

Notes to Consolidated Financial Statements

NOTE 1 SEGMENT INFORMATION

We are presenting below information about our operating segments for the years 1999, 1998 and 1997, according to Statement of Financial Accounting Standards 131, "Disclosures about Segments of an Enterprise and Related Information," which we adopted in 1998. Due to the formation in 1999 of our Global Gas and Power segment, prior period information has been restated.

We determined our operating segments 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 1999

(Millions of dollars)	Sales and Services			After-tax Profit (Loss)	Income Tax Expense (Benefit)	DD&A Expense	Other Non-cash Items	Capital Expenditures	Assets at Year-End
	Outside	Inter-segment	Total						
Exploration and production									
United States	\$ 2,166	\$ 1,547	\$ 3,713	\$ 652	\$ 299	\$ 758	\$ 167	\$ 670	\$ 8,696
International	2,684	924	3,608	360	545	451	30	1,273	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	375	8,542
Global gas and power	4,422	117	4,539	(14)	(8)	65	10	161	1,297
Segment totals	<u>\$ 34,965</u>	<u>\$ 2,681</u>	<u>37,646</u>	<u>1,576</u>	<u>1,010</u>	<u>1,497</u>	<u>417</u>	<u>2,482</u>	<u>27,582</u>
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			<u>\$ 34,975</u>	<u>\$ 1,177</u>	<u>\$ 602</u>	<u>\$ 1,543</u>	<u>\$ 416</u>	<u>\$ 2,503</u>	<u>\$ 28,972</u>

Operating Segments 1998

(Millions of dollars)	Sales and Services			After-tax Profit (Loss)	Income Tax Expense (Benefit)	DD&A Expense	Other Non-cash Items	Capital Expenditures	Assets at Year-End
	Outside	Inter-segment	Total						
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 and power	4,748	76	4,824	(16)	4	15	45	122	1,119
Segment totals	<u>\$ 30,897</u>	<u>\$ 2,565</u>	<u>33,462</u>	<u>967</u>	<u>388</u>	<u>1,653</u>	<u>429</u>	<u>2,620</u>	<u>26,443</u>
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			<u>\$ 30,910</u>	<u>\$ 603</u>	<u>\$ 98</u>	<u>\$ 1,675</u>	<u>\$ 365</u>	<u>\$ 2,650</u>	<u>\$ 28,570</u>

Operating Segments 1997

(Millions of dollars)	Sales and Services			After-tax Profit (Loss)	Income Tax Expense (Benefit)	DD&A Expense	Other Non-cash Items	Capital Expenditures	Assets at Year-End
	Outside	Inter-segment	Total						
Exploration and production									
United States	\$ 365	\$ 4,149	\$ 4,514	\$ 990	\$ 487	\$ 783	\$ 281	\$ 1,349	\$ 8,769
International	2,565	693	3,258	812	566	442	104	901	4,107
Refining, marketing and distribution									
United States	16,984	250	17,234	325	172	178	169	262	5,668
International	20,009	362	20,371	508	117	173	(166)	482	7,908
Global gas and power	5,260	247	5,507	(46)	(6)	15	63	113	1,178
Segment totals	<u>\$ 45,183</u>	<u>\$ 5,701</u>	50,884	2,589	1,336	1,591	451	3,107	27,630
Other business units			64	2	2	1	3	—	431
Corporate/Non-operating			4	73	(675)	41	242	52	2,030
Intersegment eliminations			(5,765)	—	—	—	—	—	(491)
Consolidated			<u>\$ 45,187</u>	<u>\$ 2,664</u>	<u>\$ 663</u>	<u>\$ 1,633</u>	<u>\$ 696</u>	<u>\$ 3,159</u>	<u>\$ 29,600</u>

Our exploration and production segments explore for, find, develop and produce crude oil and natural gas. The United States segment in 1998 and 1997 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 and power 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 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 — *Investments and Advances*, beginning on page 41, 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 producing operations where the host governments own the physical assets under terms of the operating agreements.

(Millions of dollars)	Sales and Services			Long-lived assets at December 31		
	1999	1998	1997	1999	1998	1997
United States	\$ 9,733	\$ 8,184	\$ 21,657	\$ 8,630	\$ 8,757	\$ 11,437
International – Total	\$ 25,242	\$ 22,726	\$ 23,530	\$ 7,109	\$ 6,250	\$ 5,876
Significant countries included above:						
Brazil	2,404	3,175	3,175	326	301	266
Netherlands	1,955	1,636	1,901	246	257	250
United Kingdom	9,211	7,529	6,862	2,275	2,257	2,384

NOTE 2 ADOPTION OF NEW ACCOUNTING STANDARDS

SFAS 128 — During 1997, we adopted SFAS 128, “Earnings per Share.” Our basic and diluted net income per common share under SFAS 128 were approximately the same as under the comparable prior basis of reporting.

SFAS 130, 131 and 132 — In 1998, Texaco adopted SFAS 130, 131 and 132. SFAS 130, “Reporting Comprehensive Income,” requires that we report all items classified as comprehensive income under its provisions as separate components within a financial statement. SFAS 131, “Disclosures about Segments of an Enterprise and Related Information,” requires the reporting of certain income, revenue, expense and asset data about operating segments of public enterprises. Operating segments are based upon a company’s internal management structure. SFAS 131 also requires data for revenues and long-lived assets by major countries of operation. SFAS 132, “Employer’s Disclosures about Pensions and Other Postretirement Benefits,” requires disclosure of new information on changes in plan benefit obligations and fair values of plan assets.

SOP 98-5 — 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.

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.

	1999			1998			1997		
	Income	Shares	Per Share	Income	Shares	Per Share	Income	Shares	Per Share
<i>(Millions, except per share amounts)</i>									
<i>For the years ended December 31</i>									
Basic net income:									
Income before cumulative effect of accounting change	\$ 1,177			\$ 603			\$ 2,664		
Less: Preferred stock dividends	(29)			(54)			(56)		
Income before cumulative effect of accounting change, for basic income per share	\$ 1,148	535.4	\$ 2.14	\$ 549	528.4	\$ 1.04	\$ 2,608	522.2	\$ 4.99
Effect of dilutive securities:									
ESOP Convertible preferred stock	—	—		—	—		34	19.3	
Stock options and restricted stock	3	2.5		—	.4		—	.8	
Convertible debentures	—	—		1	.2		—	.3	
Income before cumulative effect of accounting change, for diluted income per share	\$ 1,151	537.9	\$ 2.14	\$ 550	529.0	\$ 1.04	\$ 2,642	542.6	\$ 4.87

NOTE 4 INVENTORIES

(Millions of dollars)
As of December 31

	1999	1998
Crude oil	\$ 141	\$ 116
Petroleum products and other	857	839
Materials and supplies	184	199
Total	\$ 1,182	\$ 1,154

At December 31, 1999, the excess of estimated market value over the carrying value of inventories was \$136 million. The carrying value of inventories at December 31, 1998 is net of a valuation allowance of \$99 million to adjust from cost to market value. This valuation allowance was reversed in 1999 as market prices increased and the associated physical units of inventory were sold.

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

	1999	1998
Affiliates accounted for on the equity method		
Exploration and production		
United States	\$ 243	\$ 230
International		
CPI	454	452
Other	14	24
	711	706
Refining, marketing and distribution		
United States		
Equilon	1,953	2,266
Motiva	686	896
International		
Caltex	1,685	1,747
Other	234	210
	4,558	5,119
Global gas and power	281	188
Other affiliates	13	3
Total	5,563	6,016
Miscellaneous investments, long-term receivables, etc., accounted for at:		
Fair value	138	470
Cost, less reserve	725	698
Total	\$ 6,426	\$ 7,184

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

	1999	1998	1997
Equity in net income (loss)			
Exploration and production			
United States	\$ 53	\$ 37	\$ 40
International			
CPI	139	107	171
Other	—	(12)	—
	192	132	211
Refining, marketing and distribution			
United States			
Equilon	142	199	—
Motiva	(3)	22	—
Star	—	(3)	95
Other	—	—	48
International			
Caltex	11	(36)	252
Other	27	15	20
	177	197	415
Global gas and power	6	(11)	(11)
Other affiliates	—	—	1
Total	\$ 375	\$ 318	\$ 616
Dividends received	\$ 716	\$ 709	\$ 332

The undistributed earnings of these affiliates included in our retained earnings were \$2,613 million, \$2,846 million and \$3,096 million as of December 31, 1999, 1998 and 1997.

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 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 eastern and Gulf Coast U.S. refining and marketing businesses. Texaco's and Saudi Aramco's interest 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. Texaco and Saudi Refining, Inc., each owns 32.5% and Shell owns 35% of Motiva.

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.

Motiva's and Star's assets at the respective balance sheet dates include the remaining portion of the assets which were originally transferred from Texaco to Star at the fair market value on the date of formation of Star. Our investment and equity in the income of Motiva and Star, as reported in our consolidated financial statements, reflect the remaining unamortized historical carrying cost of the assets transferred to Star at formation of Star. Additionally, our investments in Motiva and Star include adjustments for contractual arrangements on the formation of Star, principally involving contributed inventories.

<i>(Millions of dollars)</i>	Equilon	Motiva	Caltex Group	Other Affiliates	Total Texaco's Share
1999					
Gross revenues	\$ 29,398	\$ 12,196	\$ 14,915	\$ 2,895	\$ 25,650
Income (loss) before income taxes	\$ 347	\$ (69)	\$ 780	\$ 348	\$ 679
Net income (loss)	\$ 226	\$ (45)	\$ 390	\$ 232	\$ 375
As of December 31:					
Current assets	\$ 4,209	\$ 1,271	\$ 2,705	\$ 801	\$ 3,796
Non-current assets	7,208	5,307	7,604	2,230	9,321
Current liabilities	(5,636)	(1,278)	(3,395)	(736)	(4,916)
Non-current liabilities	(735)	(2,095)	(2,639)	(792)	(2,638)
Net equity	\$ 5,046	\$ 3,205	\$ 4,275	\$ 1,503	\$ 5,563

<i>(Millions of dollars)</i>	Equilon	Motiva	Star	Caltex Group	Other Affiliates	Total Texaco's Share
1998						
Gross revenues	\$ 22,246	\$ 5,371	\$ 3,190	\$ 11,505	\$ 2,541	\$ 20,021
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

<i>(Millions of dollars)</i>	Star	Caltex Group	Other Affiliates	Total Texaco's Share
1997				
Gross revenues	\$ 7,758	\$ 15,699	\$ 4,028	\$ 13,312
Income before income taxes	\$ 301	\$ 1,210	\$ 605	\$ 940
Net income	\$ 196	\$ 846	\$ 400	\$ 616
As of December 31:				
Current assets	\$ 1,042	\$ 2,521	\$ 947	\$ 1,965
Non-current assets	3,260	7,193	3,607	6,324
Current liabilities	(769)	(2,991)	(1,032)	(2,270)
Non-current liabilities	(1,072)	(2,131)	(2,022)	(2,198)
Net equity	\$ 2,461	\$ 4,592	\$ 1,500	\$ 3,821

NOTE 6 PROPERTIES, PLANT AND EQUIPMENT

<i>(Millions of dollars) As of December 31</i>	Gross		Net	
	1999	1998	1999	1998
Exploration and production				
United States	\$ 21,565	\$ 21,991	\$ 7,822	\$ 7,945
International	8,835	7,554	3,804	2,950
Total	30,400	29,545	11,626	10,895
Refining, marketing and distribution				
United States	33	75	22	27
International	4,575	4,487	3,107	3,055
Total	4,608	4,562	3,129	3,082
Global gas and power	748	660	317	267
Other	771	727	488	517
Total	\$ 36,527	\$ 35,494	\$ 15,560	\$ 14,761
Capital lease amounts included above	\$ 152	\$ 264	\$ 3	\$ 79

Accumulated depreciation, depletion and amortization totaled \$20,967 million and \$20,733 million at December 31, 1999 and 1998. Interest capitalized as part of properties, plant and equipment was \$28 million in 1999, \$21 million in 1998 and \$20 million in 1997.

In 1999, 1998 and 1997, we recorded pre-tax charges of \$87 million, \$150 million and \$63 million for the write-downs of impaired assets. These charges were recorded to depreciation, depletion and amortization expense.

1999

In our global gas and power 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.

1997

In our U.S. exploration and producing operating segment, pre-tax asset write-downs for impaired properties in Louisiana and Canada were \$48 million. The Louisiana impairment resulted from the write-downs of gas plants due to insufficient contract volumes and the Canadian impairment resulted from unsuccessful enhanced recovery projects and downward revisions to underground reserves.

In our international exploration and producing operating segment, pre-tax asset write-downs of \$15 million for impaired properties in the U.K. North Sea were caused by downward revisions to underground reserves.

Fair values were based on expected future discounted cash flows.

NOTE 7 FOREIGN CURRENCY

Currency translations resulted in pre-tax losses of \$47 million in 1999, \$80 million in 1998 and \$59 million in 1997. After applicable taxes, 1999 included a gain of \$25 million compared to a loss of \$94 million in 1998 and a gain of \$154 million in 1997.

The after-tax currency gain in 1999 related principally to balance sheet translation. After-tax currency impacts for years 1998 and 1997 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. In contrast, those currencies weakened against the U.S. dollar in 1997, which resulted in significant currency-related gains.

Results for 1997 through 1999 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 \$8 million in 1999, losses of \$5 million in 1998 and gains of \$28 million in 1997.

Effective October 1, 1997, Caltex changed the functional currency for its operations in its Korean and Japanese affiliates to the U.S. dollar.

Currency translation adjustments shown in the separate stockholders' equity account result from translation items pertaining to certain affiliates of Caltex. For 1999, we recorded unrealized losses of \$9 million from these adjustments. 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 years 1998 and 1997, currency translation losses recorded to stockholders' equity were \$2 million and \$40 million.

NOTE 8 TAXES

<i>(Millions of dollars)</i>	1999	1998	1997
Federal and other income taxes			
Current			
U.S. Federal	\$ 100	\$ (45)	\$ (538)
Foreign	678	283	689
State and local	(36)	12	61
Total	742	250	212
Deferred			
U.S.	(120)	(104)	457
Foreign	(20)	(48)	(6)
Total	(140)	(152)	451
Total income taxes	602	98	663
Taxes other than income taxes			
Oil and gas production	64	70	127
Property	69	108	139
Payroll	91	119	125
Other	110	126	129
Total	334	423	520
Import duties and other levies			
U.S.	34	36	53
Foreign	6,937	6,843	5,414
Total	6,971	6,879	5,467
Total direct taxes	7,907	7,400	6,650
Taxes collected from consumers	2,097	2,148	3,370
Total all taxes	\$ 10,004	\$ 9,548	\$ 10,020

The deferred income tax assets and liabilities included in the Consolidated Balance Sheet as of December 31, 1999 and 1998 amounted to \$198 million and \$205 million, as net current assets and \$1,468 million and \$1,644 million, as net non-current liabilities. The table that follows shows deferred income tax assets and liabilities by category:

<i>(Millions of dollars) As of December 31</i>	(Liability) Asset	
	1999	1998
Depreciation	\$ (991)	\$ (1,079)
Depletion	(383)	(429)
Intangible drilling costs	(881)	(726)
Other deferred tax liabilities	(691)	(686)
Total	(2,946)	(2,920)
Employee benefit plans	548	532
Tax loss carryforwards	599	641
Tax credit carryforwards	495	368
Environmental liabilities	123	116
Other deferred tax assets	711	639
Total	2,476	2,296
Total before valuation allowance	(470)	(624)
Valuation allowance	(800)	(815)
Total	\$ (1,270)	\$ (1,439)

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:

	1999	1998	1997
U.S. Federal income tax rate assumed to be applicable	35.0%	35.0%	35.0%
IRS settlement	—	—	(14.7)
Net earnings and dividends attributable to affiliated corporations accounted for on the equity method	(3.8)	(7.0)	(4.7)
Aggregate earnings and losses from international operations	14.4	10.4	6.2
U.S. tax adjustments	(5.0)	(8.7)	(.3)
Sales of stock of subsidiaries	(2.2)	(6.1)	—
Energy credits	(3.8)	(11.7)	(1.4)
Other	(.8)	2.1	(.2)
Effective income tax rate	33.8%	14.0%	19.9%

The year 1997 included a \$488 million benefit resulting from an IRS settlement.

For companies operating in the United States, pre-tax earnings before the cumulative effect of an accounting change aggregated \$484 million in 1999, \$194 million in 1998 and \$1,527 million in 1997. For companies with operations located outside the United States, pre-tax earnings on that basis aggregated \$1,295 million in 1999, \$507 million in 1998 and \$1,800 million in 1997.

Income taxes paid, net of refunds, amounted to \$600 million, \$430 million and \$285 million in 1999, 1998 and 1997.

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, 1999, amounted to \$1,708 million and \$2,187 million. The corresponding amounts at December 31, 1998 were \$1,328 million and \$2,226 million. Determination of the unrecognized U.S. deferred income taxes on these amounts is not practicable.

For the years 1999, 1998 and 1997, no loss carryforward benefits were recorded for U.S. Federal income taxes. For the years 1999, 1998 and 1997, the tax benefits recorded for loss carryforwards were \$54 million, \$30 million and \$31 million in foreign income taxes.

At December 31, 1999, we had worldwide tax basis loss carryforwards of approximately \$1,647 million, including \$941 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 \$245 million at December 31, 1999, expiring at various dates through 2004. Alternative minimum tax and other tax credit carryforwards available for U.S. Federal income tax purposes were \$461 million at December 31, 1999, of which \$357 million have no expiration date. The remaining credits expire at various dates through 2014. The credits that are not utilized by the expiration dates may be taken as deductions for U.S. Federal income tax purposes. For the year 1999, we recorded tax credit carryforwards of \$68 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	1999	1998
Notes payable to banks and others with originating terms of one year or less	\$ 1,251	\$ 368
Commercial paper	1,099	1,617
Current portion of long-term debt and capital lease obligations		
Indebtedness	734	991
Capital lease obligations	7	13
	3,091	2,989
Less short-term obligations intended to be refinanced	2,050	2,050
Total	\$ 1,041	\$ 939

The weighted average interest rate of commercial paper and notes payable to banks at December 31, 1999 and 1998 was 5.9%.

Long-term Debt and Capital Lease Obligations

<i>(Millions of dollars) As of December 31</i>	1999	1998
Long-Term Debt		
3-1/2% convertible notes due 2004	\$ 203	\$ 204
5.5% note due 2009	397	—
5.7% notes due 2008	201	201
6% notes due 2005	299	299
6-7/8% notes due 1999	—	200
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	147
8-1/4% debentures due 2006	150	150
8-3/8% debentures due 2022	198	198
8-1/2% notes due 2003	200	199
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% notes due 1999	—	200
9-3/4% debentures due 2020	250	250
Medium-term notes, maturing from 2000 to 2043 (7.0%)	757	543
Revolving Credit Facility, due 1999-2002 – variable rate (5.9%)	—	309
Pollution Control Revenue Bonds, due 2012 – variable rate (3.5%)	166	166
Other long-term debt:		
Texaco Inc. – Guarantee of ESOP Series F loan – variable rate (6.6%)	—	2
U.S. dollars (6.6%)	369	335
Other currencies (9.4%)	472	394
Total	5,251	5,238
Capital Lease Obligations (see Note 10)	46	68
	5,297	5,306
Less current portion of long-term debt and capital lease obligations	741	1,004
	4,556	4,302
Short-term obligations intended to be refinanced	2,050	2,050
Total long-term debt and capital lease obligations	\$ 6,606	\$ 6,352

The percentages shown for variable-rate debt are the interest rates at December 31, 1999. The percentages shown for the categories “Medium-term notes” and “Other long-term debt” are the weighted average interest rates at year-end 1999. Where applicable, principal amounts shown in the preceding schedule include unamortized premium or discount. Interest paid, net of amounts capitalized, amounted to \$480 million in 1999, \$474 million in 1998 and \$395 million in 1997.

At December 31, 1999, we had revolving credit facilities with commitments of \$2.05 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 1999. 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.

At December 31, 1999, our long-term debt included \$2.05 billion of short-term obligations scheduled to mature during 2000, which we have both the intent and the ability to refinance on a long-term basis through the use of our \$2.05 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, 1999 are as follows (in millions):

2000	2001	2002	2003	2004
\$ 734	\$ 135	\$ 191	\$ 273	\$ 31

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 the lower cost of floating rate debt, with its inherent increased risk, with fixed rate debt having less market risk. To achieve this objective, we also use off-balance sheet derivative instruments, primarily interest rate swaps, to manage identifiable exposures on a non-leveraged, non-speculative basis.

Summarized below are the carrying amounts and fair values of our debt and debt-related derivatives at December 31, 1999 and 1998. 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.

<i>(Millions of dollars) As of December 31</i>	1999	1998
Notes Payable and Commercial Paper:		
Carrying amount	\$ 2,350	\$ 1,985
Fair value	2,348	1,985
<i>Related Derivatives – Payable (Receivable):</i>		
Carrying amount	\$ —	\$ —
Fair value	(13)	17
Notional principal amount	\$ 300	\$ 300
Weighted average maturity <i>(years)</i>	7.3	8.3
Weighted average fixed pay rate	6.42%	6.42%
Weighted average floating receive rate	6.42%	5.32%
Long-Term Debt, including current maturities:		
Carrying amount	\$ 5,251	\$ 5,238
Fair value	5,225	5,842
<i>Related Derivatives – Payable (Receivable):</i>		
Carrying amount	\$ (19)	\$ (4)
Fair value	55	(9)
Notional principal amount	\$ 1,294	\$ 449
Weighted average maturity <i>(years)</i>	5.8	8.4
Weighted average fixed receive rate	5.69%	6.24%
Weighted average floating pay rate	6.10%	5.03%
Unamortized net gain on terminated swaps		
Carrying amount	\$ 4	\$ 5

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. Also, 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 1999 and 1998.

During 1999, floating rate pay swaps having an aggregate notional principal amount of \$30 million were amortized or matured. We initiated \$875 million of new floating rate pay swaps in connection with certain of the 1999 debt issuances. There was no activity in fixed rate pay swaps during 1999.

Fair values of debt are based upon quoted market prices, as well as 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, 1999, 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:

<i>(Millions of dollars)</i>	Operating Leases	Capital Leases
2000	\$ 134	\$ 9
2001	93	9
2002	416	8
2003	50	7
2004	54	7
After 2004	315	14
Total lease commitments	\$ 1,062	\$ 54
Less interest		8
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.

<i>(Millions of dollars)</i>	1999	1998	1997
Rental expense			
Minimum lease rentals	\$ 218	\$ 208	\$ 270
Contingent rentals	6	—	3
Total	224	208	273
Less rental income on properties subleased to others			
	54	50	78
Net rental expense	\$ 170	\$ 158	\$ 195

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)

We recorded ESOP expense of \$3 million in 1999, \$1 million in 1998 and \$2 million in 1997. Our contributions to the Employees Thrift Plan of Texaco Inc. and the Employees Savings Plan of Texaco Inc. amounted to \$3 million in 1999, \$1 million in 1998 and \$2 million in 1997. These plans are 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 1999, we made a \$27 million advanced company ESOP allocation for the period December 1999 through November 2000 to participants of the Employees Thrift Plan.

During the year, we called the Series B and Series F Convertible Preferred Stock and converted them into Texaco common stock, with future ESOP allocations being made in common stock. Following this conversion, we paid \$12 million in dividends. Dividends on the preferred and common ESOP shares used to service debt of the plans are tax deductible to the company.

In 1999, 1998 and 1997, we paid \$19 million, \$42 million and \$44 million in dividends on Series B and Series F stock. The trustee applied the dividends to fund interest payments which amounted to \$2 million, \$5 million and \$7 million for 1999, 1998 and 1997, as well as to reduce principal on the ESOP loans. The Savings Plan ESOP loan was satisfied in January 1999. In November 1998 and December 1997, a portion of the original Thrift Plan ESOP loan was refinanced through a company loan. The refinancing will extend the ESOP for a period of up to six years.

We include in our long-term debt the plans' original ESOP loans guaranteed by Texaco Inc. As the ESOP repays the original and refinanced ESOP loans, we reduce the remaining ESOP-related unearned employee compensation included as a component of stockholders' equity.

Benefit Plan Trust

We have established a benefit plan trust for funding company obligations under some of our benefit plans. At year-end 1999, 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 and power 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 1,100 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. The restructuring programs were completed during 1999. Through December 31, 1999, under these programs we have separated 2,462 employees and paid \$124 million of benefits and transferred \$12 million to long-term obligations. The remaining benefits of \$27 million will be paid in future periods in accordance with plan provisions.

We recorded an after-tax charge of \$56 million in the fourth quarter of 1996 to cover the costs of employee separations, including employees of affiliates, as a result of a company-wide realignment and consolidation of our operations. We recorded an adjustment of \$6 million in the fourth quarter of 1997 to increase the accrual from the previous amount. The program was completed by the end of 1997 with the reduction of approximately 920 employees. During 1999 we paid \$4 million of benefits under this program. The remaining benefits of \$8 million will be paid 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 and final average pay. Pension plan assets are principally invested in equity and fixed income securities and deposits with insurance companies.

Effective October 1, 1999, the Retirement Plan was changed to provide improved early retirement benefits and/or lump sum options availability, for vested employees who terminate before age 55. Pensions are now based on a new point system (age plus service) which pays graduated pensions to terminating members.

Total worldwide expense for all employee pension plans of Texaco, including pension supplementations and smaller non-U.S.

plans, was \$41 million in 1999 and \$92 million in 1998 and 1997.

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

	Pension Benefits				Other U.S. Benefits	
	1999		1998		1999	1998
(Millions of dollars) As of December 31	U.S.	Int'l	U.S.	Int'l	1999	1998
Changes in Benefit (Obligations)						
Benefit (obligations) at January 1	\$ (1,884)	\$ (979)	\$ (1,769)	\$ (835)	\$ (773)	\$ (756)
Service cost	(46)	(25)	(60)	(21)	(6)	(9)
Interest cost	(113)	(82)	(117)	(86)	(49)	(50)
Amendments	(29)	(23)	—	(3)	12	—
Actuarial gain/(loss)	(16)	(26)	(191)	(117)	59	8
Employee contributions	(3)	(1)	(4)	(3)	(14)	(12)
Benefits paid	63	62	64	70	66	56
Curtailments/settlements	364	(2)	193	—	12	(7)
Special termination benefits	—	—	(12)	—	—	(3)
Currency adjustments	—	96	—	16	—	—
Acquisitions/joint ventures	—	—	12	—	60	—
Benefit (obligations) at December 31	\$ (1,664)	\$ (980)	\$ (1,884)	\$ (979)	\$ (633)	\$ (773)
Changes in Plan Assets						
Fair value of plan assets at January 1	\$ 1,826	\$ 1,028	\$ 1,702	\$ 900	\$ —	\$ —
Actual return on plan assets	236	151	293	142	—	—
Company contributions	15	26	90	32	52	44
Employee contributions	3	1	4	3	14	12
Expenses	(7)	—	(6)	(2)	—	—
Benefits paid	(63)	(62)	(64)	(70)	(66)	(56)
Currency adjustments	—	(74)	—	23	—	—
Curtailments/settlements	(364)	—	(176)	—	—	—
Acquisitions/joint ventures	—	—	(17)	—	—	—
Fair value of plan assets at December 31	\$ 1,646	\$ 1,070	\$ 1,826	\$ 1,028	\$ —	\$ —
Funded Status of the Plans						
Obligation (greater than) less than assets	\$ (18)	\$ 90	\$ (58)	\$ 49	\$ (633)	\$ (773)
Unrecognized net transition asset	(7)	(1)	(14)	(14)	—	—
Unrecognized prior service cost	85	63	68	52	(7)	4
Unrecognized actuarial (gain)/loss	(161)	(17)	(93)	4	(143)	(92)
Net (liability)/asset recorded in Texaco's Consolidated Balance Sheet	\$ (101)	\$ 135	\$ (97)	\$ 91	\$ (783)	\$ (861)
Net (liability)/asset recorded in Texaco's Consolidated Balance Sheet consists of:						
Prepaid benefit asset	\$ 84	\$ 373	\$ 72	\$ 346	\$ —	\$ —
Accrued benefit liability	(231)	(246)	(215)	(268)	(783)	(861)
Intangible asset	23	8	23	12	—	—
Other accumulated non-owner equity	23	—	23	1	—	—
Net (liability)/asset recorded in Texaco's Consolidated Balance Sheet	\$ (101)	\$ 135	\$ (97)	\$ 91	\$ (783)	\$ (861)
Assumptions as of December 31						
Discount rate	8.0%	8.1%	6.75%	9.5%	8.0%	6.75%
Expected return on plan assets	10.0%	8.8%	10.0%	8.4%	—	—
Rate of compensation increase	4.0%	5.2%	4.0%	6.1%	4.0%	4.0%
Health care cost trend rate	—	—	—	—	4.0%	4.0%

<i>(Millions of dollars) As of December 31</i>	Pension Benefits						Other U.S. Benefits		
	1999		1998		1997		1999	1998	1997
	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l			
Components of Net Periodic Benefit Expenses									
Service cost	\$ 46	\$ 25	\$ 60	\$ 21	\$ 54	\$ 17	\$ 6	\$ 9	\$ 6
Interest cost	113	82	117	86	117	85	49	50	49
Expected return on plan assets	(140)	(81)	(136)	(79)	(132)	(66)	—	—	—
Amortization of transition asset	(6)	(12)	(4)	(10)	(5)	(8)	—	—	—
Amortization of prior service cost	11	13	11	7	10	6	—	—	—
Amortization of (gain)/loss	4	(2)	6	(2)	3	—	(1)	(4)	(5)
Curtailments/settlements	(15)	2	6	—	—	—	(12)	1	—
Special termination charges	—	—	8	—	—	—	—	2	—
Net periodic benefit expenses	\$ 13	\$ 27	\$ 68	\$ 23	\$ 47	\$ 34	\$ 42	\$ 58	\$ 50

For pension plans with accumulated obligations in excess of plan assets, the projected benefit obligation and the accumulated benefit obligation were \$410 million and \$379 million as of December 31, 1999, and \$414 million and \$383 million as of December 31, 1998. The fair value of plan assets for both years was \$0.

In connection with the formation of Equilon, effective January 1, 1998, we transferred to Equilon pension benefit obligations of \$12 million and related plan assets of \$17 million.

Other U.S. Benefits

We sponsor postretirement plans in the U.S. that provide health care and life insurance for retirees and eligible dependents. Effective October 1, 1999, we introduced 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.

As a result of the transfer of employees to the downstream alliances effective April 1, 1999, \$58 million of postretirement benefit obligations were also transferred.

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:

<i>(Millions of dollars)</i>	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	\$ 38	\$ (34)

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, 1999, 1998 and 1997 available for awards during the subsequent year:

<i>(Shares) As of December 31</i>	1999	1998	1997
To all participants	15,646,336	12,677,325	9,607,506
To those participants not officers or directors	2,020,621	1,967,715	2,362,273
Total	17,666,957	14,645,040	11,969,779

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:

	1999	1998	1997
Shares	278,402	334,798	281,174
Weighted average fair value	\$ 62.78	\$ 61.59	\$ 55.09

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 \$19 million in 1999, \$17 million in 1998 and \$18 million in 1997. 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:

	1999	1998	1997
Net income (<i>Millions of dollars</i>)			
As reported	\$ 1,177	\$ 578	\$ 2,664
Pro forma	\$ 1,107	\$ 524	\$ 2,621
Earnings per share (<i>dollars</i>)			
Basic — as reported	\$ 2.14	\$.99	\$ 4.99
— pro forma	\$ 2.01	\$.89	\$ 4.91
Diluted — as reported	\$ 2.14	\$.99	\$ 4.87
— pro forma	\$ 2.01	\$.89	\$ 4.79

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

	1999	1998	1997
Expected life	2 yrs.	2 yrs.	2 yrs.
Interest rate	5.4%	5.4%	6.0%
Volatility	29.1%	22.5%	18.6%
Dividend yield	3.0%	3.0%	3.0%

Option award activity during 1999, 1998 and 1997 is summarized in the following table:

	1999		1998		1997	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
(<i>Stock options</i>)						
Outstanding January 1	11,616,049	\$ 59.48	10,071,307	\$ 53.31	9,436,406	\$ 42.73
Granted	2,015,741	62.78	2,388,593	61.56	2,084,902	55.06
Exercised	(8,163,386)	59.24	(7,732,978)	53.18	(9,533,861)	44.86
Restored	7,448,018	64.55	6,889,941	60.77	8,103,502	55.32
Canceled	(819,284)	64.48	(814)	78.08	(19,642)	51.43
Outstanding December 31	12,097,138	62.98	11,616,049	59.48	10,071,307	53.31
Exercisable December 31	6,358,652	\$ 62.57	5,945,445	\$ 58.93	3,197,262	\$ 51.21
Weighted average fair value of options granted during the year		\$ 11.21		\$ 8.48		\$ 6.92

The following table summarizes information on stock options outstanding at December 31, 1999:

Exercisable Price Range (per share)	Options Outstanding			Options Exercisable	
	Shares	Weighted Average Remaining Life	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
\$ 25.36 – 31.84	20,323	2.4 yrs.	\$ 29.32	20,323	\$ 29.32
\$ 32.47 – 78.08	12,076,815	6.3 yrs.	\$ 63.04	6,338,329	\$ 62.67
\$ 25.36 – 78.08	12,097,138	6.3 yrs.	\$ 62.98	6,358,652	\$ 62.57

NOTE 13 PREFERRED STOCK AND RIGHTS**Series B ESOP Convertible Preferred Stock**

At December 31, 1998, the outstanding shares of Series B ESOP Convertible Preferred Stock (Series B) were held by an ESOP. Dividends on each share of Series B were cumulative and payable semiannually at the rate of \$57 per annum.

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, 1999, the Rights are not exercisable.

Series F ESOP Convertible Preferred Stock

At December 31, 1998, the outstanding shares of Series F ESOP Convertible Preferred Stock (Series F) were held by an ESOP. Dividends on each share of Series F were cumulative and payable semiannually at the rate of \$64.53 per annum.

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 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). For 1997, the annual dividend rate for the MAPS ranged between 3.88% and 4.29% and dividends totaled \$11 million (\$9,689, \$9,650, \$9,675 and \$9,774 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 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 non-performance 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, 1999 and 1998 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, 1999 includes \$67 million of time deposits and \$165 million of commercial paper. Comparable amounts at year-end 1998 were \$72 million and \$109 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, 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. At December 31, 1998, our available-for-sale securities had an estimated fair value of \$492 million, including gross unrealized gains

of \$40 million and losses of \$8 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 \$750 million in 1999, \$1,011 million in 1998 and \$1,040 million in 1997. These sales resulted in gross realized gains of \$45 million in 1999, \$53 million in 1998 and \$48 million in 1997, and gross realized losses of \$13 million, \$22 million and \$19 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, 1999 and 1998 carrying values of \$465 million and \$331 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, 1999 and 1998.

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.

<i>(Millions of dollars)</i>	Buy	Sell
Australian dollars	\$ 251	\$ 37
British pounds	1,161	145
Danish kroner	245	39
Euro	264	40
New Zealand dollars	145	—
Other European currencies	56	11
Total at December 31, 1999	\$ 2,122	\$ 272
Total at December 31, 1998	\$ 2,953	\$ 883

Market risk exposure on these contracts is essentially limited to currency rate movements. At year-end 1999, there were \$10 million of unrealized gains and \$30 million of unrealized losses related to these contracts. At year-end 1998, there were \$8 million of unrealized gains and \$19 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 income currently as other costs. At year-end 1999 and 1998, 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 – 90% in 1999 and 54% in 1998; Danish kroner – 94% in 1999 and 40% in 1998. 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 1999 and 1998, net hedging gains of \$17 million and \$50 million, respectively, 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, 1999 and 1998, 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 \$6,604 million and \$4,397 million at year-end 1999 and 1998. 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 twelve months. Unrealized gains and losses on contracts outstanding at year-end 1999 were \$195 million and \$132 million, respectively. At year-end 1998, unrealized gains and losses were \$161 million and \$140 million, respectively.

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, 1999, the balance sheet includes liabilities of \$246 million for future environmental remediation costs. Also, we have accrued \$803 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 1999, 1998 and 1997.

Texaco Capital LLC, another subsidiary, 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 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 5.0% for 1999, 5.1% for 1998 and 5.9% for 1997. 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 1999, 1998 and 1997 totaled \$24 million for each year. Annual dividends on Series B totaled \$6 million for both 1999 and 1998 and \$7 million for 1997.

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 1999 and 1998, the carrying amounts of this swap, which approximated fair value, were \$20 million and \$16 million, respectively.

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.

The UNCC funds compensation awards by retaining 30% of Iraqi oil sales revenue under an agreement with Iraq. We do not know when we will receive this award since the timing of payments by the 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 \$716 million and \$797 million at December 31, 1999 and 1998. The year-end 1999 and 1998 amounts include \$336 million and \$387 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.

On December 22, 1999, our 50% owned affiliate, Caltex Corporation (Caltex), settled an excise tax claim with the United States Internal Revenue Service (IRS) for \$65 million. The IRS claim related to sales of crude oil by Caltex to Japanese customers beginning in 1980. The original claim was for \$292 million in excise taxes, \$140 million in penalties and \$1.6 billion in interest. In order to litigate this claim, Caltex had arranged for a letter of credit for \$2.5 billion. Pursuant to an agreement with the IRS in May 1999, the letter of credit was reduced to \$200 million. The letter of credit, which Texaco and its 50% partner, Chevron Corporation, had severally guaranteed, was terminated upon settlement. Resolution of this matter had no significant impact on reported results.

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, 1999 and 1998, our maximum exposure to loss was estimated to be \$445 million and \$500 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 \$173 million and \$195 million at December 31, 1999 and 1998.

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.

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:

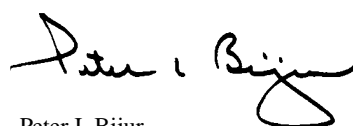
- > Corporate Conduct Guidelines requiring all employees to obey all applicable laws, comply with company policies and maintain the highest ethical standards in conducting company business,
- > An organizational structure in which responsibilities are defined and divided, and
- > Written policies and 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.

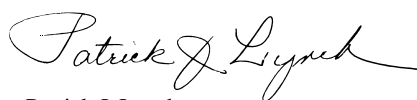
Texaco's internal auditors review and report on the effectiveness of internal controls during the course of their audits. Arthur Andersen LLP, selected by the Audit Committee and approved by stockholders, independently audits Texaco's financial statements. Arthur Andersen LLP assesses the adequacy and 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.

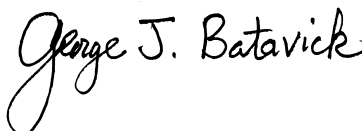
The Audit Committee is comprised of six directors who are not employees of Texaco. This Committee reviews and evaluates Texaco's accounting policies and reporting practices, internal auditing, internal controls, security and other matters. The Committee also evaluates the independence and professional 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.



Peter I. Bijur
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, 1999 and 1998, and the related statements of consolidated income, cash flows, stockholders' equity and non-owner changes in equity for each of the three years in the period ended December 31, 1999. 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, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999 in conformity with accounting principles generally accepted in the United States.



Arthur Andersen LLP
February 24, 2000
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 of Crude Oil and Natural Gas Liquids (Millions of Barrels)

Net Proved Reserves of Natural Gas (Billions of Cubic Feet)

	Consolidated Subsidiaries					Equity	World-wide	Consolidated Subsidiaries					Equity	World-wide
	United States	Other West	Europe	Other East	Total	Affiliate – Other East		United States	Other West	Europe	Other East	Total	Affiliate – Other East	
Developed reserves	1,100	50	165	418	1,733	354	2,087	3,360	893	452	96	4,801	136	4,937
Undeveloped reserves	222	6	232	48	508	109	617	368	138	509	4	1,019	17	1,036
As of December 31, 1996	1,322	56	397	466	2,241	463	2,704	3,728	1,031	961	100	5,820	153	5,973
Discoveries & extensions	107	13	34	61	215	4	219	692	26	92	346	1,156	2	1,158
Improved recovery	15	—	65	—	80	18	98	7	—	22	—	29	5	34
Revisions	55	3	11	100	169	22	191	228	75	41	(22)	322	19	341
Net purchases (sales)	413	(2)	(31)	(8)	372	—	372	10	(118)	(7)	(310)	(425)	—	(425)
Production	(145)	(5)	(45)	(66)	(261)	(56)	(317)	(643)	(96)	(81)	(2)	(822)	(17)	(839)
Total changes	445	9	34	87	575	(12)	563	294	(113)	67	12	260	9	269
Developed reserves	1,374	54	210	463	2,101	354	2,455	3,379	792	576	110	4,857	145	5,002
Undeveloped reserves	393	11	221	90	715	97	812	643	126	452	2	1,223	17	1,240
As of December 31, 1997*	1,767	65	431	553	2,816	451	3,267	4,022	918	1,028	112	6,080	162	6,242
Discoveries & extensions	70	2	8	32	112	1	113	599	6	47	98	750	1	751
Improved recovery	136	—	16	3	155	156	311	4	—	7	—	11	3	14
Revisions	46	(15)	22	55	108	137	245	152	(12)	(6)	34	168	10	178
Net purchases (sales)	(38)	—	—	26	(12)	—	(12)	(39)	—	—	250	211	—	211
Production	(157)	(4)	(58)	(71)	(290)	(61)	(351)	(633)	(92)	(112)	(17)	(854)	(25)	(879)
Total changes	57	(17)	(12)	45	73	233	306	83	(98)	(64)	365	286	(11)	275
Developed reserves	1,415	39	246	490	2,190	456	2,646	3,345	688	615	374	5,022	135	5,157
Undeveloped reserves	409	9	173	108	699	228	927	760	132	349	103	1,344	16	1,360
As of December 31, 1998*	1,824	48	419	598	2,889	684	3,573	4,105	820	964	477	6,366	151	6,517
Discoveries & extensions	66	11	23	23	123	2	125	442	7	93	42	584	5	589
Improved recovery	34	—	2	29	65	52	117	4	—	2	235	241	1	242
Revisions	11	—	36	72	119	(132)	(13)	285	193	7	427	912	3	915
Net purchases (sales)	(9)	—	—	23	14	—	14	(81)	—	—	712	631	—	631
Production	(144)	(4)	(53)	(75)	(276)	(60)	(336)	(550)	(79)	(104)	(27)	(760)	(26)	(786)
Total changes	(42)	7	8	72	45	(138)	(93)	100	121	(2)	1,389	1,608	(17)	1,591
Developed reserves	1,361	39	261	545	2,206	316	2,522	3,388	865	557	787	5,597	131	5,728
Undeveloped reserves	421	16	166	125	728	230	958	817	76	405	1,079	2,377	3	2,380
As of December 31, 1999*	1,782	55	427	670	2,934	546	3,480	4,205	941^(a)	962	1,866	7,974^(a)	134	8,108^(a)
*Includes net proved NGL reserves														
As of December 31, 1997	246	—	71	—	317	4	321							
As of December 31, 1998	250	—	68	22	340	6	346							
As of December 31, 1999	250	—	74	134	458	1	459							

(a) Additionally, there is approximately 489 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 1999	111%	99%	124%
Year 1998	166%	144%	191%
Year 1997	167%	132%	212%
3-year average	148%	126%	174%
5-year average	138%	115%	166%

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	Worldwide
	United States	Other West	Europe	Other East	Total	Affiliate – Other East	
<i>(Millions of dollars)</i>							
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	\$ 84,360
Future production costs	(10,956)	(913)	(2,264)	(2,946)	(17,079)	(2,254)	(19,333)
Future development costs	(3,853)	(239)	(1,749)	(1,956)	(7,797)	(767)	(8,564)
Future income tax expense	(8,304)	(758)	(2,428)	(7,665)	(19,155)	(2,340)	(21,495)
Net future cash flows before discount	22,168	758	5,434	4,323	32,683	2,285	34,968
10% discount for timing of future cash flows	(10,816)	(327)	(1,985)	(2,243)	(15,371)	(887)	(16,258)
Standardized measure of discounted future net cash flows	\$ 11,352	\$ 431	\$ 3,449	\$ 2,080	\$ 17,312	\$ 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	\$ 40,909
Future production costs	(10,465)	(605)	(2,574)	(2,551)	(16,195)	(1,992)	(18,187)
Future development costs	(4,055)	(142)	(1,695)	(761)	(6,653)	(803)	(7,456)
Future income tax expense	(2,583)	(419)	(715)	(1,023)	(4,740)	(967)	(5,707)
Net future cash flows before discount	6,044	491	1,597	481	8,613	946	9,559
10% discount for timing of future cash flows	(2,626)	(244)	(644)	(167)	(3,681)	(391)	(4,072)
Standardized measure of discounted future net cash flows	\$ 3,418	\$ 247	\$ 953	\$ 314	\$ 4,932	\$ 555	\$ 5,487
As of December 31, 1997							
Future cash inflows from sale of oil & gas, and service fee revenue	\$ 34,084	\$ 2,305	\$ 9,395	\$ 7,690	\$ 53,474	\$ 5,182	\$ 58,656
Future production costs	(10,980)	(807)	(2,854)	(2,303)	(16,944)	(1,840)	(18,784)
Future development costs	(4,693)	(132)	(1,809)	(749)	(7,383)	(476)	(7,859)
Future income tax expense	(5,512)	(652)	(898)	(3,445)	(10,507)	(1,519)	(12,026)
Net future cash flows before discount	12,899	714	3,834	1,193	18,640	1,347	19,987
10% discount for timing of future cash flows	(5,361)	(252)	(1,424)	(374)	(7,411)	(519)	(7,930)
Standardized measure of discounted future net cash flows	\$ 7,538	\$ 462	\$ 2,410	\$ 819	\$ 11,229	\$ 828	\$ 12,057

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

<i>(Millions of dollars)</i>	Worldwide Including Equity in Affiliate – Other East		
	1999	1998	1997
Standardized measure – beginning of year	\$ 5,487	\$ 12,057	\$ 17,966
Sales of minerals-in-place	(352)	(160)	(79)
	5,135	11,897	17,887
Changes in ongoing oil and gas operations:			
Sales and transfers of produced oil and gas, net of production costs during the period	(4,230)	(3,129)	(4,921)
Net changes in prices, production and development costs	21,990	(11,205)	(14,632)
Discoveries and extensions and improved recovery, less related costs	1,821	728	2,681
Development costs incurred during the period	1,598	1,770	1,976
Timing of production and other changes	(517)	(1,170)	(969)
Revisions of previous quantity estimates	301	852	1,476
Purchases of minerals-in-place	895	48	449
Accretion of discount	881	1,916	3,027
Net change in discounted future income taxes	(9,164)	3,780	5,083
Standardized measure – end of year	\$ 18,710	\$ 5,487	\$ 12,057

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 activities, geothermal 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	
	United States	Other West	Europe	Other East	Total	Affiliate – Other East	Worldwide
<i>(Millions of dollars)</i>							
As of December 31, 1999							
Proved properties	\$ 20,364	\$ 304	\$ 5,327	\$ 2,273	\$ 28,268	\$ 1,085	\$ 29,353
Unproved properties	983	139	50	619	1,791	335	2,126
Support equipment and facilities	441	267	37	529	1,274	975	2,249
Gross capitalized costs	21,788	710	5,414	3,421	31,333	2,395	33,728
Accumulated depreciation, depletion and amortization	(13,855)	(298)	(3,955)	(1,365)	(19,473)	(1,217)	(20,690)
Net capitalized costs	\$ 7,933	\$ 412	\$ 1,459	\$ 2,056	\$ 11,860	\$ 1,178	\$ 13,038
As of December 31, 1998							
Proved properties	\$ 20,601	\$ 515	\$ 4,709	\$ 1,799	\$ 27,624	\$ 1,015	\$ 28,639
Unproved properties	1,188	53	71	390	1,702	408	2,110
Support equipment and facilities	437	27	37	342	843	768	1,611
Gross capitalized costs	22,226	595	4,817	2,531	30,169	2,191	32,360
Accumulated depreciation, depletion and amortization	(14,140)	(277)	(3,381)	(1,253)	(19,051)	(1,119)	(20,170)
Net capitalized costs	\$ 8,086	\$ 318	\$ 1,436	\$ 1,278	\$ 11,118	\$ 1,072	\$ 12,190

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 1999 we spent \$4.37 for each BOE we added. Finding and development costs averaged \$3.80 for the three-year period 1997-1999 and \$3.88 per BOE for the five-year period 1995-1999.

Table V – Costs Incurred

(Millions of dollars)	Consolidated Subsidiaries					Equity	
	United States	Other West	Europe	Other East	Total	Affiliate – Other East	Worldwide
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	562
Development	698	97	319	301	1,415	183	1,598
Total	\$ 945	\$ 214	\$ 342	\$ 1,033	\$ 2,534	\$ 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	870
Development	1,073	25	308	204	1,610	160	1,770
Total	\$ 1,602	\$ 118	\$ 373	\$ 712	\$ 2,805	\$ 179	\$ 2,984
For the year ended December 31, 1997							
Proved property acquisition	\$ 1,099*	\$ —	\$ —	\$ —	\$ 1,099	\$ —	\$ 1,099
Unproved property acquisition	527*	1	—	23	551	—	551
Exploration	480	15	59	234	788	18	806
Development	1,220	62	419	108	1,809	167	1,976
Total	\$ 3,326	\$ 78	\$ 478	\$ 365	\$ 4,247	\$ 185	\$ 4,432

*Includes the acquisition of Monterey Resources on a net cost basis of \$1,520 million, which is net of deferred income taxes amounting to \$469 million and \$245 million for the acquired proved and unproved properties, respectively.

Table VI – Unit Prices

Average sales prices are calculated using the gross revenues in Table VII. Average production costs equal producing (lifting) costs,

other taxes and the depreciation, depletion and amortization of support equipment and facilities.

	Average sales prices						Average production costs (per composite barrel)		
	Crude oil and NGL per barrel	Natural gas per thousand cubic feet	Crude oil and NGL per barrel	Natural gas per thousand cubic feet	Crude oil and NGL per barrel	Natural gas per thousand cubic feet	1999	1998	1997
							1999	1998	1997
United States	\$ 16.56	\$ 2.13	\$ 10.14	\$ 1.93	\$ 16.32	\$ 2.32	\$ 4.01	\$ 4.07	\$ 3.94
Other West	14.12	.77	9.65	.92	14.40	1.03	2.87	1.86	2.80
Europe	17.42	1.99	11.73	2.42	18.41	2.42	6.15	5.24	5.58
Other East	15.33	.18	9.61	.38	16.87	1.89	3.45	3.65	4.11
Affiliate – Other East	13.24	—	9.81	—	14.89	—	3.95	2.68	3.76

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 activities, geothermal 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	
	United States	Other West	Europe	Other East	Total	Affiliate – Other East	Worldwide
<i>(Millions of dollars)</i>							
For the year ended December 31, 1999							
Gross revenues from:							
Sales and transfers, including affiliate sales	\$ 2,890	\$ —	\$ 617	\$ 935	\$ 4,442	\$ 592	\$ 5,034
Sales to unaffiliated entities	230	116	498	202	1,046	24	1,070
Production costs	(943)	(39)	(435)	(252)	(1,669)	(205)	(1,874)
Exploration costs	(243)	(97)	(21)	(154)	(515)	(17)	(532)
Depreciation, depletion and amortization	(794)	(22)	(336)	(134)	(1,286)	(109)	(1,395)
Other expenses	(92)	(15)	(1)	(53)	(161)	(3)	(164)
Results before estimated income taxes	1,048	(57)	322	544	1,857	282	2,139
Estimated income taxes	(312)	(8)	(114)	(457)	(891)	(143)	(1,034)
Net results	\$ 736	\$ (65)	\$ 208	\$ 87	\$ 966	\$ 139	\$ 1,105
For the year ended December 31, 1998							
Gross revenues from:							
Sales and transfers, including affiliate sales	\$ 2,570	\$ —	\$ 438	\$ 571	\$ 3,579	\$ 454	\$ 4,033
Sales to unaffiliated entities	218	120	509	122	969	28	997
Production costs	(1,066)	(35)	(400)	(250)	(1,751)	(150)	(1,901)
Exploration costs	(286)	(31)	(53)	(137)	(507)	(16)	(523)
Depreciation, depletion and amortization	(832)	(22)	(422)	(113)	(1,389)	(106)	(1,495)
Other expenses	(198)	—	(4)	(10)	(212)	(1)	(213)
Results before estimated income taxes	406	32	68	183	689	209	898
Estimated income taxes	(49)	(14)	(27)	(166)	(256)	(102)	(358)
Net results	\$ 357	\$ 18	\$ 41	\$ 17	\$ 433	\$ 107	\$ 540
For the year ended December 31, 1997							
Gross revenues from:							
Sales and transfers, including affiliate sales	\$ 3,492	\$ —	\$ 495	\$ 934	\$ 4,921	\$ 610	\$ 5,531
Sales to unaffiliated entities	312	165	499	178	1,154	43	1,197
Production costs	(986)	(57)	(323)	(249)	(1,615)	(192)	(1,807)
Exploration costs	(238)	(10)	(60)	(195)	(503)	(16)	(519)
Depreciation, depletion and amortization	(735)	(27)	(382)	(129)	(1,273)	(110)	(1,383)
Other expenses	(249)	—	—	(24)	(273)	9	(264)
Results before estimated income taxes	1,596	71	229	515	2,411	344	2,755
Estimated income taxes	(511)	(40)	(85)	(418)	(1,054)	(173)	(1,227)
Net results	\$ 1,085	\$ 31	\$ 144	\$ 97	\$ 1,357	\$ 171	\$ 1,528

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 \$2.8 billion and \$2.7 billion at year-end 1999 and 1998, before effects of related interest rate swaps. Interest rate swap notional amounts at year-end 1999 increased by \$845 million from year-end 1998.

Based on our overall interest rate exposure on variable rate debt and interest rate swaps at December 31, 1999 (including the interest rate and equity swap), a hypothetical two percentage points increase or decrease in interest rates would decrease or increase net income approximately \$52 million.

CURRENCY FORWARD EXCHANGE AND OPTION CONTRACTS

During 1999, the net notional amount of open forward contracts decreased \$220 million. This related mostly to a decrease in balance sheet monetary exposures.

The effect on fair value of our forward exchange contracts at year-end 1999 from a hypothetical 10% change in currency exchange rates would be an increase or decrease of approximately \$185 million. This would be offset by an opposite effect on the related hedged exposures.

PETROLEUM AND NATURAL GAS HEDGING

In 1999, the notional amount of open derivative contracts increased by \$2,207 million, mostly related to natural gas hedging.

For commodity derivatives outstanding at year-end 1999 that are permitted to be settled in cash or another financial instrument, the aggregate effect of a hypothetical 17% change in natural gas prices, a 13% change in crude oil prices and a 14% 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. During 1999, market risk exposure decreased by \$325 million. At year-end 1999, a 10% appreciation or depreciation in debt and equity prices would change portfolio fair value by about \$17 million. 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 points 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 points 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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	1999				1998			
<i>(Millions of dollars)</i>								
Revenues								
Sales and services	\$ 6,914	\$ 8,116	\$ 9,472	\$ 10,473	\$ 7,922	\$ 7,729	\$ 7,481	\$ 7,778
Equity in income of affiliates, interest, asset sales and other	276	153	205	82	225	315	226	31
	7,190	8,269	9,677	10,555	8,147	8,044	7,707	7,809
Deductions								
Purchases and other costs	5,450	6,356	7,448	8,188	6,114	5,972	5,836	6,257
Operating expenses	559	550	544	666	580	645	593	690
Selling, general and administrative expenses	290	311	270	315	276	296	290	362
Exploratory expenses	130	80	72	219	141	90	93	137
Depreciation, depletion and amortization	361	365	356	461	388	375	409	503
Interest expense, taxes other than income taxes and minority interest	216	212	214	279	249	240	237	233
	7,006	7,874	8,904	10,128	7,748	7,618	7,458	8,182
Income (loss) before income taxes and cumulative effect of accounting change	184	395	773	427	399	426	249	(373)
Provision for (benefit from) income taxes	(15)	122	386	109	140	84	34	(160)
Income (loss) before cumulative effect of accounting change	199	273	387	318	259	342	215	(213)
Cumulative effect of accounting change	—	—	—	—	(25)	—	—	—
Net income (loss)	\$ 199	\$ 273	\$ 387	\$ 318	\$ 234	\$ 342	\$ 215	\$ (213)
Total non-owner changes in equity	\$ 179	\$ 271	\$ 393	\$ 316	\$ 239	\$ 344	\$ 210	\$ (221)
Net income (loss) per common share <i>(dollars)</i>								
Basic								
Income (loss) before cumulative effect of accounting change	\$.35	\$.50	\$.71	\$.58	\$.46	\$.62	\$.38	\$ (.43)
Cumulative effect of accounting change	—	—	—	—	(.05)	—	—	—
Net income (loss)	\$.35	\$.50	\$.71	\$.58	\$.41	\$.62	\$.38	\$ (.43)
Diluted								
Income (loss) before cumulative effect of accounting change	\$.35	\$.50	\$.71	\$.58	\$.46	\$.61	\$.38	\$ (.43)
Cumulative effect of accounting change	—	—	—	—	(.04)	—	—	—
Net income (loss)	\$.35	\$.50	\$.71	\$.58	\$.42	\$.61	\$.38	\$ (.43)

See accompanying notes to consolidated financial statements.

Five-Year Comparison of Selected Financial Data

<i>(Millions of dollars)</i>	1999	1998	1997	1996	1995
For the year:					
Revenues	\$ 35,691	\$ 31,707	\$ 46,667	\$ 45,500	\$ 36,787
Net income before cumulative effect of accounting changes	\$ 1,177	\$ 603	\$ 2,664	\$ 2,018	\$ 728
Cumulative effect of accounting changes	—	(25)	—	—	(121)
Net income	\$ 1,177	\$ 578	\$ 2,664	\$ 2,018	\$ 607
Total non-owner changes in equity	\$ 1,159	\$ 572	\$ 2,601	\$ 1,863	\$ 592
Net income per common share* <i>(dollars)</i>					
Basic					
Income before cumulative effect of accounting changes	\$ 2.14	\$ 1.04	\$ 4.99	\$ 3.77	\$ 1.29
Cumulative effect of accounting changes	—	(.05)	—	—	(.24)
Net income	\$ 2.14	\$.99	\$ 4.99	\$ 3.77	\$ 1.05
Diluted					
Income before cumulative effect of accounting changes	\$ 2.14	\$ 1.04	\$ 4.87	\$ 3.68	\$ 1.28
Cumulative effect of accounting changes	—	(.05)	—	—	(.23)
Net income	\$ 2.14	\$.99	\$ 4.87	\$ 3.68	\$ 1.05
Cash dividends per common share* <i>(dollars)</i>	\$ 1.80	\$ 1.80	\$ 1.75	\$ 1.65	\$ 1.60
Total cash dividends paid on common stock	\$ 964	\$ 952	\$ 918	\$ 859	\$ 832
At end of year:					
Total assets	\$ 28,972	\$ 28,570	\$ 29,600	\$ 26,963	\$ 24,937
Debt and capital lease obligations					
Short-term	\$ 1,041	\$ 939	\$ 885	\$ 465	\$ 737
Long-term	6,606	6,352	5,507	5,125	5,503
Total debt and capital lease obligations	\$ 7,647	\$ 7,291	\$ 6,392	\$ 5,590	\$ 6,240

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

See accompanying notes to consolidated financial statements.

Texaco Inc. Board of Directors

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and Chief Executive Officer
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Chief Executive Officer
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Toronto, Canada

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Washington, DC

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Chairman and
Chief Executive Officer
Pfizer Inc.
New York, NY

THOMAS A. VANDERSLICE

Private Investor
Naples, FL

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Franklyn G. Jenifer
Sam Nunn
Charles H. Price, II
Robin B. Smith
Thomas A. Vanderslice

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Edmund M. Carpenter

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PATRICK J. LYNCH Senior Vice President and Chief Financial Officer	EUGENE CELENTANO Vice President International Marketing & Manufacturing	ELIZABETH P. SMITH Vice President Investor Relations & Shareholder Services	GEORGE J. BATAVICK Comptroller
JOHN J. O'CONNOR Senior Vice President Worldwide Exploration & Production	JAMES F. LINK Vice President Finance & Risk Management	ROBERT A. SOLBERG Vice President Worldwide Upstream Commercial Development	IRA D. HALL Treasurer
GLENN F. TILTON Senior Vice President Global Businesses	JAMES R. METZGER Vice President and Chief Technology Officer	JANET L. STONER Vice President Human Resources	MICHAEL H. RUDY Secretary
WILLIAM M. WICKER Senior Vice President Corporate Development	ROBERT C. OELKERS Vice President Worldwide Supply & Trading Operations		

CHANGES

- > George J. Batavick was elected Comptroller of Texaco Inc., effective April 1, 1999.
- > C. Robert Black, Senior Vice President of Texaco Inc., retired on May 1, 1999, after 41 years of service.
- > Stephen M. Turner, Senior Vice President of Texaco Inc., retired on June 1, 1999, after 10 years of service.
- > James F. Link was elected Vice President of Texaco Inc., effective October 1, 1999.
- > Claire S. Farley, Vice President of Texaco Inc., retired on October 1, 1999, after 18 years of service.
- > Ira D. Hall was elected Treasurer of Texaco Inc., effective October 1, 1999.
- > Kjestine M. Anderson, Secretary of Texaco Inc., retired on December 31, 1999, after 20 years of service.
- > Michael H. Rudy was elected Secretary of Texaco Inc., effective January 1, 2000.
- > Bruce S. Appelbaum was elected Vice President of Texaco Inc., effective March 1, 2000.
- > Clarence P. Cazalot, Jr., Vice President of Texaco Inc., retired on March 3, 2000, after 27 years of service.

Investor Information

COMMON STOCK — MARKET AND DIVIDEND INFORMATION:

Texaco Inc. common stock (symbol TX) is traded principally on the New York Stock Exchange. As of February 24, 2000, there were 198,698 shareholders of record. In 1999, Texaco's common stock

price reached a high of \$70¹/₁₆, and closed December 31, 1999, at \$54⁵/₁₆.

	Common Stock Price Range				Dividends	
	High	Low	High	Low	1999	1998
	1999	1998	1998	1998	1999	1998
First Quarter	\$ 59 ³ / ₁₆	\$ 44 ⁹ / ₁₆	\$ 65	\$ 49 ¹ / ₁₆	\$.45	\$.45
Second Quarter	70¹/₁₆	55¹/₈	63 ³ / ₄	55 ³ / ₄	.45	.45
Third Quarter	68¹/₂	60⁵/₁₆	64 ⁷ / ₈	55 ¹ / ₄	.45	.45
Fourth Quarter	67³/₁₆	52³/₈	63 ⁷ / ₈	50 ¹ / ₄	.45	.45

STOCK TRANSFER AGENT AND SHAREHOLDER COMMUNICATIONS

FOR INFORMATION ABOUT TEXACO
OR ASSISTANCE WITH YOUR ACCOUNT,
PLEASE CONTACT:

Texaco Inc.
Investor Services
2000 Westchester Avenue
White Plains, NY 10650-0001
Phone: 1-800-283-9785
Fax: (914) 253-6286
E-mail: invest@texaco.com

NY DROP AGENT

ChaseMellon Shareholder Services
120 Broadway – 13th Floor
New York, NY 10271
Phone: (212) 374-2500
Fax: (212) 571-0871

CO-TRANSFER AGENT

Montreal Trust Company
151 Front Street West – 8th Floor
Toronto, Ontario, Canada M5J 2N1
Phone: 1-800-663-9097
Fax: (416) 981-9507

SECURITY ANALYSTS AND INSTITUTIONAL
INVESTORS SHOULD CONTACT:

Elizabeth P. Smith
Vice President, Texaco Inc.
Phone: (914) 253-4478
Fax: (914) 253-6269
E-mail: smitthep@texaco.com

ANNUAL MEETING

Texaco Inc.'s Annual Stockholders Meeting will be held at Purchase College, The State University of New York, in Purchase, NY, on Wednesday, April 26, 2000. A formal notice of the meeting, together with a proxy statement and proxy form, is being mailed to stockholders with this report.

INVESTOR SERVICES PLAN

The company's Investor Services Plan offers a variety of benefits to individuals seeking an easy way to invest in Texaco Inc. common stock. Enrollment in the Plan is open to anyone, and investors may make initial investments directly through the company. The Plan features dividend reinvestment, optional cash investments, and custodial service for stock certificates. Open an account or access your registered shareholder account on the Internet through our new TexLink connection at www.texaco.com. Texaco's Investor Services Plan is an excellent way to start an investment program for family or friends. For a complete informational package, including a Plan prospectus, call 1-800-283-9785, e-mail at invest@texaco.com, or visit Texaco's Internet home page at www.texaco.com.