prepaid benefit asset	**$ 27**	**$ 392**	$ 84	$ 373	**$ —**	$ —
Accrued benefit liability	**(158)**	**(248)**	(231)	(246)	**(776)**	(783)
Intangible asset	**16**	**12**	23	8	**—**	—
Other comprehensive income	**27**	**—**	23	—	**—**	—
Net (liability) asset recorded in Texaco's Consolidated Balance Sheet	**$ (88)**	**$ 156**	$ (101)	$ 135	**$ (776)**	$ (783)
Assumptions as of December 31						
Discount rate	**7.5%**	**7.8%**	8.0%	8.1%	**7.5%**	8.0%
Expected return on plan assets	**10.0%**	**8.8%**	10.0%	8.8%	**—**	—
Rate of compensation increase	**4.0%**	**4.5%**	4.0%	5.2%	**4.0%**	4.0%
Health care cost trend rate	**—**	**—**	—	—	**4.0%**	4.0%

(Millions of dollars) As of December 31	Pension Benefits 2000 U.S.	2000 Int'l	1999 U.S.	1999 Int'l	1998 U.S.	1998 Int'l	Other U.S. Benefits 2000	1999	1998
Components of Net Periodic Benefit Expenses									
Service cost	**$ 35**	**$ 24**	$ 46	$ 25	$ 60	$ 21	**$ 5**	$ 6	$ 9
Interest cost	**120**	**75**	113	82	117	86	**48**	49	50
Expected return on plan assets	**(136)**	**(96)**	(140)	(81)	(136)	(79)	**—**	—	—
Amortization of transition asset	**(5)**	**(1)**	(6)	(12)	(4)	(10)	**—**	—	—
Amortization of prior service cost	**14**	**9**	11	13	11	7	**(1)**	—	—
Amortization of (gain) loss	**1**	**(3)**	4	(2)	6	(2)	**(7)**	(1)	(4)
Curtailments/settlements	**(7)**	**8**	(15)	2	6	—	**—**	(12)	1
Special termination charges	**—**	**—**	—	—	8	—	**—**	—	2
Net periodic benefit expenses	**$ 22**	**$ 16**	$ 13	$ 27	$ 68	$ 23	**$ 45**	$ 42	$ 58

For pension plans with accumulated obligations in excess of plan assets, the projected benefit obligation and the accumulated benefit obligation were $410 million and $390 million as of December 31, 2000, and $410 million and $379 million as of December 31, 1999. The fair value of plan assets for both years was $0.

Other U.S. Benefits

We sponsor postretirement plans in the U.S. that provide health care and life insurance for retirees and eligible dependents based on an age and service point schedule for eligible participants. Our U.S. health insurance obligation is our fixed dollar contribution. The plans are unfunded, and the costs are shared by us and our employees and retirees. Certain of the company's non-U.S. subsidiaries have postretirement benefit plans, the cost of which is not significant to the company.

For measurement purposes, the fixed dollar contribution is expected to increase by 4% per annum for all future years. A change in our fixed dollar contribution has a significant effect on the amounts we report. A 1% change in our contributions would have the following effects:

(Millions of dollars)	1-Percentage Point Increase	1-Percentage Point Decrease
Effect on annual total of service and interest cost components	$ 4	$ (4)
Effect on postretirement benefit obligation	$ 46	$ (41)

NOTE 12 STOCK INCENTIVE PLAN

Under our Stock Incentive Plan, stock options, restricted stock and other incentive award forms may be granted to executives, directors and key employees to provide motivation to enhance the company's success and increase shareholder value. The maximum number of shares that may be awarded as stock options or restricted stock under the plan is 1% of the common stock outstanding on December 31 of the previous year. The following table summarizes the number of shares at December 31, 2000, 1999 and 1998 available for awards during the subsequent year:

(Shares) As of December 31	2000	1999	1998
To all participants	**19,803,026**	15,646,336	12,677,325
To those participants not officers or directors	**229,229**	2,020,621	1,967,715
Total	**20,032,255**	17,666,957	14,645,040

Restricted shares granted under the plan contain a performance element which must be satisfied in order for all or a specified portion of the shares to vest. Restricted performance shares awarded in each year under the plan were as follows:

	2000	1999	1998
Shares	**530,878**	278,402	334,798
Weighted average fair value	**$ 56.52**	$ 62.78	$ 61.59

Stock options granted under the plan extend for 10 years from the date of grant and vest over a two-year period at a rate of 50% in the first year and 50% in the second year. The exercise price cannot be less than the fair market value of the underlying shares of common stock on the date of the grant. The plan provides for restored options. This feature enables a participant who exercises a stock option by exchanging previously acquired common stock or who has shares withheld by us to satisfy tax withholding obligations, to receive new options equal to the number of shares exchanged or withheld. The restored options are fully exercisable six months after the date of grant and the exercise price is the fair market value of the common stock on the day the restored option is granted.

We apply APB Opinion 25 in accounting for our stock-based compensation programs. Stock-based compensation expense recognized in connection with the plan was $25 million in 2000, $19 million in 1999 and $17 million in 1998. Had we accounted for our plan using the accounting method recommended by SFAS 123, net income and earnings per share would have been the pro forma amounts below:

	2000	1999	1998
Net income *(millions of dollars)*			
As reported	**$ 2,542**	$ 1,177	$ 578
Pro forma	**$ 2,525**	$ 1,107	$ 524
Earnings per share *(dollars)*			
Basic — as reported	**$ 4.66**	$ 2.14	$ .99
— pro forma	**$ 4.63**	$ 2.01	$ .89
Diluted — as reported	**$ 4.65**	$ 2.14	$ .99
— pro forma	**$ 4.62**	$ 2.01	$ .89

We used the Black-Scholes model with the following assumptions to estimate the fair market value of options at date of grant:

	2000	1999	1998
Expected life	**2 yrs.**	2 yrs.	2 yrs.
Interest rate	**6.4%**	5.4%	5.4%
Volatility	**33.8%**	29.1%	22.5%
Dividend yield	**3.0%**	3.0%	3.0%

Option award activity during 2000, 1999 and 1998 is summarized in the following table:

	2000		1999		1998	
(Stock options)	**Shares**	**Weighted Average Exercise Price**	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding January 1	**12,097,138**	**$ 62.98**	11,616,049	$ 59.48	10,071,307	$ 53.31
Granted	**2,611,142**	**56.51**	2,015,741	62.78	2,388,593	61.56
Exercised	**(696,136)**	**55.42**	(8,163,386)	59.24	(7,732,978)	53.18
Restored	**592,820**	**60.38**	7,448,018	64.55	6,889,941	60.77
Canceled	**(885,326)**	**64.29**	(819,284)	64.48	(814)	78.08
Outstanding December 31	**13,719,638**	**61.95**	12,097,138	62.98	11,616,049	59.48
Exercisable December 31	**9,657,813**	**$ 63.35**	6,358,652	$ 62.57	5,945,445	$ 58.93
Weighted average fair value of options granted during the year		**$ 11.56**		$ 11.21		$ 8.48

The following table summarizes information on stock options outstanding at December 31, 2000:

	Options Outstanding			Options Exercisable	
Exercisable Price Range (per share)	**Shares**	**Weighted Average Remaining Life**	**Weighted Average Exercise Price**	**Shares**	**Weighted Average Exercise Price**
$ 29.88 – 31.84	**8,112**	**2.4 yrs.**	**$ 31.14**	**8,112**	**$ 31.14**
$ 33.16 – 68.44	**13,711,526**	**6.3 yrs.**	**$ 61.97**	**9,649,701**	**$ 63.38**
$ 29.88 – 68.44	**13,719,638**	**6.3 yrs.**	**$ 61.95**	**9,657,813**	**$ 63.35**

NOTE 13 PREFERRED STOCK AND RIGHTS

Series B ESOP Convertible Preferred Stock

On June 30, 1999, after we called the Series B for redemption, each share of Series B was converted into 25.736 shares, or 15.1 million shares in total, of common stock.

Series D Junior Participating Preferred Stock and Rights

In 1989, we declared a dividend distribution of one Right for each outstanding share of common stock. This was adjusted to one-half Right when we declared a two-for-one stock split in 1997. In 1998, our shareholders approved the extension of the Rights until May 1, 2004. Unless we redeem the Rights, the Rights will be exercisable only after a person(s) acquires, obtains the right to acquire or commences a tender offer that would result in that person(s) acquiring 20% or more of the outstanding common stock other than pursuant to a Qualifying Offer. A Qualifying Offer is an all-cash, fully financed tender offer for all outstanding shares of common stock which remains open for 45 days, which results in the acquiror owning a majority of the company's voting stock, and in which the acquiror agrees to purchase for cash all remaining shares of common stock. The Rights entitle holders to purchase from the company units of Series D Junior Participating Preferred Stock (Series D). In general, each Right entitles the holder to acquire shares of Series D, or in certain cases common stock, property or other securities, at a formula value equal to two times the exercise price of the Right.

We can redeem the Rights at one cent per Right at any time prior to 10 days after the Rights become exercisable. Until a Right becomes exercisable, the holder has no additional voting or dividend rights and it will not have any dilutive effect on the company's earnings. We have reserved and designated 3 million shares as Series D for issuance upon exercise of the Rights. At December 31, 2000, the Rights were not exercisable. The Rights will not become exercisable if the proposed merger between Chevron and Texaco is completed in accordance with the terms and conditions of the Merger Agreement dated October 15, 2000.

Series F ESOP Convertible Preferred Stock

On February 16, 1999, after we called the Series F for redemption, each share of Series F was converted into 20 shares, or 1.1 million shares in total, of common stock.

Market Auction Preferred Shares

There are 1,200 shares of cumulative variable rate preferred stock, called Market Auction Preferred Shares (MAPS) outstanding. The MAPS are grouped into four series (300 shares each of Series G, H, I and J) of $75 million each, with an aggregate value of $300 million.

The dividend rates for each series are determined by Dutch auctions conducted at seven-week or longer intervals.

During 2000, the annual dividend rate for the MAPS ranged between 4.22% and 5.15% and dividends totaled $17 million ($14,189, $14,307, $14,301 and $12,823 per share for series G, H, I and J).

For 1999, the annual dividend rate for the MAPS ranged between 3.59% and 4.36% and dividends totaled $9 million ($7,713, $7,772, $7,989 and $7,935 per share for Series G, H, I and J).

For 1998, the annual dividend rate for the MAPS ranged between 3.96% and 4.50% and dividends totaled $13 million ($11,280, $11,296, $11,227 and $11,218 per share for Series G, H, I and J).

We may redeem the MAPS, in whole or in part, at any time at a liquidation preference of $250,000 per share, plus premium, if any, and accrued and unpaid dividends thereon.

The MAPS are non-voting, except under limited circumstances.

NOTE 14 FINANCIAL INSTRUMENTS

We utilize various types of financial instruments in conducting our business. Financial instruments encompass assets and liabilities included in the balance sheet, as well as derivatives which are principally off-balance sheet.

Derivatives are contracts whose value is derived from changes in an underlying commodity price, interest rate or other item. We use derivatives to reduce our exposure to changes in foreign exchange rates, interest rates and crude oil, petroleum products and natural gas prices. Our written policies restrict our use of derivatives to primarily protecting existing positions and committed or anticipated transactions. On a limited basis, we may use commodity-based derivatives to establish a position in anticipation of future movements in prices or margins. Derivative transactions expose us to counterparty credit risk. We place contracts only with parties whose credit-worthiness has been pre-determined under credit policies and limit the dollar exposure to any counterparty. Therefore, risk of counterparty nonperformance and exposure to concentrations of credit risk are limited.

Cash and Cash Equivalents

Fair value approximates cost as reflected in the Consolidated Balance Sheet at December 31, 2000 and 1999 because of the short-term maturities of these instruments. Cash equivalents are classified as held-to-maturity. The amortized cost of cash equivalents at December 31, 2000 includes $34 million of time deposits and $16 million of commercial paper. Comparable amounts at year-end 1999 were $67 million and $165 million.

Short-Term and Long-Term Investments

Fair value is primarily based on quoted market prices and valuation statements obtained from major financial institutions. At December 31, 2000, our available-for-sale securities had an estimated fair value of $168 million, including gross unrealized gains of $9 million and losses of $5 million. At December 31, 1999, our available-for-sale securities had an estimated fair value of $167 million, including gross unrealized gains of $11 million and losses of $6 million. The available-for-sale securities consist primarily of debt securities issued by U.S. and foreign governments and corporations. The majority of these investments mature within five years.

Proceeds from sales of available-for-sale securities were $224 million in 2000, $750 million in 1999 and $1,011 million in 1998. These sales resulted in gross realized gains of $8 million in 2000, $45 million in 1999 and $53 million in 1998, and gross realized losses of $7 million, $13 million and $22 million.

The estimated fair value of other long-term investments qualifying as financial instruments but not included above, for which it is practicable to estimate fair value, approximated the December 31, 2000 and 1999 carrying values of $549 million and $465 million.

Short-Term Debt, Long-Term Debt and Related Derivatives

Refer to Note 9 for additional information about debt and related derivatives outstanding at December 31, 2000 and 1999.

Forward Exchange and Option Contracts

As an international company, we are exposed to currency exchange risk. To hedge against adverse changes in foreign currency exchange rates, we will enter into forward and option contracts to buy and sell foreign currencies. Shown below in U.S. dollars are the notional amounts of outstanding forward exchange contracts to buy and sell foreign currencies.

(Millions of dollars)	Buy	Sell
Australian dollars	**$ 230**	**$ 31**
British pounds	**856**	**365**
Danish kroner	**215**	**90**
Euro	**293**	**92**
New Zealand dollars	**117**	**26**
Other currencies	**59**	**26**
Total at December 31, 2000	**$ 1,770**	**$ 630**
Total at December 31, 1999	$ 2,122	$ 272

Market risk exposure on these contracts is essentially limited to currency rate movements. At year-end 2000, there were $58 million of unrealized gains and $2 million of unrealized losses related to these contracts. At year-end 1999, there were $10 million of unrealized gains and $30 million of unrealized losses.

We use forward exchange contracts to buy foreign currencies primarily to hedge the net monetary liability position of our European, Australian and New Zealand operations and to hedge portions of significant foreign currency capital expenditures and lease commitments. These contracts generally have terms of 60 days or less. Contracts that hedge foreign currency monetary positions are marked-to-market monthly. Any resultant gains and losses are included in the Consolidated Statement of Income as other costs. At year-end 2000 and 1999, hedges of foreign currency commitments principally involved capital projects requiring expenditure of British pounds and Danish kroner. The percentages of planned capital expenditures hedged at year end were: British pounds — 72% in 2000 and 90% in 1999; Danish kroner — 87% in 2000 and 94% in 1999. Realized gains and losses on hedges of foreign currency commitments are initially recorded to deferred charges. Subsequently, the amounts are applied to the capitalized project cost on a percentage-of-completion basis, and are then amortized over the lives of the applicable projects. At year-end 2000 and 1999, net hedging losses of $18 million and net hedging gains of $17 million had yet to be amortized.

We sell foreign currencies under a separately managed program to hedge the value of our investment portfolio denominated in foreign currencies. Our strategy is to hedge the full value of this portion of our investment portfolio and to close out forward contracts upon the sale or maturity of the corresponding investments. We value these contracts at market based on the foreign exchange rates in effect on the balance sheet dates. We record changes in the value of these contracts as part of the carrying amount of the related investments. We record related gains and losses, net of applicable income taxes, to stockholders' equity until the underlying investments are sold or mature.

Preferred Shares of Subsidiaries

Refer to Note 15 regarding derivatives related to subsidiary preferred shares.

Petroleum and Natural Gas Hedging

We hedge a portion of the market risks associated with our crude oil, natural gas and petroleum product purchases, sales and exchange activities to reduce price exposure. All hedge transactions are subject to the company's corporate risk management policy which sets out dollar, volumetric and term limits, as well as to management approvals as set forth in our delegations of authorities.

We use established petroleum futures exchanges, as well as "over-the-counter" hedge instruments, including futures, options, swaps and other derivative products. In carrying out our hedging programs, we analyze our major commodity streams for fixed cost, fixed revenue and margin exposure to market price changes. Based on this corporate risk profile, forecasted trends and overall business objectives, we determine an appropriate strategy for risk reduction.

Hedge positions are marked-to-market for valuation purposes. Gains and losses on hedge transactions, which offset losses and gains on the underlying "cash market" transactions, are recorded to deferred income or charges until the hedged transaction is closed, or until the anticipated future purchases, sales or production occur. At that time, any gain or loss on the hedging contract is recorded to operating revenues as an increase or decrease in margins, or to inventory, as appropriate. Derivative transactions not designated as hedging a specific position or transaction are adjusted to market at each balance sheet date. Gains and losses are included in operating income.

At December 31, 2000 and 1999, there were open derivative commodity contracts required to be settled in cash, consisting mostly of basis swaps related to location differences in prices. Notional contract amounts, excluding unrealized gains and losses, were $9,077 million and $6,604 million at year-end 2000 and 1999. These amounts principally represent future values of contract volumes over the remaining duration of outstanding swap contracts at the respective dates. These contracts hedge a small fraction of our business activities, generally for the next 12 months. Unrealized gains and losses on contracts outstanding at year-end 2000 were $641 million and $423 million. At year-end 1999, unrealized gains and losses were $195 million and $132 million.

NOTE 15 OTHER FINANCIAL INFORMATION, COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

Texaco Inc. and subsidiary companies have financial liabilities relating to environmental remediation programs which we believe are sufficient for known requirements. At December 31, 2000, the balance sheet includes liabilities of $260 million for future environmental remediation costs. Also, we have accrued $665 million for the future cost of restoring and abandoning existing oil and gas properties.

We have accrued for our probable environmental remediation liabilities to the extent reasonably measurable. We based our accruals for these obligations on technical evaluations of the currently available facts, interpretation of the regulations and our experience with similar sites. Additional accrual requirements for existing and new remediation sites may be necessary in the future when more facts are known. The potential also exists for further legislation which may provide limitations on liability. It is not possible to project the overall costs or a range of costs for environmental items beyond that disclosed above. This is due to uncertainty surrounding future developments, both in relation to remediation exposure and to regulatory initiatives. We believe that such future costs will not be material to our financial position or to our operating results over any reasonable period of time.

Preferred Shares of Subsidiaries

Minority holders own $602 million of preferred shares of our subsidiary companies, which is reflected as minority interest in subsidiary companies in the Consolidated Balance Sheet.

MVP Production Inc., a subsidiary, has variable rate cumulative preferred shares of $75 million owned by one minority holder. The shares have voting rights and are redeemable in 2003. Dividends on these shares were $4 million in 2000, 1999 and 1998.

Texaco Capital LLC, a wholly-owned finance subsidiary of Texaco Inc., has three classes of preferred shares, all held by minority holders. The first class is 14 million shares totaling $350 million of Cumulative Guaranteed Monthly Income Preferred Shares, Series A (Series A). The second class is 4.5 million shares totaling $112 million of Cumulative Adjustable Rate Monthly Income Preferred Shares, Series B (Series B). The third class, issued in Canadian dollars, is 3.6 million shares totaling $65 million of Deferred Preferred Shares, Series C (Series C). Texaco Capital LLC's sole assets are notes receivable from Texaco Inc. The payment of dividends and payments on liquidation or redemption with respect to Series A, Series B and Series C are fully and unconditionally guaranteed by Texaco Inc.

The fixed dividend rate for Series A is 6-7/8% per annum. The annual dividend rate for Series B averaged 5.4% for 2000, 5.0% for 1999 and 5.1% for 1998. The dividend rate on Series B is reset quarterly per contractual formula. Dividends on Series A and Series B are paid monthly. Dividends on Series A for 2000, 1999 and 1998 totaled $24 million for each year. Annual dividends on Series B totaled $6 million for 2000, 1999 and 1998.

Series A and Series B are redeemable under certain circumstances at the option of Texaco Capital LLC (with Texaco Inc.'s consent) in whole or in part at $25 per share plus accrued and unpaid dividends to the date fixed for redemption.

Dividends on Series C at a rate of 7.17% per annum, compounded annually, will be paid at the redemption date of February 28, 2005, unless earlier redemption occurs. Early redemption may result upon the occurrence of certain specific events.

We have entered into an interest rate and currency swap related to Series C preferred shares. The swap matures in the year 2005. Over the life of the interest rate swap component of the contract, we will make LIBOR-based floating rate interest payments based on a notional principal amount of $65 million. Canadian dollar interest will accrue to us at a fixed rate applied to the accreted notional principal amount, which was Cdn. $87 million at the inception of the swap.

The currency swap component of the transaction calls for us to exchange at contract maturity date $65 million for Cdn. $170 million, representing Cdn. $87 million plus accrued interest. The carrying amount of this contract represents the Canadian dollar accrued interest receivable by us. At year-end 2000 and 1999, the carrying amounts of this swap, which approximated fair value, were $27 million and $20 million.

Series A, Series B and Series C preferred shares are non-voting, except under limited circumstances.

The above preferred stock issues currently require annual dividend payments of approximately $34 million. We are required to redeem $75 million of this preferred stock in 2003, $65 million (plus accreted dividends of $59 million) in 2005, $112 million in 2024 and $350 million in 2043. We have the ability to extend the required redemption dates for the $112 million and $350 million of preferred stock beyond 2024 and 2043.

Pending Award

In July 1999, the Governing Council of the United Nations Compensation Commission (UNCC) approved an award to Saudi Arabian Texaco Inc. (SAT), a wholly-owned subsidiary of Texaco Inc., of about $505 million, plus unspecified interest, for damages sustained as a result of Iraq's invasion of Kuwait in 1990. Payments to SAT are subject to income tax in Saudi Arabia at an applicable tax rate of 85%. SAT is party to a concession agreement with the Kingdom of Saudi Arabia covering the Partitioned Neutral Zone in Southern Kuwait and Northern Saudi Arabia.

UNCC funds compensation awards by retaining 30% of Iraqi oil sales revenue under an agreement with Iraq. In January 2001, SAT was paid $5 million and expects to be paid an additional $40 million in the near future. We do not know when we will receive the balance of this award since the timing of payments by UNCC depends on several factors, including the total amount of all compensation awards, the ability of Iraq to produce and sell oil, the price of Iraqi oil and the duration of U.N. trade sanctions on Iraq. This award will be recognized in income when collection is assured.

Financial Guarantees

We have guaranteed the payment of certain debt, lease commitments and other obligations of third parties and affiliate companies. These guarantees totaled $792 million and $804 million at December 31, 2000 and 1999. The year-end 2000 and 1999 amounts include $399 million and $424 million of operating lease commitments of Equilon, our affiliate.

Exposure to credit risk in the event of non-payment by the obligors is represented by the contractual amount of these instruments. No loss is anticipated under these guarantees.

Throughput Agreements

Texaco Inc. and certain of its subsidiary companies previously entered into certain long-term agreements wherein we committed to ship through affiliated pipeline companies and an offshore oil port sufficient volume of crude oil or petroleum products to enable these affiliated companies to meet a specified portion of their individual debt obligations, or, in lieu thereof, to advance sufficient funds to enable these affiliated companies to meet these obligations. In 1998, we assigned the shipping obligations to Equilon, our affiliate, but Texaco remains responsible for deficiency payments on virtually all of these agreements. Additionally, Texaco has entered into long-term purchase commitments with third parties for take or pay gas transportation. At December 31, 2000 and 1999, our maximum exposure to loss was estimated to be $388 million and $445 million.

However, based on our right of counterclaim against Equilon and unaffiliated third parties in the event of non-performance, our net exposure was estimated to be $148 million and $173 million at December 31, 2000 and 1999.

No significant losses are anticipated as a result of these obligations.

Litigation

Texaco and approximately 50 other oil companies are defendants in 17 purported class actions. The actions are pending in Texas, New Mexico, Oklahoma, Louisiana, Utah, Mississippi and Alabama. The plaintiffs allege that the defendants undervalued oil produced from properties leased from the plaintiffs by establishing artificially low selling prices. They allege that these low selling prices resulted in the defendants underpaying royalties or severance taxes to them. Plaintiffs seek to recover royalty underpayments and interest. In some cases plaintiffs also seek to recover severance taxes and treble and punitive damages. Texaco and 24 other defendants have executed a settlement agreement with most of the plaintiffs that will resolve many of these disputes. The federal court in Texas gave final approval to the settlement in April 1999 and the matter is now pending before the U.S. Fifth Circuit Court of Appeal.

Texaco has reached an agreement with the federal government to resolve similar claims. The claims of various state governments remain unresolved.

It is impossible for us to ascertain the ultimate legal and financial liability with respect to contingencies and commitments. However, we do not anticipate that the aggregate amount of such liability in excess of accrued liabilities will be materially important in relation to our consolidated financial position or results of operations.

NOTE 16 CHEVRON-TEXACO MERGER

On October 15, 2000, Texaco and Chevron Corporation entered into a merger agreement. In the merger, Texaco shareholders will receive .77 shares of Chevron common stock for each share of Texaco common stock they own, and Chevron shareholders will retain their existing shares.

The merger is conditioned, among other things, on the approval of the shareholders of both companies, pooling of interests accounting treatment for the merger and approvals of government agencies, such as the U.S. Federal Trade Commission (FTC). Texaco and Chevron anticipate that the FTC will require certain divestitures in the U.S. downstream in order to address market concentration issues, and the companies intend to cooperate with the FTC in this process. In that regard, Texaco is in discussions with our partners in the U.S. downstream.

The merger agreement provides for the payment of termination fees of as much as $1 billion by either party under certain circumstances. Chevron and Texaco also were granted options to purchase shares of the other, under the same conditions as the payments of the termination fees. Texaco granted Chevron an option to purchase 107 million shares of Texaco's common stock, at $53.71 per share. Chevron granted Texaco an option to purchase 127 million shares of Chevron's common stock, at $85.96 per share.

REPORT OF MANAGEMENT

We are responsible for preparing Texaco's consolidated financial statements in accordance with generally accepted accounting principles. In doing so, we must use judgment and estimates when the outcome of events and transactions is not certain. Information appearing in other sections of this Annual Report is consistent with the financial statements.

Texaco's financial statements are based on its financial records. We rely on Texaco's internal control system to provide us reasonable assurance these financial records are being accurately and objectively maintained and the company's assets are being protected. The internal control system comprises:

- Corporate Conduct Guidelines requiring all employees to obey all applicable laws, comply with company policies and maintain the highest ethical standards in conducting company business,
- An organizational structure in which responsibilities are defined and divided, and
- Written policies and procedures that cover initiating, reviewing, approving and recording transactions.

We require members of our management team to formally certify each year that the internal controls for their business units are operating effectively.

Texaco's internal auditors review and report on the effectiveness of internal controls during the course of their audits. Arthur Andersen LLP, selected by the Audit Committee and approved by stockholders, independently audits Texaco's financial statements. Arthur Andersen LLP assesses the adequacy and effectiveness of Texaco's internal controls when determining the nature, timing and scope of their audit. We seriously consider all suggestions for improving Texaco's internal controls that are made by the internal and independent auditors.

The Audit Committee is comprised of six directors who are not employees of Texaco. This Committee reviews and evaluates Texaco's accounting policies and reporting practices, internal auditing, internal controls, security and other matters. The Committee also evaluates the independence and professional competence of Arthur Andersen LLP and reviews the results and scope of their audit. The internal and independent auditors have free access to the Committee to discuss financial reporting and internal control issues.

Glenn F. Tilton
Chairman of the Board and Chief Executive Officer

Patrick J. Lynch
Senior Vice President and Chief Financial Officer

George J. Batavick
Comptroller

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Stockholders, Texaco Inc.:
We have audited the accompanying consolidated balance sheet of Texaco Inc. (a Delaware corporation) and subsidiary companies as of December 31, 2000 and 1999, and the related consolidated statements of income, stockholders' equity, comprehensive income and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Texaco Inc. and subsidiary companies as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP
February 22, 2001
New York, N.Y.

SUPPLEMENTAL OIL AND GAS INFORMATION

The following pages provide information required by Statement of Financial Accounting Standards No. 69, "Disclosures about Oil and Gas Producing Activities."

Table I – Net Proved Reserves

The reserve quantities include only those quantities that are recoverable based upon reasonable estimates from sound geological and engineering principles. As additional information becomes available, these estimates may be revised. Also, we have a large inventory of potential hydrocarbon resources that we expect will increase our reserve base as future investments are made in exploration and development programs.

- Proved *developed* reserves are reserves that we expect to be recovered through existing wells with existing equipment and operating methods.
- Proved *undeveloped* reserves are reserves that we expect to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion of development.

Table I – Net Proved Reserves

Net Proved Reserves of Crude Oil and Natural Gas Liquids *(Millions of barrels)*

	Consolidated Subsidiaries					Equity			
	United States	Other West	Europe	Other East	Total	Affiliate – Other West	Affiliate – Other East	Total	World-wide
Developed reserves	1,374	54	210	463	2,101	—	354	354	2,455
Undeveloped reserves	393	11	221	90	715	—	97	97	812
As of December 31, 1997	1,767	65	431	553	2,816	—	451	451	3,267
Discoveries & extensions	70	2	8	32	112	—	1	1	113
Improved recovery	136	—	16	3	155	—	156	156	311
Revisions	46	(15)	22	55	108	—	137	137	245
Net purchases (sales)	(38)	—	—	26	(12)	—	—	—	(12)
Production	(157)	(4)	(58)	(71)	(290)	—	(61)	(61)	(351)
Total changes	57	(17)	(12)	45	73	—	233	233	306
Developed reserves	1,415	39	246	490	2,190	—	456	456	2,646
Undeveloped reserves	409	9	173	108	699	—	228	228	927
As of December 31, 1998*	1,824	48	419	598	2,889	—	684	684	3,573
Discoveries & extensions	66	11	23	23	123	—	2	2	125
Improved recovery	34	—	2	29	65	—	52	52	117
Revisions	11	—	36	72	119	—	(132)	(132)	(13)
Net purchases (sales)	(9)	—	—	23	14	—	—	—	14
Production	(144)	(4)	(53)	(75)	(276)	—	(60)	(60)	(336)
Total changes	(42)	7	8	72	45	—	(138)	(138)	(93)
Developed reserves	1,361	39	261	545	2,206	—	316	316	2,522
Undeveloped reserves	421	16	166	125	728	—	230	230	958
As of December 31, 1999*	1,782	55	427	670	2,934	—	546	546	3,480
Discoveries & extensions	**39**	**—**	**21**	**9**	**69**	**374**	**—**	**374**	**443**
Improved recovery	**25**	**—**	**—**	**39**	**64**	**—**	**14**	**14**	**78**
Revisions	**(21)**	**—**	**9**	**30**	**18**	**—**	**37**	**37**	**55**
Net purchases (sales)	**(135)**	**(52)**	**(44)**	**—**	**(231)**	**—**	**—**	**—**	**(231)**
Production	**(130)**	**(3)**	**(44)**	**(78)**	**(255)**	**—**	**(52)**	**(52)**	**(307)**
Total changes	**(222)**	**(55)**	**(58)**	**—**	**(335)**	**374**	**(1)**	**373**	**38**
Developed reserves	**1,202**	**—**	**219**	**559**	**1,980**	**—**	**282**	**282**	**2,262**
Undeveloped reserves	**358**	**—**	**150**	**111**	**619**	**374**	**263**	**637**	**1,256**
As of December 31, 2000*	**1,560**	**—**	**369**	**670**	**2,599**	**374**	**545**	**919**	**3,518**
*Includes net proved NGL reserves									
As of December 31, 1998	250	—	68	22	340	—	6	6	346
As of December 31, 1999	250	—	74	134	458	—	1	1	459
As of December 31, 2000	**219**	**—**	**67**	**162**	**448**	**—**	**1**	**1**	**449**

Table I – Net Proved Reserves (continued)

Net Proved Reserves of Natural Gas *(Billions of cubic feet)*

	Consolidated Subsidiaries					Equity			
	United States	Other West	Europe	Other East	Total	Affiliate – Other West	Affiliate – Other East	Total	World-wide
Developed reserves	3,379	792	576	110	4,857	—	145	145	5,002
Undeveloped reserves	643	126	452	2	1,223	—	17	17	1,240
As of December 31, 1997	4,022	918	1,028	112	6,080	—	162	162	6,242
Discoveries & extensions	599	6	47	98	750	—	1	1	751
Improved recovery	4	—	7	—	11	—	3	3	14
Revisions	152	(12)	(6)	34	168	—	10	10	178
Net purchases (sales)	(39)	—	—	250	211	—	—	—	211
Production	(633)	(92)	(112)	(17)	(854)	—	(25)	(25)	(879)
Total changes	83	(98)	(64)	365	286	—	(11)	(11)	275
Developed reserves	3,345	688	615	374	5,022	—	135	135	5,157
Undeveloped reserves	760	132	349	103	1,344	—	16	16	1,360
As of December 31, 1998	4,105	820	964	477	6,366	—	151	151	6,517
Discoveries & extensions	442	7	93	42	584	—	5	5	589
Improved recovery	4	—	2	235	241	—	1	1	242
Revisions	285	193	7	427	912	—	3	3	915
Net purchases (sales)	(81)	—	—	712	631	—	—	—	631
Production	(550)	(79)	(104)	(27)	(760)	—	(26)	(26)	(786)
Total changes	100	121	(2)	1,389	1,608	—	(17)	(17)	1,591
Developed reserves	3,388	865	557	787	5,597	—	131	131	5,728
Undeveloped reserves	817	76	405	1,079	2,377	—	3	3	2,380
As of December 31, 1999	4,205	941	962	1,866	7,974	—	134	134	8,108
Discoveries & extensions	**585**	**—**	**—**	**—**	**585**	**33**	**4**	**37**	**622**
Improved recovery	**5**	**—**	**—**	**—**	**5**	**—**	**—**	**—**	**5**
Revisions	**121**	**12**	**43**	**164**	**340**	**—**	**8**	**8**	**348**
Net purchases (sales)	**8**	**(58)**	**(11)**	**—**	**(61)**	**—**	**—**	**—**	**(61)**
Production	**(494)**	**(95)**	**(81)**	**(36)**	**(706)**	**—**	**(24)**	**(24)**	**(730)**
Total changes	**225**	**(141)**	**(49)**	**128**	**163**	**33**	**(12)**	**21**	**184**
Developed reserves	**3,299**	**738**	**573**	**977**	**5,587**	**—**	**121**	**121**	**5,708**
Undeveloped reserves	**1,131**	**62**	**340**	**1,017**	**2,550**	**33**	**1**	**34**	**2,584**
As of December 31, 2000	**4,430**	**800***	**913**	**1,994**	**8,137***	**33**	**122**	**155**	**8,292***

* Additionally, there are approximately 302 BCF of natural gas in Other West which will be available from production during the period 2005-2016 under a long-term purchase associated with a service agreement.

The following chart summarizes our experience in finding new quantities of oil and gas to replace our production. Our reserve replacement performance is calculated by dividing our reserve additions by our production. Our additions relate to new discoveries, existing reserve extensions, improved recoveries and revisions to previous reserve estimates. The chart excludes oil and gas quantities from purchases and sales.

	Worldwide	United States	International
Year 2000	**172%**	**76%**	**267%**
Year 1999	111%	99%	124%
Year 1998	166%	144%	191%
3-year average	150%	109%	192%
5-year average	146%	108%	189%

Table II – Standardized Measure

The standardized measure provides a common benchmark among those companies that have exploration and producing activities. This measure may not necessarily match our view of the future cash flows from our proved reserves.

The standardized measure is calculated at a 10% discount. Future revenues are based on year-end prices for oil and gas. Future production and development costs are based on current year costs. Extensive judgment is used to estimate the timing of production and future costs over the remaining life of the reserves. Future income taxes are calculated using each country's statutory tax rate.

Our inventory of potential hydrocarbon resources, which may become proved in the future, are excluded. This could significantly impact our standardized measure in the future.

Table II – Standardized Measure of Discounted Future Net Cash Flows

	Consolidated Subsidiaries					Equity			
(Millions of dollars)	United States	Other West	Europe	Other East	Total	Affiliate – Other West	Affiliate – Other East	Total	World-wide
As of December 31, 2000									
Future cash inflows from sale of oil & gas, and service fee revenue	**$ 67,115**	**$ 1,559**	**$ 10,549**	**$ 15,512**	**$ 94,735**	**$ 3,917**	**$ 7,873**	**$ 11,790**	**$ 106,525**
Future production costs	**(13,107)**	**(252)**	**(2,074)**	**(2,768)**	**(18,201)**	**(273)**	**(2,853)**	**(3,126)**	**(21,327)**
Future development costs	**(3,588)**	**(30)**	**(1,244)**	**(1,280)**	**(6,142)**	**(406)**	**(694)**	**(1,100)**	**(7,242)**
Future income tax expense	**(17,024)**	**(612)**	**(2,238)**	**(6,681)**	**(26,555)**	**(1,101)**	**(2,189)**	**(3,290)**	**(29,845)**
Net future cash flows before discount	**33,396**	**665**	**4,993**	**4,783**	**43,837**	**2,137**	**2,137**	**4,274**	**48,111**
10% discount for timing of future cash flows	**(15,407)**	**(259)**	**(1,778)**	**(2,239)**	**(19,683)**	**(1,431)**	**(809)**	**(2,240)**	**(21,923)**
Standardized measure of discounted future net cash flows	**$ 17,989**	**$ 406**	**$ 3,215**	**$ 2,544**	**$ 24,154**	**$ 706**	**$ 1,328**	**$ 2,034**	**$ 26,188**
As of December 31, 1999									
Future cash inflows from sale of oil & gas, and service fee revenue	$ 45,281	$ 2,668	$ 11,875	$ 16,890	$ 76,714	$ —	$ 7,646	$ 7,646	$ 84,360
Future production costs	(10,956)	(913)	(2,264)	(2,946)	(17,079)	—	(2,254)	(2,254)	(19,333)
Future development costs	(3,853)	(239)	(1,749)	(1,956)	(7,797)	—	(767)	(767)	(8,564)
Future income tax expense	(8,304)	(758)	(2,428)	(7,665)	(19,155)	—	(2,340)	(2,340)	(21,495)
Net future cash flows before discount	22,168	758	5,434	4,323	32,683	—	2,285	2,285	34,968
10% discount for timing of future cash flows	(10,816)	(327)	(1,985)	(2,243)	(15,371)	—	(887)	(887)	(16,258)
Standardized measure of discounted future net cash flows	$ 11,352	$ 431	$ 3,449	$ 2,080	$ 17,312	$ —	$ 1,398	$ 1,398	$ 18,710
As of December 31, 1998									
Future cash inflows from sale of oil & gas, and service fee revenue	$ 23,147	$ 1,657	$ 6,581	$ 4,816	$ 36,201	$ —	$ 4,708	$ 4,708	$ 40,909
Future production costs	(10,465)	(605)	(2,574)	(2,551)	(16,195)	—	(1,992)	(1,992)	(18,187)
Future development costs	(4,055)	(142)	(1,695)	(761)	(6,653)	—	(803)	(803)	(7,456)
Future income tax expense	(2,583)	(419)	(715)	(1,023)	(4,740)	—	(967)	(967)	(5,707)
Net future cash flows before discount	6,044	491	1,597	481	8,613	—	946	946	9,559
10% discount for timing of future cash flows	(2,626)	(244)	(644)	(167)	(3,681)	—	(391)	(391)	(4,072)
Standardized measure of discounted future net cash flows	$ 3,418	$ 247	$ 953	$ 314	$ 4,932	$ —	$ 555	$ 555	$ 5,487

Table III – Changes in the Standardized Measure

The annual change in the standardized measure is explained in this table by the major sources of change, discounted at 10%.

- *Sales & transfers, net of production costs* capture the current year's revenues less the associated producing expenses. The net amount reflected here correlates to Table VII for revenues less production costs.
- *Net changes in prices, production & development costs* are computed before the effects of changes in quantities. The beginning-of-the-year production forecast is multiplied by the net annual change in the unit sales price and production cost.
- *Discoveries & extensions* indicate the value of the new reserves at year-end prices, less related costs.
- *Development costs incurred during the period* capture the current year's development costs that are shown in Table V. These costs will reduce the previously estimated future development costs.
- *Accretion of discount* represents 10% of the beginning discounted future net cash flows before income tax effects.
- *Net change in income taxes* is computed as the change in present value of future income taxes.

Table III – Changes in the Standardized Measure

	Worldwide Including Equity in Affiliates		
(Millions of dollars)	**2000**	1999	1998
Standardized measure – beginning of year	**$ 18,710**	$ 5,487	$ 12,057
Sales of minerals-in-place	**(3,990)**	(352)	(160)
	14,720	5,135	11,897
Changes in ongoing oil and gas operations:			
Sales and transfers of produced oil and gas, net of production costs during the period	**(7,345)**	(4,276)	(3,129)
Net changes in prices, production and development costs	**11,389**	22,036	(11,205)
Discoveries and extensions and improved recovery, less related costs	**4,543**	1,821	728
Development costs incurred during the period	**2,043**	1,598	1,770
Timing of production and other changes	**670**	(517)	(1,170)
Revisions of previous quantity estimates	**668**	301	852
Purchases of minerals-in-place	**901**	895	48
Accretion of discount	**3,120**	881	1,916
Net change in discounted future income taxes	**(4,521)**	(9,164)	3,780
Standardized measure – end of year	**$ 26,188**	$ 18,710	$ 5,487

Table IV – Capitalized Costs

Costs of the following assets are capitalized under the "successful efforts" method of accounting. These costs include the activities of Texaco's upstream operations but exclude the crude oil marketing and other non-producing activities. As a result, this table will not correlate to information in Note 6 to the financial statements.

- *Proved properties* include mineral properties with proved reserves, development wells and uncompleted development well costs.
- *Unproved properties* include leaseholds under exploration (even where hydrocarbons were found but not in sufficient quantities to be considered proved reserves) and uncompleted exploratory well costs.
- *Support equipment and facilities* include costs for seismic and drilling equipment, construction and grading equipment, repair shops, warehouses and other supporting assets involved in oil and gas producing activities.
- *The accumulated depreciation, depletion and amortization* represents the portion of the assets that have been charged to expense in prior periods. It also includes provisions for future restoration and abandonment activity.

Table IV – Capitalized Costs

	Consolidated Subsidiaries					Equity			
(Millions of dollars)	United States	Other West	Europe	Other East	Total	Affiliate – Other West*	Affiliate – Other East	Total	World-wide
As of December 31, 2000									
Proved properties	**$ 18,213**	**$ 137**	**$ 3,295**	**$ 3,699**	**$ 25,344**	**$ 66**	**$ 1,370**	**$ 1,436**	**$ 26,780**
Unproved properties	**1,026**	**98**	**58**	**655**	**1,837**	**68**	**265**	**333**	**2,170**
Support equipment and facilities	**257**	**81**	**28**	**135**	**501**	**42**	**906**	**948**	**1,449**
Gross capitalized costs	**19,496**	**316**	**3,381**	**4,489**	**27,682**	**176**	**2,541**	**2,717**	**30,399**
Accumulated depreciation, depletion and amortization	**(12,084)**	**(92)**	**(1,821)**	**(1,508)**	**(15,505)**	**(1)**	**(1,349)**	**(1,350)**	**(16,855)**
Net capitalized costs	**$ 7,412**	**$ 224**	**$ 1,560**	**$ 2,981**	**$ 12,177**	**$ 175**	**$ 1,192**	**$ 1,367**	**$ 13,544**
As of December 31, 1999									
Proved properties	$ 20,364	$ 304	$ 5,327	$ 2,525	$ 28,520	$ —	$ 1,158	$ 1,158	$ 29,678
Unproved properties	983	139	50	619	1,791	—	335	335	2,126
Support equipment and facilities	441	267	37	277	1,022	—	902	902	1,924
Gross capitalized costs	21,788	710	5,414	3,421	31,333	—	2,395	2,395	33,728
Accumulated depreciation, depletion and amortization	(13,855)	(298)	(3,955)	(1,365)	(19,473)	—	(1,217)	(1,217)	(20,690)
Net capitalized costs	$ 7,933	$ 412	$ 1,459	$ 2,056	$ 11,860	$ —	$ 1,178	$ 1,178	$ 13,038

*Existing costs were transferred from a consolidated subsidiary to an affiliate at year-end 2000.

Table V – Costs Incurred

This table summarizes how much we spent to explore and develop our existing reserve base, and how much we spent to acquire mineral rights from others (classified as proved or unproved).

- *Exploration costs* include geological and geophysical costs, the cost of carrying and retaining undeveloped properties and exploratory drilling costs.
- *Development costs* include the cost of drilling and equipping development wells and constructing related production facilities for extracting, treating, gathering and storing oil and gas from proved reserves.
- *Exploration and development costs* may be capitalized or expensed, as applicable. Such costs also include administrative expenses and depreciation applicable to support equipment associated with these activities. As a result, the costs incurred will not correlate to *Capital and Exploratory Expenditures.*

On a worldwide basis, in 2000 we spent $3.62 for each BOE we added. Finding and development costs averaged $3.74 for the three-year period 1998-2000 and $3.92 per BOE for the five-year period 1996-2000.

Table V – Costs Incurred

	Consolidated Subsidiaries					Equity			
(Millions of dollars)	United States	Other West	Europe	Other East	Total	Affiliate – Other West	Affiliate – Other East	Total	World-wide
For the year ended December 31, 2000									
Proved property acquisition	**$ 138**	**$ —**	**$ —**	**$ 276**	**$ 414**	**$ —**	**$ —**	**$ —**	**$ 414**
Unproved property acquisition	**5**	**12**	**—**	**—**	**17**	**—**	**—**	**—**	**17**
Exploration	**227**	**62**	**18**	**287**	**594**	**—**	**19**	**19**	**613**
Development	**716**	**121**	**334**	**677**	**1,848**	**—**	**169**	**169**	**2,017**
Total	**$ 1,086**	**$ 195**	**$ 352**	**$ 1,240**	**$ 2,873**	**$ —**	**$ 188**	**$ 188**	**$ 3,061**
For the year ended December 31, 1999									
Proved property acquisition	$ 4	$ —	$ —	$ 481	$ 485	$ —	$ —	$ —	$ 485
Unproved property acquisition	39	25	—	27	91	—	—	—	91
Exploration	204	92	23	224	543	—	19	19	562
Development	698	97	319	301	1,415	—	183	183	1,598
Total	$ 945	$ 214	$ 342	$ 1,033	$ 2,534	$ —	$ 202	$ 202	$ 2,736
For the year ended December 31, 1998									
Proved property acquisition	$ 27	$ —	$ —	$ 199	$ 226	$ —	$ —	$ —	$ 226
Unproved property acquisition	85	1	—	32	118	—	—	—	118
Exploration	417	92	65	277	851	—	19	19	870
Development	1,073	25	308	204	1,610	—	160	160	1,770
Total	$ 1,602	$ 118	$ 373	$ 712	$ 2,805	$ —	$ 179	$ 179	$ 2,984

Table VI – Unit Prices

Average sales prices are calculated using the gross revenues in Table VII. Average lifting costs equal production costs and the depreciation, depletion and amortization of support equipment and facilities, adjusted for inventory changes.

	Average sales prices					
	United States	Other West	Europe	Other East	Affiliate – Other West	Affiliate – Other East
Crude oil *(per barrel)*						
2000	**$ 26.20**	**$ 22.74**	**$ 26.86**	**$ 22.81**	**$ —**	**$ 21.52**
1999	14.97	14.12	17.15	15.33	—	13.24
1998	10.40	9.65	11.73	9.61	—	9.81
Natural gas liquids *(per barrel)*						
2000	**18.73**	**—**	**17.93**	**—**	**—**	**—**
1999	10.86	—	12.53	—	—	—
1998	8.99	—	11.89	—	—	—
Natural gas *(per thousand cubic feet)*						
2000	**3.67**	**1.13**	**2.49**	**1.23**	**—**	**—**
1999	2.07	.77	1.99	.18	—	—
1998	1.93	.92	2.42	.38	—	—

	Average lifting costs *(per barrel of oil equivalent)*					
	United States	Other West	Europe	Other East	Affiliate – Other West	Affiliate – Other East
2000	**$ 5.05**	**$ 2.94**	**$ 5.08**	**$ 3.03**	**$ —**	**$ 5.06**
1999	4.01	2.87	6.15	3.45	—	3.95
1998	4.07	1.86	5.24	3.65	—	2.68

Table VII – Results of Operations

Results of operations for exploration and production activities consist of all the activities within our upstream operations, except for crude oil marketing and other non-producing activities. As a result, this table will not correlate to the *Analysis of Income by Operating Segments.*

- *Revenues* are based upon our production that is available for sale and excludes revenues from resale of third-party volumes, equity earnings of certain smaller affiliates, trading activity and miscellaneous operating income. Expenses are associated with current year operations, but do not include general overhead and special items.
- *Production costs* consist of costs incurred to operate and maintain wells and related equipment and facilities. These costs also include taxes other than income taxes and administrative expenses.
- *Exploration costs* include dry hole, leasehold impairment, geological and geophysical expenses, the cost of retaining undeveloped leaseholds and administrative expenses. Also included are taxes other than income taxes.
- *Depreciation, depletion and amortization* includes the amount for support equipment and facilities.
- *Estimated income taxes* are computed by adjusting each country's income before income taxes for permanent differences related to the oil and gas producing activities, then multiplying the result by the country's statutory tax rate and adjusting for applicable tax credits.

Table VII – Results of Operations

	Consolidated Subsidiaries					Equity			
(Millions of dollars)	United States	Other West	Europe	Other East	Total	Affiliate – Other West	Affiliate – Other East	Total	World-wide
For the year ended December 31, 2000									
Gross revenues from:									
Sales and transfers, including affiliate sales	**$ 4,460**	**$ —**	**$ 869**	**$ 1,440**	**$ 6,769**	**$ —**	**$ 831**	**$ 831**	**$ 7,600**
Sales to unaffiliated entities	**545**	**190**	**591**	**315**	**1,641**	**—**	**50**	**50**	**1,691**
Production costs	**(1,070)**	**(46)**	**(375)**	**(232)**	**(1,723)**	**—**	**(223)**	**(223)**	**(1,946)**
Exploration costs	**(130)**	**(62)**	**(18)**	**(152)**	**(362)**	**—**	**(14)**	**(14)**	**(376)**
Depreciation, depletion and amortization	**(723)**	**(18)**	**(221)**	**(147)**	**(1,109)**	**—**	**(129)**	**(129)**	**(1,238)**
Other expenses	**(190)**	**(27)**	**(2)**	**(88)**	**(307)**	**—**	**(2)**	**(2)**	**(309)**
Results before estimated income taxes	**2,892**	**37**	**844**	**1,136**	**4,909**	**—**	**513**	**513**	**5,422**
Estimated income taxes	**(972)**	**(48)**	**(269)**	**(945)**	**(2,234)**	**—**	**(258)**	**(258)**	**(2,492)**
Net results	**$ 1,920**	**$ (11)**	**$ 575**	**$ 191**	**$ 2,675**	**$ —**	**$ 255**	**$ 255**	**$ 2,930**
For the year ended December 31, 1999									
Gross revenues from:									
Sales and transfers, including affiliate sales	$ 2,936	$ —	$ 617	$ 935	$ 4,488	$ —	$ 592	$ 592	$ 5,080
Sales to unaffiliated entities	230	116	498	202	1,046	—	24	24	1,070
Production costs	(943)	(39)	(435)	(252)	(1,669)	—	(205)	(205)	(1,874)
Exploration costs	(243)	(97)	(21)	(154)	(515)	—	(17)	(17)	(532)
Depreciation, depletion and amortization	(794)	(22)	(336)	(134)	(1,286)	—	(109)	(109)	(1,395)
Other expenses	(138)	(15)	(1)	(53)	(207)	—	(3)	(3)	(210)
Results before estimated income taxes	1,048	(57)	322	544	1,857	—	282	282	2,139
Estimated income taxes	(322)	(8)	(114)	(457)	(901)	—	(143)	(143)	(1,044)
Net results	$ 726	$ (65)	$ 208	$ 87	$ 956	$ —	$ 139	$ 139	$ 1,095
For the year ended December 31, 1998									
Gross revenues from:									
Sales and transfers, including affiliate sales	$ 2,570	$ —	$ 438	$ 571	$ 3,579	$ —	$ 454	$ 454	$ 4,033
Sales to unaffiliated entities	218	120	509	122	969	—	28	28	997
Production costs	(1,066)	(35)	(400)	(250)	(1,751)	—	(150)	(150)	(1,901)
Exploration costs	(286)	(31)	(53)	(137)	(507)	—	(16)	(16)	(523)
Depreciation, depletion and amortization	(832)	(22)	(422)	(113)	(1,389)	—	(106)	(106)	(1,495)
Other expenses	(198)	—	(4)	(10)	(212)	—	(1)	(1)	(213)
Results before estimated income taxes	406	32	68	183	689	—	209	209	898
Estimated income taxes	(49)	(14)	(27)	(166)	(256)	—	(102)	(102)	(358)
Net results	$ 357	$ 18	$ 41	$ 17	$ 433	$ —	$ 107	$ 107	$ 540

SUPPLEMENTAL MARKET RISK DISCLOSURES

We use derivative financial instruments to hedge interest rate, foreign currency exchange and commodity market risks. Derivatives principally include interest rate and/or currency swap contracts, forward and option contracts to buy and to sell foreign currencies, and commodity futures, options, swaps and other instruments. We hedge only a portion of our risk exposures for assets, liabilities, commitments and future production, purchases and sales. We remain exposed on the unhedged portion of such risks.

The estimated sensitivity effects below assume that valuations of all items within a risk category will move in tandem. This cannot be assured for exposures involving interest rates, currency exchange rates, petroleum and natural gas. Users should realize that actual impacts from future interest rate, currency exchange and petroleum and natural gas price movements will likely differ from the disclosed impacts due to ongoing changes in risk exposure levels and concurrent adjustments of hedging derivative positions. Additionally, the range of variability in prices and rates is representative only of past fluctuations for each risk category. Past fluctuations in rates and prices may not necessarily be an indicator of probable future fluctuations.

Notes 9, 14 and 15 to the financial statements include details of our hedging activities, fair values of financial instruments, related derivatives exposures and accounting policies.

DEBT AND DEBT-RELATED DERIVATIVES

We had variable rate debt of approximately \$2.4 billion and \$2.8 billion at year-end 2000 and 1999, before effects of related interest rate swaps. Interest rate swap notional amounts at year-end 2000 were virtually unchanged from year-end 1999.

Based on our overall interest rate exposure on variable rate debt and interest rate swaps at December 31, 2000 (including the interest rate and equity swap), a hypothetical two percentage point increase or decrease in interest rates would decrease or increase net income approximately \$50 million.

CURRENCY FORWARD EXCHANGE AND OPTION CONTRACTS

During 2000, the net notional amount of open forward contracts decreased \$710 million. This related to decreases in balance sheet monetary exposures and foreign currency capital projects.

The effect on fair value of our forward exchange contracts at year-end 2000 from a hypothetical 10% change in currency exchange rates would be an increase or decrease of approximately \$114 million. This would be offset by an opposite effect on the related hedged exposures.

PETROLEUM AND NATURAL GAS HEDGING

The notional amount of commodity derivatives outstanding at year-end 2000 that are permitted to be settled in cash or another financial instrument declined about 20% from year-end 1999. The aggregate effect of a hypothetical 20% change in natural gas prices, a 15% change in crude oil prices and a 20% change in petroleum product prices would not be material to our consolidated financial position, net income or cash flows.

INVESTMENTS IN DEBT AND PUBLICLY TRADED EQUITY SECURITIES

We are subject to price risk on this unhedged portfolio of available-for-sale securities. Our investments in available-for-sale securities were approximately the same at year-end 2000 and 1999. At year-end 2000, a 10% appreciation or depreciation in debt and equity prices would not have a material effect on consolidated financial position, net income or cash flows. This assumes no fluctuations in currency exchange rates.

PREFERRED SHARES OF SUBSIDIARIES

We are exposed to interest rate risk on dividend requirements of Series B preferred shares of Texaco Capital LLC.

We are exposed to currency exchange risk on the Canadian dollar denominated Series C preferred shares of Texaco Capital LLC. We are exposed to offsetting currency exchange risk as well as interest rate risk on a swap contract used to hedge the Series C.

Based on the above exposures, a hypothetical two percentage point increase or decrease in the applicable variable interest rates and a hypothetical 10% appreciation or depreciation in the Canadian dollar exchange rate would not materially affect our consolidated financial position, net income or cash flows.

MARKET AUCTION PREFERRED SHARES (MAPS)

We are exposed to interest rate risk on dividend requirements of MAPS. A hypothetical two percentage point increase or decrease in interest rates would not materially affect our consolidated financial position or cash flows. There are no derivatives related to MAPS.

SELECTED FINANCIAL DATA

Selected Quarterly Financial Data

(Millions of dollars)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
				2000				1999
Revenues								
Sales and services	**$ 11,086**	**$ 11,776**	**$ 13,027**	**$ 14,211**	$ 6,914	$ 8,116	$ 9,472	$ 10,473
Equity in income of affiliates, interest, asset sales and other	**185**	**293**	**332**	**220**	276	153	205	82
	11,271	**12,069**	**13,359**	**14,431**	7,190	8,269	9,677	10,555
Deductions								
Purchases and other costs	**8,630**	**9,425**	**10,251**	**11,270**	5,450	6,356	7,448	8,188
Operating expenses	**590**	**678**	**667**	**873**	559	550	544	666
Selling, general and administrative expenses	**325**	**256**	**323**	**387**	290	311	270	315
Exploratory expenses	**53**	**60**	**106**	**139**	130	80	72	219
Depreciation, depletion and amortization	**484**	**391**	**356**	**686**	361	365	356	461
Interest expense, taxes other than income taxes and minority interest	**252**	**230**	**236**	**244**	216	212	214	279
	10,334	**11,040**	**11,939**	**13,599**	7,006	7,874	8,904	10,128
Income before income taxes	**937**	**1,029**	**1,420**	**832**	184	395	773	427
Provision for (benefit from) income taxes	**363**	**404**	**622**	**287**	(15)	122	386	109
Net income	**$ 574**	**$ 625**	**$ 798**	**$ 545**	$ 199	$ 273	$ 387	$ 318
Comprehensive income	**$ 576**	**$ 620**	**$ 801**	**$ 534**	$ 179	$ 271	$ 393	$ 316
Net income per common share *(dollars)*								
Basic	**$ 1.05**	**$ 1.14**	**$ 1.47**	**$ 1.00**	$ .35	$ .50	$ .71	$ .58
Diluted	**$ 1.05**	**$ 1.14**	**$ 1.46**	**$ 1.00**	$ .35	$ .50	$ .71	$ .58

See accompanying notes to consolidated financial statements.

Five-Year Comparison of Selected Financial Data

(Millions of dollars)	**2000**	1999	1998	1997	1996
For the year:					
Revenues	**$ 51,130**	$ 35,691	$ 31,707	$ 46,667	$ 45,500
Net income before cumulative effect of accounting change	**$ 2,542**	$ 1,177	$ 603	$ 2,664	$ 2,018
Cumulative effect of accounting change	**—**	—	(25)	—	—
Net income	**$ 2,542**	$ 1,177	$ 578	$ 2,664	$ 2,018
Comprehensive income	**$ 2,531**	$ 1,159	$ 572	$ 2,601	$ 1,863
Net income per common share* *(dollars)*					
Basic					
Income before cumulative effect of accounting change	**$ 4.66**	$ 2.14	$ 1.04	$ 4.99	$ 3.77
Cumulative effect of accounting change	**—**	—	(.05)	—	—
Net income	**$ 4.66**	$ 2.14	$ .99	$ 4.99	$ 3.77
Diluted					
Income before cumulative effect of accounting change	**$ 4.65**	$ 2.14	$ 1.04	$ 4.87	$ 3.68
Cumulative effect of accounting change	**—**	—	(.05)	—	—
Net income	**$ 4.65**	$ 2.14	$ .99	$ 4.87	$ 3.68
Cash dividends per common share* *(dollars)*	**$ 1.80**	$ 1.80	$ 1.80	$ 1.75	$ 1.65
Total cash dividends paid on common stock	**$ 976**	$ 964	$ 952	$ 918	$ 859
At end of year:					
Total assets	**$ 30,867**	$ 28,972	$ 28,570	$ 29,600	$ 26,963
Debt and capital lease obligations					
Short-term	**$ 376**	$ 1,041	$ 939	$ 885	$ 465
Long-term	**6,815**	6,606	6,352	5,507	5,125
Total debt and capital lease obligations	**$ 7,191**	$ 7,647	$ 7,291	$ 6,392	$ 5,590

*Reflects two-for-one stock split effective September 29, 1997.

See accompanying notes to consolidated financial statements.