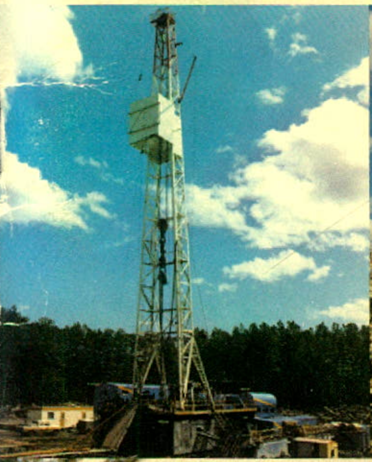
Texaco Canada Inc.

Annual Report 1981



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Texaco Canada Inc.
90 Wynford Drive
Don Mills, Ontario M3C 1K5

Contents

The Annual Meeting of Shareholders of Texaco Canada Inc. will be held at the Company's registered office at 90 Wynford Drive, Don Mills, Ontario, on Friday, April 23, 1982, at 10:30 a.m.

On peut obtenir un exemplaire français du présent rapport annuel en s'adressant au secrétaire général et chef des Affaires publiques de la compagnie, 90 Wynford Drive Don Mills, Ontario M3C 1K5

The use in this report of such terms as *Texaco Canada, Corporation, Company, organization, we, us, our* and *its*, when referring to Texaco Canada Inc. or to its subsidiaries and affiliates either individually or collectively, is only for convenience and is not intended to be an accurate description of corporate relationships.

Cover: Large modern delivery vehicles capable of transporting 56 000 litres of product have upgraded Texaco Canada's tank truck fleet, in keeping with the company's program to improve efficiency while reducing operating costs. The smaller inset pictures depict key facets of the company's integrated operations.

Subsidiary Companies

Texaco Canada Resources Ltd.
Oilship Limited
The Great Eastern Oil & Import Company, Ltd.
McColl-Frontenac Oil Co. Ltd.
Public Fuel Transmission Systems Limited
Lowry Fuels Limited

Principal Investments and Percentage Interest

Federated Pipe Lines Ltd.	50%
Trans-Northern Pipelines Inc.	33.33%
Alberta Products Pipe Line Ltd.	20%
Montreal Pipe Line Company Limited	16%

Transfer Agents in Canada:

Montreal Trust Company of Canada, Montreal, Toronto, Winnipeg, Regina, Calgary and Vancouver

Registrars in Canada:

The Royal Trust Company, Montreal, Toronto, Winnipeg, Regina, Calgary and Vancouver

Transfer Agents and Registrars in the United States:

The Royal Bank & Trust Company
68 William Street, New York, N.Y.

Officers

R. W. Sparks
Chairman of the Board

Roland M. Routhier
President and Chief Executive Officer

J. L. Morrison
Executive Vice-President

O. C. Cleyn
Vice-President, Eastern Canada and Region Manager

A. J. Galipeault
Vice-President and General Counsel

K. D. Keegan
Vice-President and Treasurer

J. M. Murray
Vice-President and General Manager, Refining

C. S. Ramsay
Vice-President and General Manager, Employee Relations

N. E. Taylor
Vice-President and General Manager, Marketing

S. J. Walker
Vice-President and General Manager, Supply and Distribution

J. C. Wattie
Vice-President, Personnel and Corporate Services

E. J. Little
Corporate Secretary and Director of Public Affairs

P. M. Taylor
Corporate Tax Officer

D. L. West
Comptroller

Highlights

Financial

	1981	1980	1979
		(Millions of dollars)	
Revenues	**$4,461**	$3,572	$2,685
Net income	**316**	373	264
Cash dividends	**119**	92	72
Funds provided by operations	**404**	461	387
Taxes and crown royalties	**1,801**	1,141	920
Capital and exploratory expenditures	**209**	224	137
Total capital employed at year-end	**2,239**	2,066	1,751
Common shareholders' equity at year-end	**1,478**	1,280	998
Working capital at year-end	**757**	661	478
Long-term debt at year-end	**75**	85	94

Rate of Return

On average total capital employed	**14.9%**	19.9%	16.4%

Per Common Share Data

Net income	**$ 2.45**	$ 2.92	$ 2.01
Cash dividends	**.82**	.585	.42
Funds provided by operations	**3.35**	3.82	3.21
Shareholders' equity at year-end	**12.25**	10.62	8.28

Operating

		(Thousands of cubic metres daily)	
Gross production of crude oil and natural gas liquids	**23.5**	24.0	26.7
Refinery runs	**28.2**	29.8	30.8
Petroleum product sales	**31.6**	33.8	32.9
		(Millions of cubic metres daily)	
Natural gas sales	**3.3**	2.4	2.2
Estimated gross proved recoverable reserves:		(Cubic metres)	
Crude oil and natural gas liquids (millions)	**71.8**	81.6	86.3
Natural gas (billions)	**65.2**	60.9	58.8

Per common share information has been adjusted for the four-for-one split which occurred on August 15, 1980.

The Metric System

Information in this Annual Report on all company operations is provided in the International System of Units, commonly called the metric system. Approximate conversion factors to metric units are as follows:

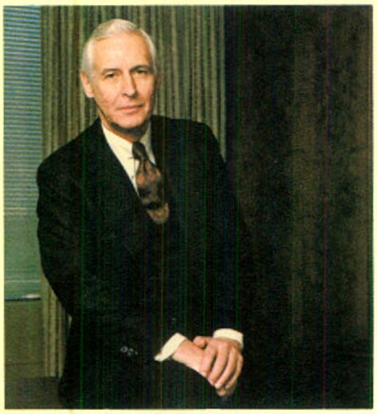
One cubic metre contains about 6.29 barrels of liquids or about 35.3 cubic feet of gas.

One hectare is about 2.47 acres.

One kilometre is about 0.62 miles.

One tonne is about 2,200 pounds.

To the Shareholders:



Roland M. Routhier

The two factors having the greatest impact on petroleum industry activities in Canada during the past year were government energy policies and reduced demand for refined petroleum products. The government energy policies constitute a massive new tax program which has resulted in higher energy costs to Canadian consumers and, in turn, has contributed significantly to the reduction in demand. The government policies also discriminate severely against companies which are not majority-owned and controlled by Canadians.

Consequences of Policies

The principal consequences of current government policies, particularly the National Energy Program, were: Curtailment of cash flow and of the investment capability of the industry; a serious decline in domestic exploration and drilling activity; the exodus of drilling rigs, investment capital and experienced personnel from Canada; and sharp increases in petroleum product prices.

The full impact of some of the most harmful and discriminatory provisions of the National Energy Program is still to be felt. The program already has made the goal of oil self-sufficiency for Canada much more difficult to achieve.

The cost to Canada of reliance on foreign oil was high in 1981. The total bill for importing more than one-fifth of the country's crude oil needs amounted to some $7 billion—an outlay that was only partially offset by revenues from this country's petroleum exports. Moreover, current energy policies are contributing to still greater and more extended dependence on foreign sources as Canada's production of conventional crude oil continues to decline.

Conservation and substitution measures will help the crude oil supply-demand balance. But oil self-sufficiency and security of supply for Canada cannot be attained, even by the end of the century, unless all segments of the producing industry are permitted to play their full part. The larger companies such as Texaco Canada have historically provided Canadians with much of their petroleum requirements. They must be allowed to generate and retain enough cash flow to be able to invest in the all-out drive that is necessary to find and develop sufficient new domestic oil reserves, from the traditional areas as well as from the frontier areas offshore, the Arctic regions and the oil sands. The highest priority needs to be given to measures which encourage such a drive.

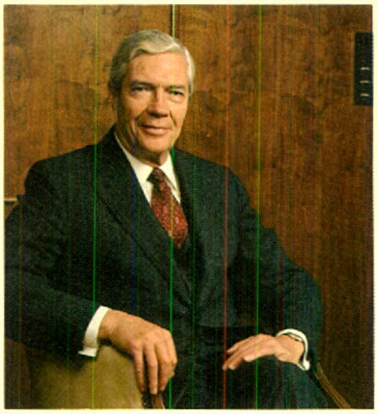
Inadequate Returns

It was hoped that the energy pricing agreements reached by Ottawa with the producing provinces in 1981 would do much to rectify the situation. Unfortunately, these agreements, by imposing massive new taxes on the petroleum industry, have fallen far short of permitting the generation of risk capital on the scale required.

The federal-provincial agreements, while allowing improved returns to producers for "new oil" discovered after December 31, 1980, provide producers with a return for so-called "old oil" which is entirely inadequate to finance the finding and development of "new oil".

The inadequate return for "old oil" results primarily from the combination of heavy provincial royalties and taxes and the federally imposed Petroleum and Gas Revenue Tax, which currently is set at 16 per cent. These royalties and taxes are not deductible for the determination of taxable income and are only partially offset by "resource allowances" which were introduced in lieu of deductibility. Consequently, substantial portions of the revenues of Texaco Canada and other oil companies are subject to the onerous burden of double taxation.

There are other regressive measures in the National Energy Program which will adversely affect Texaco



R. W. Sparks

Canada and a large segment of the petroleum industry. They include a back-in provision entitling the Canadian Government through a Crown corporation to a 25 per cent interest—retroactively and without adequate compensation to the legitimate holders—in exploration rights on Canada lands. Another of the harmful measures is the proposed Petroleum Incentive Program which discriminates against companies that are not majority-owned and actually controlled by Canadians.

A strong and healthy petroleum industry is vital to Canada's continued growth and progress. The industry will be able to make its essential contributions to the country's security of oil supply, balance of payments position, and to employment and the economy as a whole only if the confiscatory, retroactive and discriminatory provisions of the National Energy Program are significantly modified or eliminated. Consultations by governments with the petroleum industry to help develop such realistic and necessary changes in energy policies should be undertaken as quickly as possible. To date, the industry's recommendations in this area have been largely unheeded.

Texaco Canada will continue to pursue a program of exploration throughout Canada, including the frontier areas, to the extent that economic opportunities appear to be commensurate with the risks involved. The level of the program will, however, be considerably lower than would be the case if the company received adequate returns from existing production and if more encouraging policies for frontier exploration prevailed.

The company is in a fundamentally strong position. It has the resources, the facilities and the skilled organization needed to respond to the opportunities that should lie ahead.

Restrictive Trade Practices Hearings

Public hearings by the Restrictive Trade Practices Commission into the state of competition in the petroleum industry began in Ottawa in October, 1981. Regional hearings were held in cities across Canada from December through mid-February 1982, and further hearings are scheduled for Ottawa in March and April. The hearings arise from the "Bertrand Report" issued in March 1981 by the Director of Investigation and Research, under the Combines Act. This report contains unfounded allegations of uncompetitive practices and of gross overcharging of consumers by Texaco Canada and makes similar allegations regarding other integrated oil companies.

The company has publicly stated that Texaco Canada competes fairly and operates efficiently and in the best interests of its customers, dealers, shareholders and of Canadians generally. At the hearings, the company emphasized that several of the recommendations contained in the Bertrand Report would, if implemented, dramatically change and have negative effects on the structure and conduct of the petroleum business in Canada and on Canadian consumers. The Commission was urged to expunge the Bertrand Report from the record.

Earnings and Operations

The consolidated net income of Texaco Canada Inc. for the year ended December 31, 1981, amounted to $316.3 million, or $2.45 a common share. This compares with $373.4 million, or $2.92 a share for 1980.

Increased revenue resulting from higher prices for crude oil, natural gas liquids and refined products was more than offset by higher taxes, increased costs and revenue reductions due to the lower sales volumes. The decline in the company's sales reflected the reduction in Canadian consumer demand.

The company's earnings for 1981 were reduced by $71.5 million as a result of the Federal Petroleum and Gas Revenue Tax which was imposed as part of the National Energy Program.

Texaco Canada's gross production of crude oil and natural gas liquids was 2.5 per cent lower for the year, averaging 23 500 cubic metres daily compared with 24 000 cubic metres in 1980. Refinery runs of 28 200 cubic metres daily were 5.4 per cent lower than for 1980. Petroleum product sales averaged 31 600 cubic metres a day, a decline of 6.8 per cent. Sales of natural gas of 3.3 million cubic metres daily were 35.8 per cent higher than for the previous year.

The company completed or participated in the completion of 33 exploration and 81 development wells in 1981, mainly in Alberta. The exploratory drilling resulted in six oil and eight gas discoveries, while development drilling resulted in the completion of 29 oil wells and 46 gas wells.

Texaco Canada's marketing operations are undergoing major consolidations to increase earnings by reducing costs and increasing productivity. The company's ongoing program designed to eliminate lower-volume, higher-cost retail and wholesale units while expanding more efficient ones has resulted in significant reductions in the number of retail and wholesale facilities since 1975. At the same time, the total volume of sales has increased during this period.

The new pipeline sales terminal at Calgary went into operation in December 1981. This terminal receives products from the Edmonton refinery and provides a highly efficient system of distributing products to the company's markets in southern Alberta and southeastern British Columbia.

In 1981, net funds provided by operations amounted to $404.5 million, equivalent to $3.35 a common share, compared with $460.8 million, or $3.82 a share, in 1980.

Dividend payments on the common shares in 1981 totalled $98.9 million, or $0.82 a share including an increase of six cents to 25 cents a share, declared on October 30 and payable on November 30. Dividends paid on common shares in 1980 amounted to $70.5 million, or $0.585 per share.

On November 20, 1981 the Board of Directors considered and recommended acceptance of an offer by Texaco International Financial Corporation (TIFCO), a wholly-owned subsidiary of Texaco Inc., to purchase for $360 a share any or all of the First Preferred shares, Series A of Texaco Canada Inc. That price represented a premium over the equivalent market price of the company's common shares into which the First Preferred shares, Series A, could be converted. The offer also provided for additional compensation in the event of certain corporate developments occurring prior to June 1, 1983. As a result of the offer 9,528 shares were tendered, representing 85 per cent of the 11,207 First Preferred shares, Series A outstanding as of December 8, 1981.

The corporation's President, Roland M. Routhier, was appointed to the additional position of Chief Executive Officer of Texaco Canada Inc. by the Board of Directors, effective November 1, 1981. Mr. Routhier succeeds R.W. Sparks as Chief Executive Officer. Mr. Sparks, who remains as Chairman of the Board until the 1982 Annual Meeting, took early retirement as an employee of the corporation at his own request, effective October 31, after more than 27 years of dedicated service and leadership, including six years as Chief Executive Officer.

We wish to express our appreciation to the employees of Texaco Canada for their efficiency, loyalty, and teamwork and to the shareholders for their continuing support and confidence.

On behalf of the Board of Directors,

R. W. Sparks
Chairman of the Board

Roland M. Routhier
President and Chief Executive Officer

Don Mills, Ontario
March 16, 1982

Energy Resources
Mineral Interests

OIL AND GAS RIGHTS

At the end of 1981, Texaco Canada held an interest in oil and gas rights in Canada covering 7.2 million hectares compared with 6.0 million hectares at December 31, 1980. The increase in rights results primarily from an internal reclassification of option lands to inventory, although surrenders were made of certain holdings in the Arctic Islands and Northwest Territories, which had been evaluated as having low potential.

During the year the company acquired additional oil and gas rights in eastern Canada in the Quebec lowlands, south of the St. Lawrence River between Montreal and Quebec City. These included some 119 200 hectares under exploration licenses from the Quebec Government and a 50 per cent interest in 12 000 hectares earned by drilling an exploratory test.

Subject to approval by the Guatemalan government, the company is acquiring, under a farm-in arrangement, a 25 per cent interest in a petroleum operations contract covering some 156 000 hectares in northwestern Guatemala. A subsidiary of Texaco Inc. is the operator and exploratory drilling and evaluation work in the area are in progress.

OIL SANDS RIGHTS

Texaco Canada holds some 238 000 hectares of oil sands leases and permits in Alberta containing an estimated 12 billion cubic metres of bitumen. Reserves attributable to these resources are not included in the estimate of the company's recoverable reserves because no portion is yet economically recoverable.

COAL LEASES

The company continued to hold leases on some 52 000 hectares in central Alberta containing an estimated three billion tonnes of subbituminous coal.

MINERAL PROSPECTING RIGHTS

Texaco Canada's mineral exploration program is focused on uranium and other mineral deposits discovered in the course of uranium exploration.

During 1981, the company completed an exploration program to earn interests ranging from 33.3 per cent to 37.5 per cent in 139 000 hectares in north Saskatchewan, adjacent to the Athabasca basin. Exploration continued in the Yukon, and at year-end the company held a 90 per cent interest in 4 000 hectares of claims.

Acreage holdings in the Northwest Territories in which Texaco Canada holds 30 to 50 per cent interests were reduced from 170 000 hectares to 73 000 hectares as certain mineral prospecting permits were allowed to expire after further evaluation.

W. A. Gatenby

Mr. Gatenby, a native of Saskatchewan, was appointed President and Chief Executive Officer of Texaco Canada Resources Ltd. September 1, 1981 replacing Mr. D. E. Hyer who took up a position with Texaco Inc. in Houston.

Mineral Interests

	Thousands of Hectares December 31,			
	1981		1980	
OIL AND GAS RIGHTS	**Gross**	**Net**	Gross	Net
Canada				
Western Provinces	**1 145**	**684**	1 203	711
Quebec Onshore	**143**	**128**	–	–
Eastern Canada Offshore*	**5 282**	**2 591**	3 902	1 941
Beaufort Sea	**337**	**314**	337	314
Other	**332**	**215**	586	427
TOTAL	**7 239**	**3 932**	6 028	3 393
OIL SANDS RIGHTS				
Alberta	**238**	**232**	238	232
COAL LEASES				
Alberta	**52**	**52**	52	52
MINERAL PROSPECTING RIGHTS				
Saskatchewan	**139**	**49**	–	–
Northwest Territories	**73**	**22**	170	51
Yukon	**4**	**4**	2	2
TOTAL	**216**	**75**	172	53

*The 1981 figures include 1 320 000 gross hectares and 660 000 net hectares to reflect a change of internal classification from option rights in 1980 to inventory in 1981.

Exploration and Development

EXPLORATION

Proprietary seismic surveys were conducted in high priority areas of Alberta and northeastern British Columbia. Texaco Canada also conducted a marine seismic program off the coast of Labrador and participated in similar programs in the Gander area offshore Newfoundland and the Scotian Shelf offshore Nova Scotia.

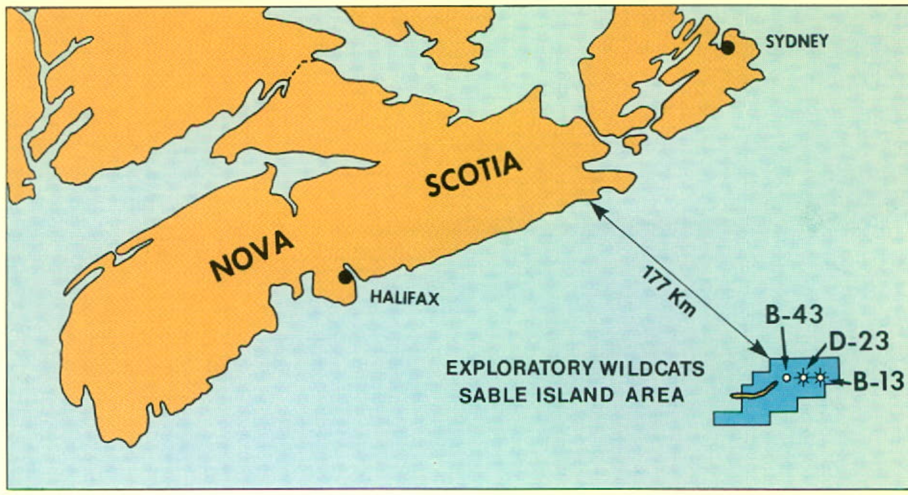
Exploration drilling was carried out in west central and northwestern Alberta, northeastern British Columbia, the Quebec lowlands, the Sable Island area offshore Nova Scotia, and in the Republic of Guatemala.

Through this drilling activity, the company participated in the completion of 33 wildcat wells (18 of which were begun prior to 1981) resulting in six oil discoveries, eight gas discoveries, and 19 dry holes, for a success ratio of 42 per cent.

At West Pembina, the company completed four wholly owned wildcat wells of which two were oil discoveries and one a gas discovery. In the same area, five wildcat wells were drilled in which Texaco Canada had varying interests, resulting in two oil and two natural gas discoveries; two additional wildcats were being drilled at year-end. Elsewhere in Alberta, Texaco Canada participated in the completion of 17 wildcat wells, of which two were oil discoveries, four were gas discoveries and 11 were dry holes.

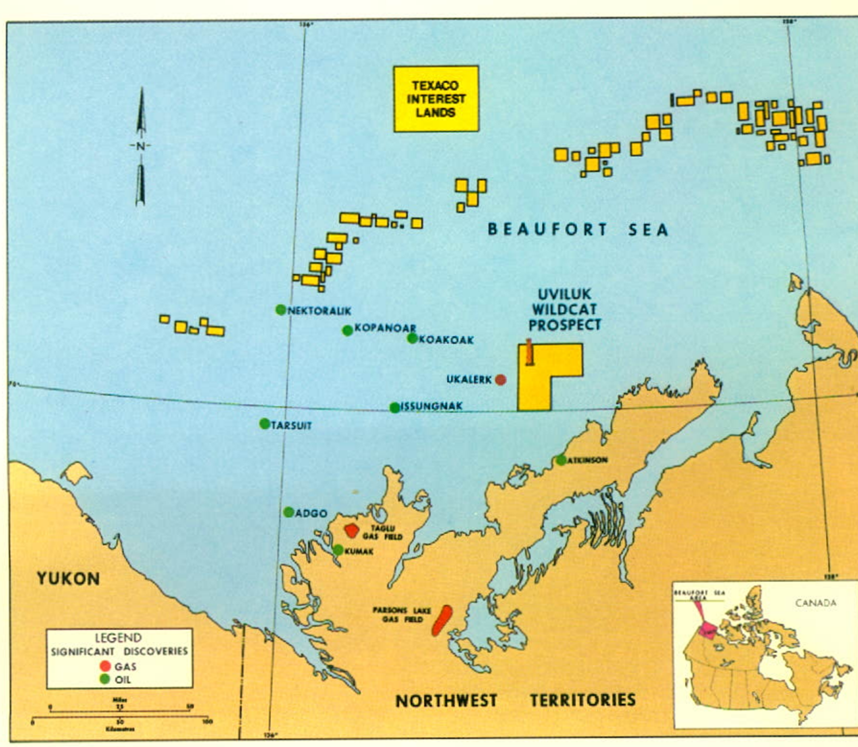
In northeastern British Columbia, Texaco Canada completed five wildcat wells of which one was a gas discovery and four were dry holes.

In the Quebec lowlands, the company completed one dry hole and another wildcat well is under evaluation.



Texaco Canada has an 18 per cent interest in the Mobil Tex Pex Venture B-13 well, a 1981 offshore exploratory well near Sable Island on the Scotian Shelf, which tested significant flows of natural gas and condensate. The combined test rates of four separate zones totalled 1.9 million cubic metres of natural gas and 141 cubic metres of condensate per day. Several other zones tested gas in smaller volumes. This well was a stepout wildcat about three kilometres east of the 1979 exploratory test, Mobil Tex Pex Venture D-23, which also yielded substantial rates of natural gas and condensate from several zones. A third exploratory well on the structure, Mobil Tex Pex Venture B-43, located about three kilometres west of the D-23 discovery, was being drilled at year-end. Texaco Canada's interest in each of these latter two wells is also 18 per cent. Additional exploratory drilling is planned for 1982 to further evaluate the commercial development potential of the area.

Construction of a drilling island was started in 1981 in the Beaufort Sea on a 106 000 hectare block of permits farmed out by Texaco Canada. The drilling of an exploratory well on this island to evaluate the Uviluk prospect is expected to begin in 1982. The location is considered prospective for both oil and gas. Texaco Canada's retained interest in the block after the farmout earnings requirements are fulfilled will be 50 per cent.



Elsewhere in the Beaufort Sea, the company has a 90 per cent interest in a group of strategically located leases encompassing 231 000 hectares to the north of the Kopanoar and Koakoak oil and gas discovery wells completed in 1981. The nearest of these leases is located 23 kilometres from the Kopanoar discovery. The leases are situated in an area where the operating environment is more difficult—due to the water depth and the northerly location—than it has been for other wells drilled to date in the Beaufort Sea. The options for further exploration are under review.

In northwestern Guatemala where the company, subject to government approval, has certain rights to acquire an interest in a petroleum operations contract, one exploratory well which tested oil in early 1981 was retested in January 1982 at a rate of 493 cubic metres per day of heavy crude. A second exploratory well was a dry hole, while a third exploratory well was being drilled at year-end. Evaluation of the potential of the area is continuing.

Exploratory Drilling Completions

	Number of Wells			
	1981		1980	
	Gross	**Net**	Gross	Net
Oil	**6**	**4.6**	4	3.1
Gas	**8**	**3.7**	13	2.7
Dry	**19**	**9.2**	12	4.6
Total	**33**	**17.5**	29	10.4

DEVELOPMENT

Texaco Canada participated in the completion of 81 development wells during 1981. Of the total, 29 were completed as oil wells, primarily in the Pembina, Swan Hills and Nipisi areas of Alberta. Forty-six gas wells were completed, mainly in the Deep Basin and Alderson areas of Alberta.

The total of 81 development wells in 1981 compares with 211 wells in 1980. A large portion of the 1980 well completions resulted from extensive development drilling in the Alderson shallow gas area and from follow-up development drilling to prior Nisku discoveries in the West Pembina area.

During the year, 93 per cent of all the development wells in which Texaco Canada was a participant were successfully completed as oil or gas wells.

Enhanced oil recovery projects are being implemented to maximize oil recovery from the Nisku pools in the West Pembina area. A total of 10 enhanced recovery schemes, four of which are hydrocarbon miscible floods and six waterfloods, have been initiated there. Two additional miscible floods and two additional waterfloods are planned for 1982. These are expected to add significantly to recoverable reserves of crude oil.

Expansion of the solution gas plant and construction of new fractionation facilities, at Bonnie Glen, were started in 1981 and are scheduled for completion in the second quarter of 1982. These facilities will provide for increased recovery and fractionation of natural gas liquids from existing gas production. The enlarged gas processing capacity will be 2.8 million cubic metres per day and the new fractionation capacity will be 2 800 cubic metres per day of liquids. These facilities are expected to add 1 700 cubic metres per day to the company's production of natural gas liquids in the second half of 1982.

Texaco Canada's gas sales from the Elmworth field in northwestern Alberta are expected to increase in 1982 as a result of additions to gas reserves established by drilling and reservoir performance. To maintain the increased sales, the gas gathering and processing facilities are being expanded from a capacity of 5.7 million to 8.5 million cubic metres per day, with completion scheduled for mid-1982. The company's interest in these facilities is 31.6 per cent.

The first phase of the Brainard gas plant, in northwestern Alberta, was completed in late 1981. The company has a 50 per cent interest in this plant which has a design capacity of 1.0 million cubic metres per day. The company's share of natural gas sales from this new facility is expected to be 340 000 cubic metres per day in 1982. Start of construction of the second phase to handle sour gas is planned for 1982.

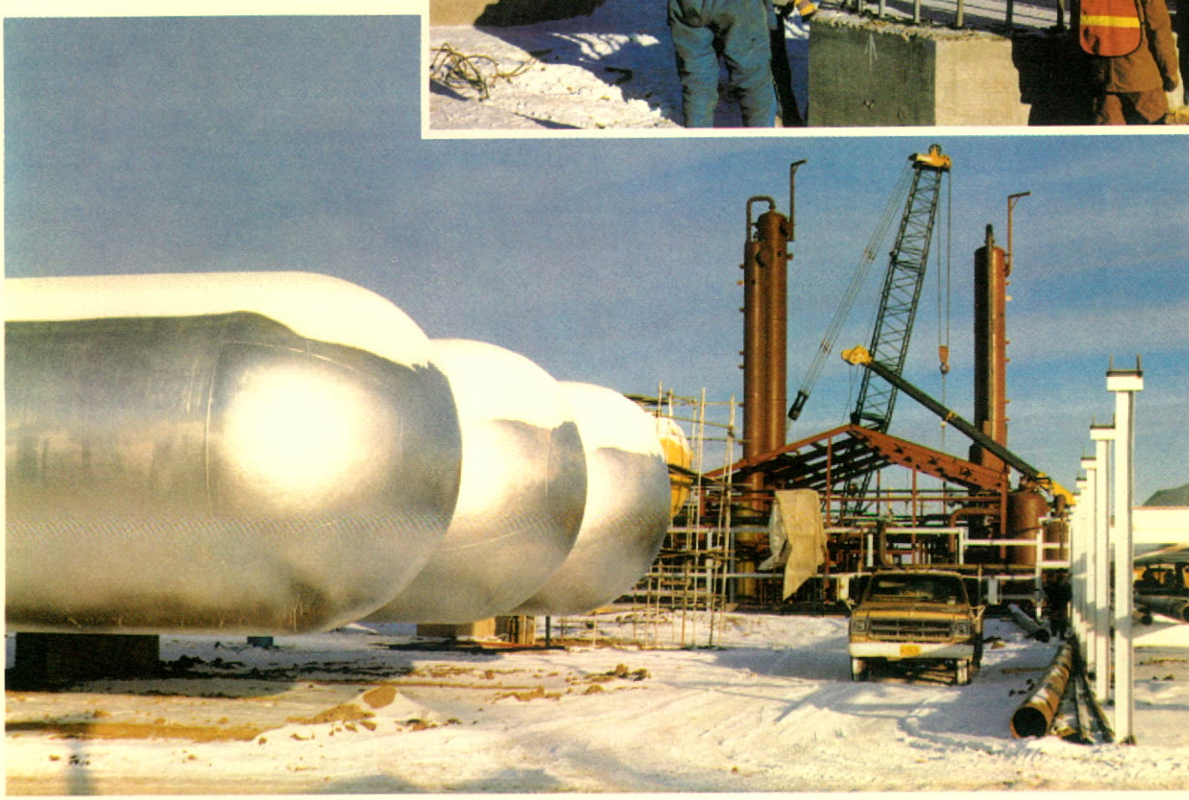
The wholly-owned natural gas processing plant in the Open Creek area of central Alberta was completed and placed on stream in March 1981. Contract sales of gas from this plant are at a rate of 129 000 cubic metres per day.

During the year, Texaco Canada entered into three agreements with ProGas Limited for the sale of natural gas from the Brainard, Valhalla and Wabasca areas. Sales from Brainard and Valhalla will start in early 1982 and from Wabasca during 1983. Total company sales volume from the three areas is expected to reach 858 000 cubic metres per day by early 1983.

Development Drilling

	Number of Wells			
	1981		1980	
	Gross	**Net**	Gross	Net
Oil	**29**	**12.3**	76	18.3
Gas	**46**	**11.7**	131	39.9
Dry	**6**	**1.7**	4	2.5
Total	**81**	**25.7**	211	60.7

Expansion of the Bonnie Glen gas plant will increase its natural gas liquids production capacity by 1 700 cubic metres per day. A butane splitter vessel arrives at the site (above) and (right) is guided into position. Below, a general view of the construction site.



Production and Reserves

CRUDE OIL AND NATURAL GAS LIQUIDS

Gross production of crude oil and natural gas liquids averaged 23 500 cubic metres per day in 1981, down 2.5 per cent from 1980. This resulted from a reduction of crude oil production of some 3.3 per cent which was only partially offset by an increase of 5.2 per cent in production of natural gas liquids.

The company's 1981 production of total liquids was about 10 per cent below capacity. This was due primarily to restricted rates of allowable production in Alberta during September, October and November. The restriction resulted from a combination of reduced total demand and commitments for imported crude made by a number of refiners in anticipation of continued Alberta production cutbacks which cutbacks were phased out following the Alberta-Ottawa energy agreement of September 1. Reduced demand reflects the influence of Canada's economic slowdown and sharply higher prices for petroleum products.

NATURAL GAS SALES

Sales of natural gas increased 35.8 per cent to 3.3 million cubic metres daily in 1981 from an average 2.4 million cubic metres per day in the previous year. This increase was attributable mainly to new gas sales from Open Creek and increased sales from the Elmworth area.

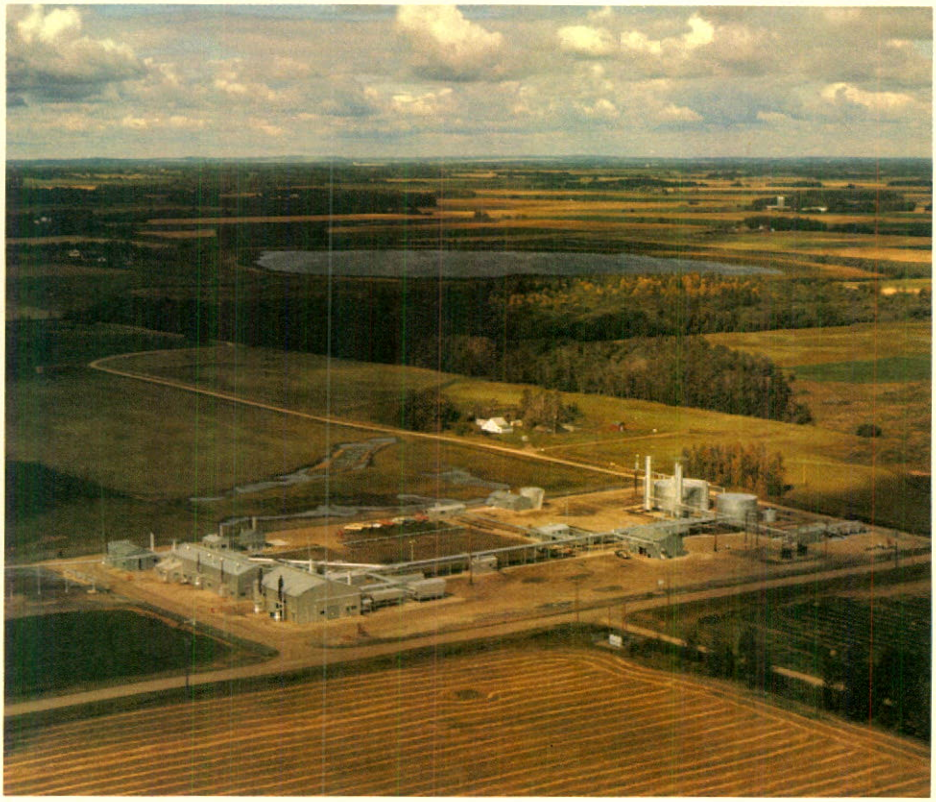
Gross Production of Crude Oil and Natural Gas Liquids

	Thousands of Cubic Metres Daily	
Crude Oil	**1981**	1980
Alberta		
Bonnie Glen	**8.6**	8.7
Wizard Lake	**7.1**	7.3
Pembina	**1.9**	1.8
Swan Hills	**1.4**	1.7
Nipisi	**0.7**	0.6
Other	**1.2**	1.4
Total	**20.9**	21.5
British Columbia	**0.2**	0.2
Manitoba and Saskatchewan	**0.1**	0.2
Total Crude Oil	**21.2**	21.9
Natural Gas Liquids	**2.3**	2.1
Total Crude Oil and Natural Gas Liquids	**23.5**	24.0

RESERVES

Texaco Canada's gross proved recoverable reserves of crude oil and natural gas liquids at year-end were estimated at 71.8 million cubic metres, compared with 81.6 million cubic metres a year earlier. Additions, which totalled 0.9 million cubic metres, resulted primarily from new discoveries and pool extensions in the West Pembina area. Deductions, which amount to 10.7 million cubic metres, included production of 8.5 million cubic metres and downward revision of prior year estimates of 2.2 million cubic metres.

The company's estimated gross proved reserves of natural gas were 65.2 billion cubic metres at the end of 1981. This was an increase of 4.3 billion cubic metres, or 7.1 per cent, over the reserves at the end of the previous year, resulting mainly from additions in the Deep Basin area which more than offset production during the year.

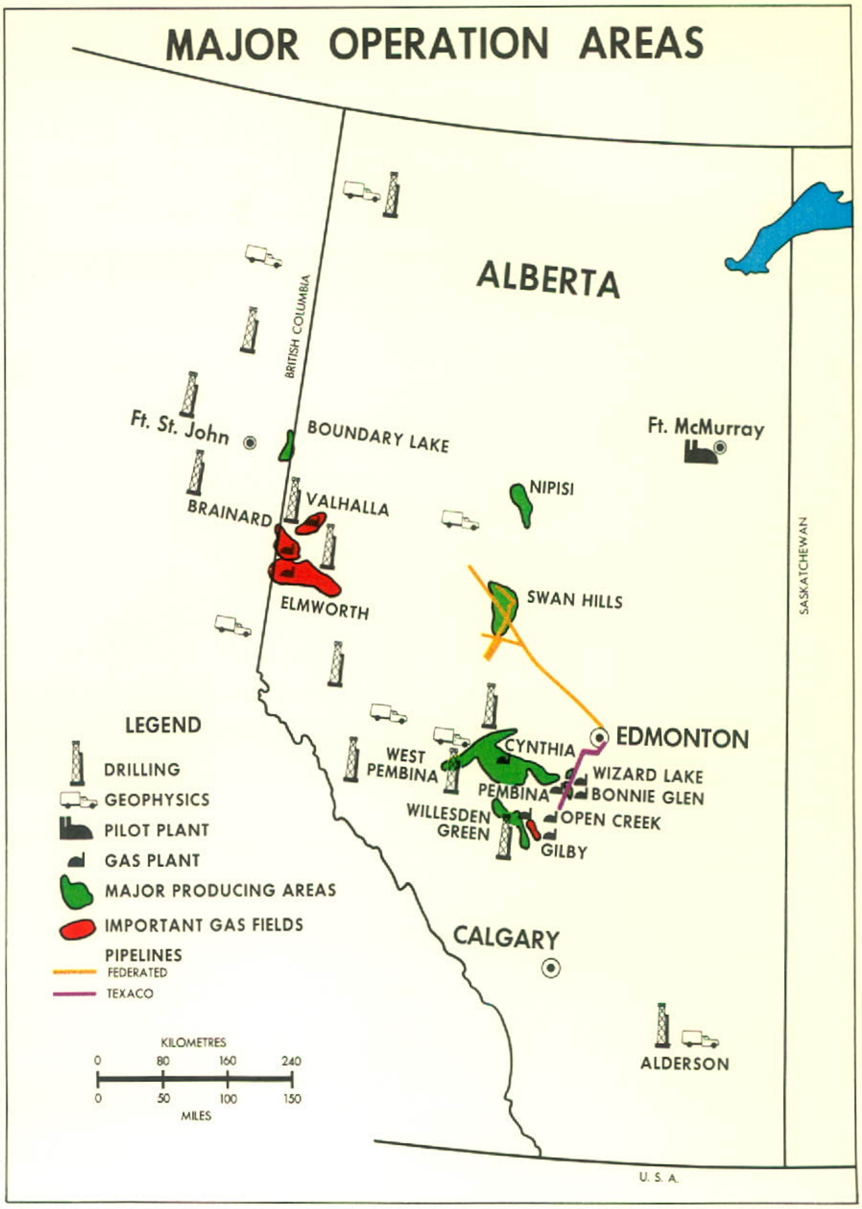


The Wizard Lake producing facility in Alberta is Texaco Canada's largest, with a capacity of 11 100 cubic metres of oil per day.

Estimated Proved Recoverable Reserves of Hydrocarbons as of the end of the year

	Millions of Cubic Metres			
	1981		1980	
	Gross	**Net**	Gross	Net
Crude Oil	**58.5**	**36.5**	67.9	42.8
Gas Liquids	**13.3**	**9.3**	13.7	9.6
Total	**71.8**	**45.8**	81.6	52.4
	Billions of Cubic Metres			
Natural Gas	**65.2**	**44.3**	60.9	43.7

Net reserves are the company's share of reserves after deduction of royalties that will be due others when the oil, gas or natural gas liquids are produced. Royalties on provincial and federal lands are subject to change by legislation or regulation and are generally partly dependent on selling price. Net reserves are therefore re-estimated annually, following generally accepted guidelines, to reflect the current regulations and pricing outlook.



Oil Sands Research

Research and development of in-situ methods for recovery of bitumen from the Athabasca Oil Sands continued in 1981 at Texaco Canada's pilot project near Fort McMurray, Alberta. The third well of a three horizontal well program was completed and steam is being injected at this unique project to test its efficiency in bitumen recovery. An active field program was continued to improve methods for separating produced bitumen, which is largely in the form of a finely dispersed emulsion, from the produced water.

Earthwork, the construction of roads, and the installation of tanks and power lines were completed on the Steepbank Lease about 60 kilometres northeast of Fort McMurray. This is the site of a second pilot project which may be identified in the future to further develop in-situ recovery technology.

During the 1980-1981 winter drilling season 41 core holes were drilled on company oil sands leases, mainly in the Athabasca area, to further evaluate these holdings. This completes a five-year program in accordance with present leasehold requirements and provides geological data needed for planning.

Texaco Canada's in-situ recovery field work is supported by a number of laboratory research programs. The largest of these is a proprietary research program being conducted by the Alberta Research Council under a contract with the company. This continues a relationship of many years in which Texaco Canada contributed its technology and experience and was a major sponsor of research into in-situ recovery undertaken by this eminent research organization.

The company also sponsors oil sands research projects at the University of Alberta and the Canadian Centre for Mineral and Energy Technology, and participates in other research programs related to oil sands.

Petroleum Products
Refining

There was a significant reduction in demand for all types of petroleum products in 1981 with the demand for some products falling more rapidly than for others. As a consequence, the Nanticoke refinery had some difficulties in meeting the product yields required by the market place.

Expansion of the Edmonton refinery was completed early in 1981, increasing its refining capacity to 4 450 from 3 820 cubic metres daily. This was accomplished by increasing the capability of the refinery to process condensate. The plant's fluid catalytic cracking unit was modified late in the year, to enhance environmental protection and improve the octane of the gasoline produced. Connections between the Edmonton refinery and the Alberta Products Pipe Line were completed, permitting the direct delivery by pipeline of petroleum products to the company's new sales terminal in Calgary.

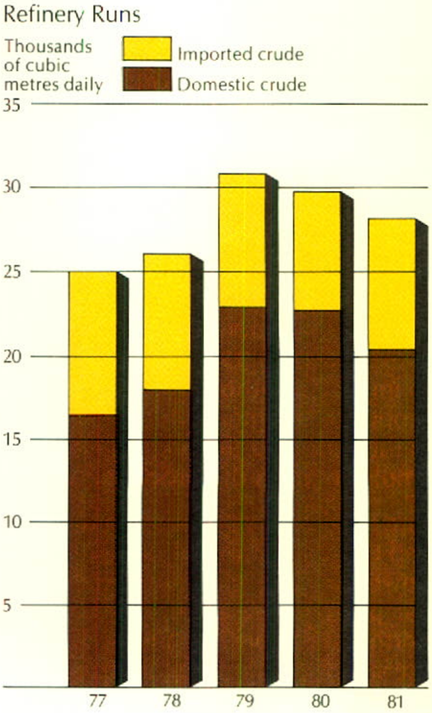
At the Nanticoke refinery, a long-range program to further automate the refinery process instrumentation and control systems was initiated. The first phase of installing the latest computer control and monitoring equipment at this plant is expected to be completed in late 1982. Similar systems are planned for other plants.

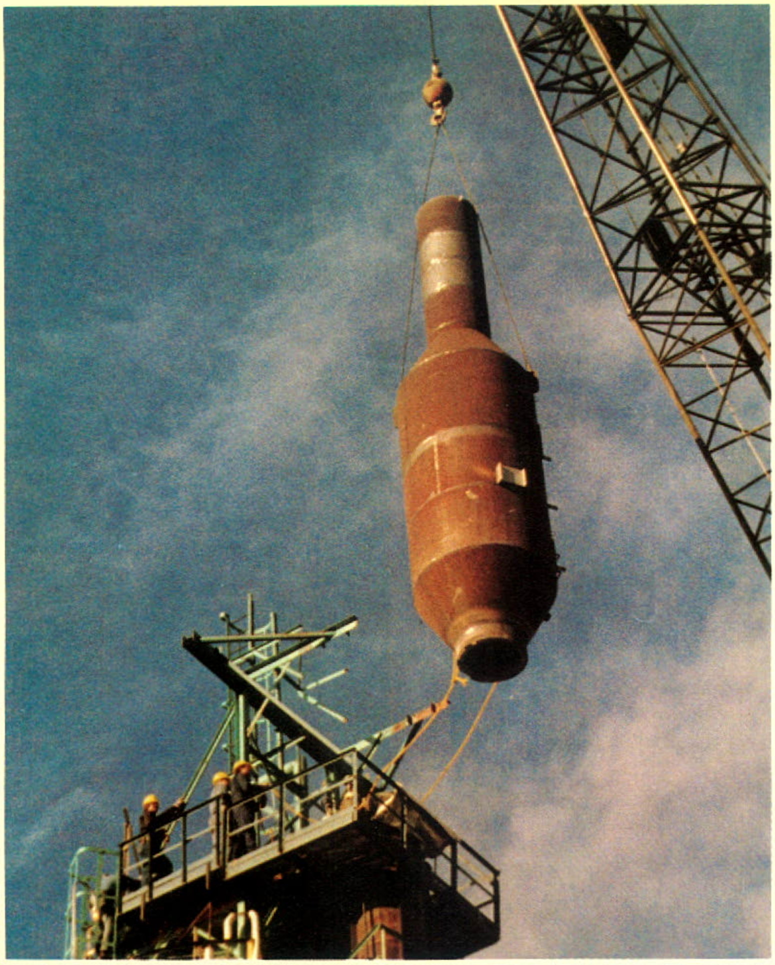
Also at Nanticoke, experimental work in growing vegetables during winter, by using heat not otherwise usable in refining operations, is continuing under the guidance of the University of Guelph. To date three tomato crops have been grown, two of which produced considerably higher yields than normal commercial crops.

Crude runs at the company's plants averaged 28 200 cubic metres daily in 1981, a decline of 5.4 per cent from the level of 29 800 cubic metres daily in the previous year. Refinery utilization was at a rate of 81 per cent in 1981, compared to 88 per cent in 1980.

James Nicholls, Technical Advisor, develops computer program used to further automate instrumentation and control systems at Nanticoke plant.

Refinery Runs





Typical of improvements made during the year to the company's refineries were (left) modifications to Edmonton plant's fluid catalytic cracking unit and (below) installation of above-ground piping to replace existing underground piping at Montreal plant, as part of a continuing environmental protection program.

Marketing

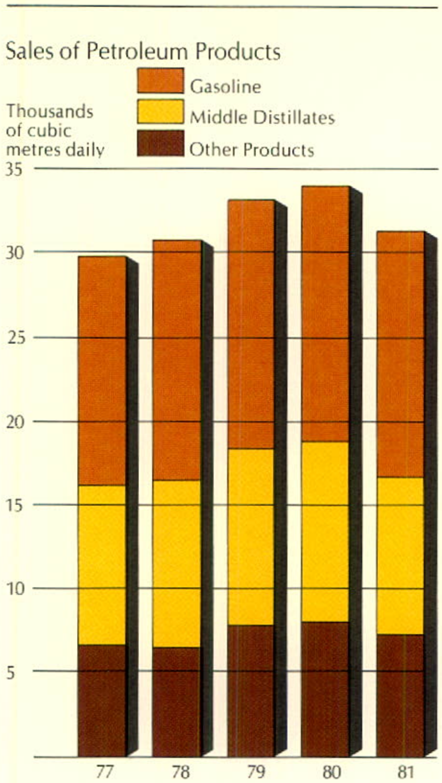
Texaco Canada's sales of petroleum products declined in 1981 as a result of the reduction in consumer demand. Factors contributing to the drop in demand were higher prices—brought about mainly by heavy increases in taxes and charges imposed by federal and provincial Governments—as well as the trend to smaller cars and a slackening in the pace of economic activity.

Canadian demand for petroleum products in 1981 declined by about six per cent from the previous year. This drop reflects a moderate decline in demand for gasoline and a sharp decrease in demand for light and heavy fuel oils, due to a combination of milder than usual weather in the late months of the year and of conservation and conversion to alternate fuels.

During 1981 the federal government imposed special levies on petroleum including a Canadian ownership charge of $1.15 per barrel and other compensation charges of $5.60 a barrel for a total of $6.75 per barrel. These charges were reduced by $1.85 a barrel to $4.90 a barrel, or $30.82 a cubic metre, on November 30. In addition, the federal and provincial sales taxes, most of which are calculated on an ad valorem basis, were increased in 1981.

There was a general surplus of refined products in Canada during most of the year, which resulted in a reduction of profit margins.

The major thrust of the company's marketing program in 1981 was to rationalize all operations with the objective of improving efficiency and reducing costs. Unprofitable wholesale and retail facilities were closed, other units were improved, and new facilities were constructed where needed under this program.



In this connection a number of low volume service stations were closed in 1981 and greater emphasis was placed on upgrading many of the remaining outlets to achieve the sale of a larger volume of products through fewer outlets. Diesel fuel facilities were added to some service stations to serve the growing number of diesel-powered vehicles. The marketing of propane was started in 1981 at selected retail outlets. Propane can be used in vehicles with modified carburetor and fuel storage systems.

The company's new sales terminal at Calgary, which is connected to the Alberta Products Pipe Line system, went into operation in December 1981. This 30-acre terminal serves as the distribution point for tank car and tank truck shipments to southern Alberta and southeastern British Columbia. The tank truck loading facilities will be fully automated in 1982 through a computer which will be linked to the company's Operations Centre in Don Mills, Ontario.

During 1981 the company expanded its fleet of large truck units as part of its program to improve distribution efficiency.

Texaco Canada's sales of petroleum products during 1981 averaged 31 600 cubic metres daily, compared with 33 800 cubic metres daily in 1980. This was a decrease of 6.8 per cent.

Multiple use of retail facilities has increased revenue from several outlets, such as this successful service station-grocery store operation at Sudbury, Ontario.

Tank truck driver instructs valve operator during testing of meters at new Calgary marketing terminal.

Supply and Distribution

The company's supply operations in 1981 involved the transportation of an average of 61 900 cubic metres of crude oil and petroleum products daily, compared with 65 000 cubic metres daily the year before, a decline of about 4.8 per cent. This volume included the movement of 29 800 cubic metres of finished products daily to customers in company-owned and leased vehicles and ships. The balance, consisting principally of crude oil and natural gas liquids used in the company's refining and supply operations, was moved mainly by ocean tankers and pipelines.

As part of its product supply system, the company transported 5 300 cubic metres daily in lake and coastal tankers. Three-quarters of this quantity was moved in company-owned vessels and the balance in vessels chartered by Texaco Canada.

The Alberta Products Pipe Line system, in which Texaco Canada holds a 20 per cent interest, transported a daily average of 9 900 cubic metres of petroleum products, an increase of about two per cent over the previous year.

Trans-Northern Pipelines Inc., one-third owned by Texaco Canada, carried 24 000 cubic metres of petroleum products daily, a decrease of about four per cent compared with 1980.

A daily average of 28 500 cubic metres of imported crude oil was moved over the Montreal Pipe Line system, 16 per cent owned, to refineries in Montreal from its east-coast terminal facilities in Portland, Maine. This was an increase of about 27 per cent over the previous year. The higher volume reflected additional crude oil imported to supply the Montreal refineries as Canadian crude oil supplies continued to decline, as well as the Alberta government's withholding of crude oil during the protracted negotiations prior to the federal-provincial agreement on crude oil pricing announced in September 1981.

Federated Pipe Lines Ltd., 50 per cent owned by Texaco Canada, carried 26 200 cubic metres daily of crude oil from the Swan Hills area of Alberta to Edmonton, a decrease of about 23 per cent from 1980.

The Rimbey-Edmonton Oil Pipeline, 100 per cent owned by Texaco Canada, carried an average of 30 800 cubic metres daily of crude oil and natural gas liquids from central Alberta to Edmonton, about the same volume as in the previous year.

Oil spill training exercise hones skills of employees who would participate in cleanup operations.

The Environment

Capital expenditures for environmental protection facilities exceeded $16 million in 1981. These expenditures and the many manhours devoted to environmental protection efforts underline the strong emphasis which the company continues to place on air and water quality.

Texaco Canada supported and contributed to the development and funding of several multi-million dollar oil spill cleanup cooperatives across Canada. These organizations provide the company with access to specialized equipment and trained personnel to assist its own emergency response teams in combating oil spills if they should occur.

A land farm for biological disposal of sludge and solid wastes at the Nanticoke refinery was completed in 1981. This facility can safely and economically dispose of these plant wastes. A similar facility is in operation at Halifax plant and one is planned for the Montreal refinery.

The installation of new air pollution control equipment at Edmonton plant was completed in 1981, which significantly reduced emissions of carbon monoxide.

As part of its continuing program of environmental improvement and loss control, the company installed floating roofs on a number of gasoline storage tanks at sales terminals. In addition, loading facilities at several sales terminals were upgraded to include bottom loading equipment. These installations minimize vapor emissions, improve efficiency and safety, and reduce the possibility of overloading.

Texaco Canada continues its efforts through the Petroleum Association for Conservation of the Canadian Environment to cooperate with all levels of government in developing practical as well as cost effective environmental regulations.

Employee Relations

Texaco Canada had 4,522 employees at year-end 1981, compared with 4,442 at December 31, 1980. Payroll and benefits plan costs of $146.6 million were 16.2 per cent higher in 1981 than in the previous year.

A new program of Performance Planning and Review workshops across Canada was launched and attended by some 1,800 employees in 1981. This program combines goal planning and reviews of achievements with a view to improving employee effectiveness. The company also held in-house training programs in Management Development and Supervisory Leadership Skills in which 387 employees participated.

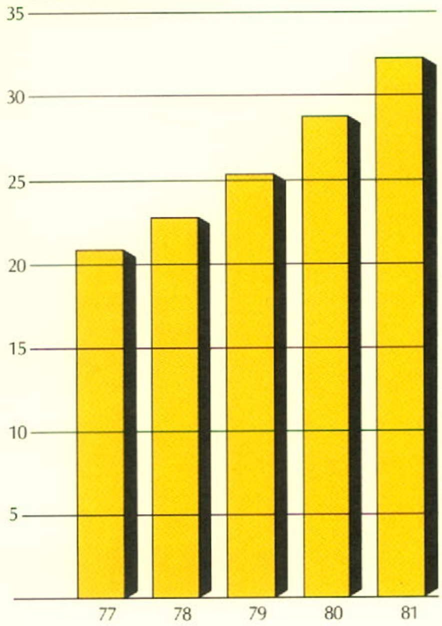
An annual Employee Benefit Plans statement for each employee with a minimum of one year of service was also introduced in 1981. This personalized statement includes details of the employee's coverage in the event of sickness, disability or death, an estimate of projected retirement benefits, and other information of value to employees.

At the end of 1981, 97 students, sons and daughters of employees, were participating in the Texaco Canada Merit Scholarship program. The scholarships cover the cost of tuition and compulsory fees at Canadian universities or colleges of the recipient's choice for up to four years. The company also offers assistance to employees to advance their education and skills through a tuition aid plan which usually covers 75 per cent of tuition for approved courses.

Seventy-four employees received the 25-year Service Award in 1981. At year-end, Texaco Canada had 743 employees with 25 or more years of service.

Fifty-five employees retired in 1981 under the company's retirement plans.

Salaries, Wages and Benefits per Employee
Thousands of dollars



Public Affairs

During the year Texaco Canada increased and improved its communications with its principal publics—including employees, governments, shareholders, customers and consumers—and stated its views on energy and other policies which impact upon the company and the petroleum industry.

The company also increased its support to deserving organizations across Canada in the fields of education, community service, health, culture and youth work.

Through representations to governments, press releases, speeches and discussions by executives, media interviews, articles in company publications and mailings to customers and shareholders, Texaco Canada stated its positions on key energy questions and provided information on its activities and progress. Particular emphasis was given to communicating the company's views concerning the National Energy Program, the federal-provincial energy pricing and taxation agreements, and the Bertrand Report on the state of competition in the Canadian petroleum industry.

These and other important matters were discussed with hundreds of company employees at locations across the country as part of the company's Speakers' Program of two-way discussions with employees, dealers and the general public. This program will be expanded in 1982 to reach more external audiences.

The company also began in 1981 its 42nd consecutive year of sponsoring Metropolitan Opera radio broadcasts. These programs are carried across Canada on the English and French language networks of the Canadian Broadcasting Corporation.

Financial Review of 1981

NET INCOME

Texaco Canada's consolidated net income in 1981 was $316.3 million, compared with $373.4 million in 1980 and $263.9 million in 1979. The reduction in net income in 1981, which reverses the trend of improved earnings for the years 1980 and 1979, is due mainly to the Federal Petroleum and Gas Revenue Tax which became effective January 1, 1981. This tax, which is not deductible for income tax purposes amounted to $71.5 million and was only partially offset by higher prices for crude oil, natural gas liquids and refined products. In addition, government restrictions placed on the production of crude oil, lower volumes of petroleum product sales and higher costs contributed to lower earnings.

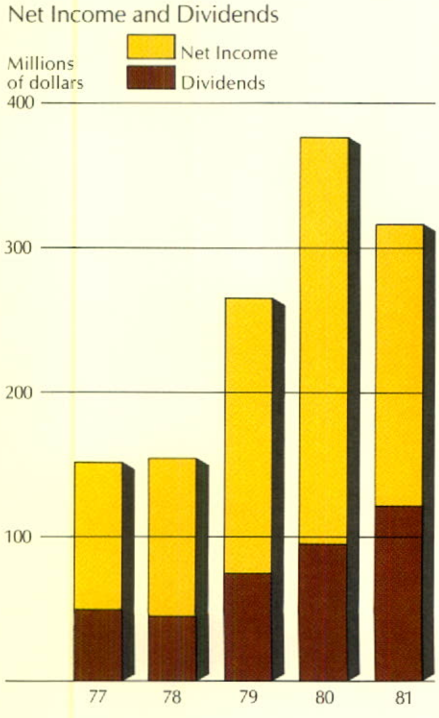
Net income for 1981 includes non-recurring inventory net profits, arising from the implementation of rate changes in the federal petroleum compensation charge. The effect of these changes resulted in increased net income in 1981 of approximately $33.0 million, or $0.27 a common share.

Net income for 1980 includes a non-recurring profit of $31.1 million, or $0.26 per common share, resulting from a change in the handling of the company's production of oil from Crown lands in Alberta. This change occurred on April 1, 1980, when the Alberta Petroleum Marketing Commission assumed control of all Crown oil production in the province. Previously, profits on such oil were not recognized until the products made from the crude oil were finally sold.

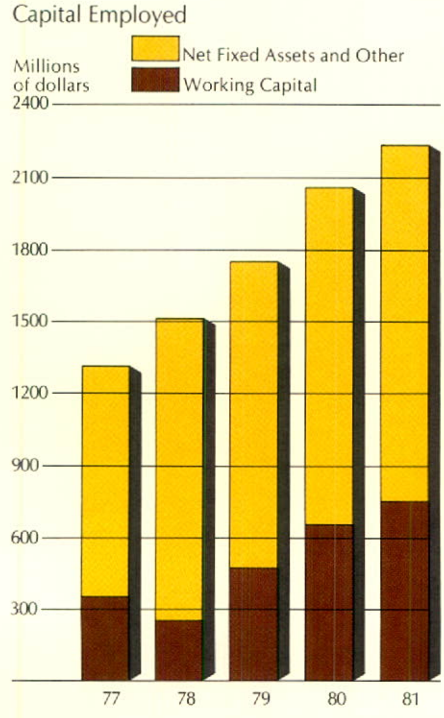
Net income per common share in 1981 was $2.45, compared with $2.92 in 1980 and $2.01 in 1979. The company's common shares were split on a four-for-one basis effective August 15, 1980, and all references to earnings per share for the period prior to 1980, including the above, reflect adjustment for this split.

Gross production of crude oil and natural gas liquids for 1981 averaged 23 500 cubic metres daily, compared with 24 000 cubic metres in 1980 and 26 700 cubic metres in 1979; crude oil processed in the company's refineries averaged 28 200 cubic metres daily in 1981, 29 800 cubic metres in 1980 and 30 800 cubic metres in 1979; sales of petroleum products were 31 600 cubic metres daily in 1981, 33 800 cubic metres in 1980 and 32 900 cubic metres in 1979. Sales of natural gas in 1981 amounted to 3.3 million cubic metres daily, compared with 2.4 million cubic metres and 2.2 million cubic metres in 1980 and 1979 respectively.

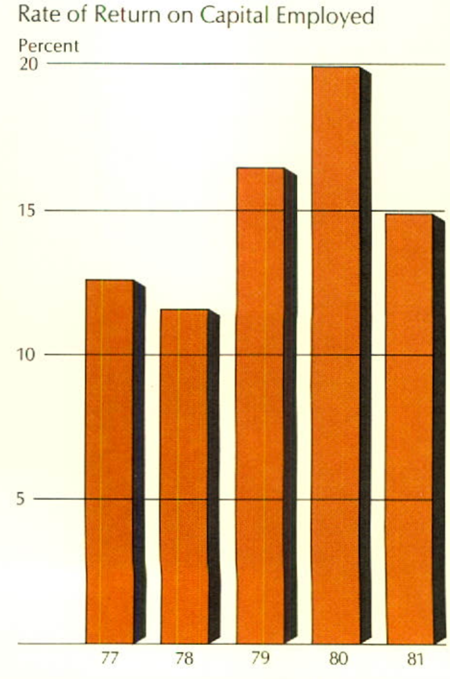
Net Income and Dividends



Capital Employed



Rate of Return on Capital Employed



DIVIDEND PAYMENTS

Texaco Canada's Board of Directors has declared dividends on the company's common shares in every year since 1944. From 1944 through 1951 dividends were on an annual or semi-annual basis. Since 1952 they have been declared and paid on a quarterly basis.

The total amount of dividends paid per common share in each of the last three years was 82 cents in 1981, 58½ cents in 1980 and 42 cents in 1979. These dividends as a percentage of net income per common share were 33 per cent in 1981, 20 per cent in 1980, and 21 per cent in 1979.

STOCK MARKET AND DIVIDEND INFORMATION

Texaco Canada's common shares continue to be listed on the Toronto, Montreal, Alberta, Vancouver and American Stock Exchanges. The Toronto Stock Exchange is the principal market for the shares. Quarterly high and low prices and the dividends paid on the common shares are as follows:

	1981		
	*Price Range		Dividends
	High	Low	Paid
Quarter			
1st	$25¾	$22	$0.190
2nd	39¼	23¾	.190
3rd	45	21½	.190
4th	38½	28½	.250

	1980		
	*Price Range		Dividends
	High	Low	Paid
Quarter			
1st	$24	$19	$0.125
2nd	26½	19¼	.125
3rd	32¾	21½	.145
4th	27¼	20¼	.190

*As quoted on the Toronto Stock Exchange. Price ranges in the First and Second Quarters of 1980, have been adjusted to approximate fractional values of quotations made prior to the 4:1 stock split on August 15, 1980.

On January 31, 1982, there were 5,360 individual, financial and other institutional holders of the company's common shares. This compares with a total on December 31 of 5,366 in 1981, 5,592 in 1980 and 4,038 in 1979.

Dividends paid to United States security holders are subject to a 15 per cent Canadian withholding tax in accordance with the Canada—United States Income Tax Treaty currently in force. Capital gains on disposals are not taxable in Canada if the United States security holder has no permanent establishment in Canada.

A proposed Canada—United States Income Tax Treaty, signed on September 26, 1980, but not yet ratified, generally preserves the existing taxation and withholding rules as they relate to United States security holders. One exception is that corporate holders of at least 10 per cent of voting shares will incur only a 10 per cent withholding tax on dividends.

REVENUES

Revenues in 1981 totalled $4,461.0 million, compared with $3,572.0 million in 1980 and $2,684.9 million in 1979. The increase in total revenue resulted from the higher prices at which petroleum products were sold to recover the higher cost of crude oil as determined under the federal government's oil pricing policies.

As a result of the imposition of various federal petroleum compensation charges during 1981 the cost of a cubic metre of crude oil increased by $30.82. In addition the January 1, July 1 and October 1 crude oil price increases amounted to a total of $28.31 per cubic metre. Refined product sales volumes were lower in 1981 due mainly to reduced consumer demand, particularly in the second half of 1981.

COSTS AND OPERATING EXPENSES

Costs and operating expenses, including selling, general and administrative expenses, amounted to $3,360.1 million in 1981, compared with $2,597.8 million in 1980 and $1,948.7 million in 1979.

Factors which contributed to increased costs included higher prices paid for supplies of crude oil, other raw material, and labour, as well as the continuing effects of general inflation.

Costs and operating expenses were equivalent to 75.3 per cent of total revenue in 1981, compared with 72.7 per cent in 1980 and 72.6 per cent in 1979. Selling, general and administrative expenses, as a proportion of costs and operating expenses, decreased from 6.4 per cent in 1979, to 5.1 per cent in 1980 and 4.5 per cent in 1981.

OTHER EXPENSES

Dry hole costs in 1981 amounted to $31.4 million, an increase of $22.1 million compared to 1980 and an increase of $19.1 million over 1979.

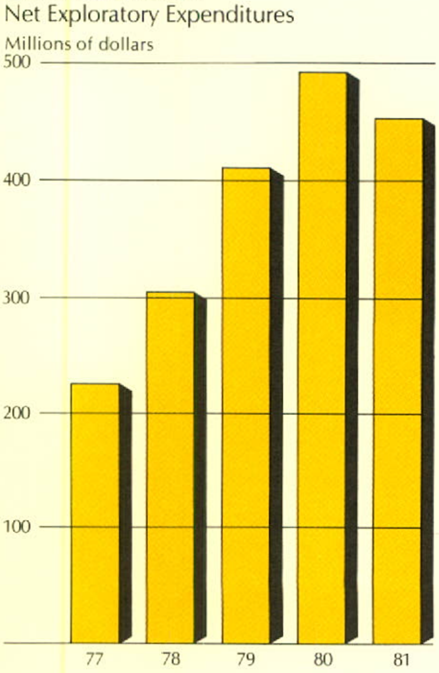
Depreciation, depletion and amortization charges were $63.7 million in 1981, an increase of $9.0 million over 1979. Interest expense, which amounted to $10.0 million in 1981, increased 14.7 per cent since 1979.

TAXES

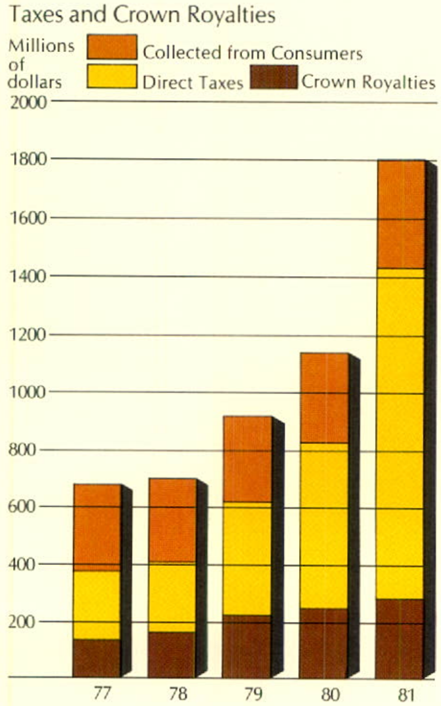
Taxes paid or accrued by Texaco Canada, including direct taxes and taxes collected from consumers on behalf of governments, totalled $1,801.1 million in 1981, $1,141.1 million in 1980, and $919.9 million in 1979.

The aggregate amount of these taxes in 1981 was equivalent to about six times the net income of the company and approximately 15 times the amount that shareholders of preferred and common stock received as dividends in that year.

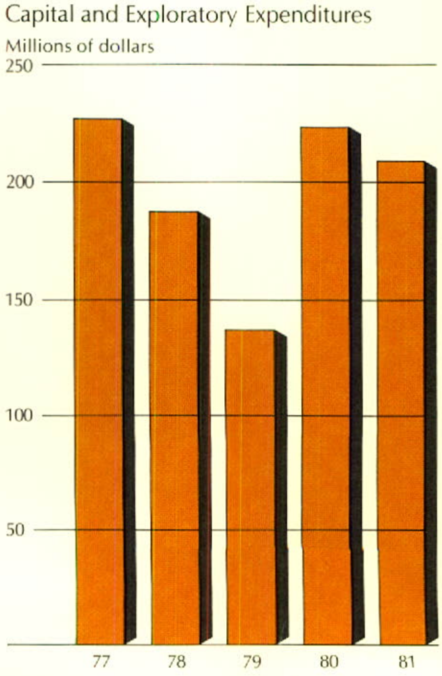
Funds Provided by Operations before deduction of Net Exploratory Expenditures



Taxes and Crown Royalties



Capital and Exploratory Expenditures



Direct taxes include oil and gas production taxes, sales and use taxes, property taxes, import duties and other levies, and current and deferred income taxes. The company's current and deferred income taxes continued to rise following the trend of improvement in operating earnings before deduction of the federal Petroleum and Gas Revenue Tax. Total income taxes increased from $256.2 million in 1979 to $340.7 million in 1980 and $369.6 million in 1981. The effective income tax rate has increased from 49.3 per cent in 1979 to 53.9 per cent in 1981. The federal Petroleum and Gas Revenue Tax effective January 1, 1981 amounted to $71.5 million, and was a major contributor to the increase in 1981 expenses. All other direct taxes increased from $366.6 million in 1979 to $482.6 million in 1980 and $988.2 million in 1981.

Taxes collected from consumers include federal sales and excise taxes and provincial motor fuel and oil taxes. These taxes rose from $297.1 million in 1979 to $317.8 million in 1980 and $371.8 million in 1981, an increase from 1979 through 1981 of 25.0 per cent. These increases resulted from the imposition by the federal and most provincial governments of motor fuel taxes on an ad valorem basis. This new basis establishes motor fuel tax as a percentage of net selling price rather than as a fixed amount per volume. Previously the level of such taxes could be changed only by new legislation.

LIQUIDITY AND CAPITAL RESOURCES

The company's liquidity position continues strong, as evidenced by the level of working capital, the current ratio, and other generally applied balance sheet and cash flow ratios. Current levels of working capital provide adequately for the company's ongoing operations.

In addition to the company's strong year-end 1981 cash and short-term investment position, Texaco's liquidity is further enhanced by the nature of its accounts receivable and merchandise inventories. Rapid turnover of accounts receivable backed by sound credit and collection policies make these receivables highly liquid. The company's inventories, made up of crude oil and petroleum products, are readily convertible to cash.

The company has ample capacity to maintain liquidity and provide capital resources by virtue of its capacity to borrow. Also, the company regularly maintains substantial bank lines of credit.

The company's strong earnings performance over the last three years has given it the availability of funds necessary to support planned capital investments.

ASSETS

Total assets of the company at the end of 1981 were $2,879.1 million, compared with $2,603.1 million at the end of 1980 and $2,299.7 million as at December 31, 1979.

CAPITAL AND EXPLORATORY EXPENDITURES

The company's total capital and exploratory expenditures amounted to $209.3 million in 1981, compared with $224.2 million in 1980 and $136.6 million in 1979. Capital and exploratory expenditures in 1981 were slightly lower than 1980 levels due to the combined effects of the National Energy Program, and the federal/provincial pricing agreements, which reduced cash flow available to the industry for expansion in that year.

Capital and Exploratory Expenditures

	Millions of Dollars		
	1981	1980	1979
Energy Resources	**$140.5**	$178.3	$ 89.9
Manufacturing	**33.7**	21.6	25.4
Marketing	**31.1**	21.7	19.6
Other	**4.0**	2.6	1.7
Total capital and exploratory expenditures	**209.3**	224.2	136.6
Deduct: Exploratory expenditures charged against current income	**49.5**	31.4	26.1
Total expenditures capitalized	**$159.8**	$192.8	$110.5

Index to Financial Section

Description of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts of Texaco Canada Inc. and its subsidiary companies and are prepared in accordance with accounting principles generally accepted in Canada. The financial statements also conform with International Accounting Standards in all material respects. Intercompany accounts and transactions are eliminated.

The premium paid on subsidiary companies' capital stock at date of acquisition is amortized on a straight-line basis over 20 years.

Foreign currencies are translated into Canadian dollars as follows: (1) Current assets except inventories, long-term receivables, current liabilities, and capital lease obligations, at the rate in effect at the end of the period; (2) inventories, properties, plant and equipment and related depreciation and deferred charges at rates in effect when the assets were acquired; and (3) all other income accounts at rates in effect at the time of the transaction. Gains and losses on foreign currency transactions and charges and credits arising on translation of balance sheet accounts are reflected in income currently.

Inventories

Inventories of crude oil and petroleum products and other merchandise are stated at the lower of cost, determined on the first-in, first-out method, and net realizable value. Materials and supplies are stated at cost.

Investments and Advances

The Corporation uses the equity method of accounting for its investments in companies owned 50%, and for all significant corporate joint ventures owned less than 50%. Under this method, the Corporation's equity in net earnings or losses of these companies is reflected currently in income rather than when realized through dividends. Investments in companies accounted for by this method reflect the Corporation's equity in the underlying net assets of the companies.

Investments in other non-subsidiary companies are carried at cost, and the Corporation's interest in the net earnings of these companies is reflected in income when realized through dividends.

The Corporation has equipment leased to an affiliated company. These non-mineral leases are capitalized as direct financing leases and amortized in accordance with the respective lease agreement.

Properties, Plant and Equipment and Accumulated Depreciation, Depletion, and Amortization

The Corporation follows the successful efforts method of accounting for its oil, gas exploration and producing operations. Under this method all exploratory costs, including geophysical and geological expenses, core drilling, lease rentals and intangible drilling costs applicable to dry holes, are charged to expense.

Lease acquisition costs, intangible drilling costs on productive wells and tangible equipment costs related to the development of oil and gas reserves are capitalized and amortized. For lease acquisitions costing less than one million dollars, the portion of leasehold costs estimated to be non-productive based upon historical experience is amortized on an average holding period basis. For lease acquisitions costing one million dollars or more, the portion of leasehold costs estimated to be non-productive is amortized over the initial exploration period. Leasehold costs which have been determined to be productive and other development costs related to producing activities, including tangible and intangible costs, are amortized on the unit-of-production basis by applying the ratio of produced oil and gas to estimated recoverable oil and gas reserves.

Depreciation of other properties, plant and equipment is provided generally on the group plan, using the straight-line method, with depreciation rates based upon estimated useful life applied to the cost of each class of property.

Start-up costs of new facilities are capitalized and amortized in accordance with the Corporation's depreciation policy.

The Corporation accounts for significant leases, other than exploration and development of natural resource rights, that transfer all of the benefits and risks of ownership related to leased properties as capital leases. Properties, plant and equipment include capital leases which are amortized over the estimated useful life of the asset or lease term, as appropriate, using the straight-line method.

Normal maintenance and repairs are charged to expense as incurred. Renewals, betterments, and major repairs that materially extend the life of properties are capitalized and the assets replaced, if any, are retired.

Research and Development Costs

Research costs are charged to income as incurred. Development costs are charged as an expense of the period in which they are incurred except when the project is expected to commence commercial production within the foreseeable future. When this occurs, development costs are deferred and amortized to match related revenues.

Deferred Income Taxes

Provision is made in the Corporation's accounts to reflect the income tax effect on transactions recorded in the Corporation's financial statements in a reporting period different from the period in which they are reported for income tax purposes. The principal transactions are depreciation, intangible drilling costs, leasehold costs and inventories.

Deferred income taxes as shown in the balance sheet represent the cumulative effect of net charges made against earnings to defer these income tax effects to appropriate future periods in the Corporation's financial statements. This accounting policy allocates the income tax effect of transactions to the period in which such transactions are recorded for financial reporting purposes.

Pension Plan

A group pension plan is available to substantially all employees. Amounts charged to pension expense are based on amortizing the cost of pension benefits on an actuarial basis over the remaining estimated service of the employees involved.

Investment Tax Credits

Investment tax credits, other than tax rate reductions, are deducted from the related expenditure and amortized to income in accordance with the applicable accounting policy.

Federal Government Crude Oil Compensation Programs

Compensation received or recoverable under the programs for imported and for synthetic domestic oil for consumption in Canada is deducted from cost of crude oil purchases. In order to be eligible for compensation the Corporation has complied with Federal Government legislation.

Consolidated Statement of Income

for the years ended December 31, 1981, 1980 and 1979 (Expressed in thousands of Canadian dollars except per share data)

	1981	1980	1979
Revenues			
Sales and services			
Texaco Inc. and its subsidiary companies	**$ 22,890**	$ 23,791	$ 15,695
Other	**4,352,442**	3,479,388	2,622,928
Income from investments			
Equity in net income of non-subsidiary companies (Note 3)	**4,664**	3,865	4,003
Dividends and interest	**58,647**	38,901	18,996
Interest income—Texaco Inc. and its subsidiary companies	**15,236**	16,833	15,883
Other income	**7,100**	9,238	7,377
	$4,460,979	$3,572,016	$2,684,882
Deductions			
Cost of sales and operating expenses (Note 2)			
Purchase of crude oil and products from Texaco Inc. and its subsidiary companies	**$ 527,943**	$ 398,537	$ 434,247
* Other	**2,681,720**	2,065,605	1,389,196
Selling, general and administrative expenses	**150,474**	133,694	125,207
Maintenance and repairs	**58,098**	51,285	41,548
Dry hole costs	**31,390**	9,273	12,245
Depreciation, depletion, and amortization	**63,685**	56,404	54,719
Interest charges (Note 12)	**10,021**	11,227	8,735
Petroleum and gas revenue tax	**71,478**	—	—
Taxes, other than income taxes (Note 10)	**180,262**	131,883	98,917
	$3,775,071	$2,857,908	$2,164,814
Income before Provision for Income Taxes	**$ 685,908**	$ 714,108	$ 520,068
Provision for Income Taxes (Note 13)			
Current income taxes			
Federal	**$ 278,788**	$ 237,028	$ 164,589
Provincial	**69,011**	57,269	43,311
Deferred income taxes	**21,803**	46,393	48,273
	$ 369,602	$ 340,690	$ 256,173
Net Income	**$ 316,306**	$ 373,418	$ 263,895
**Net income per common share	**$2.45**	$2.92	$2.01

Certain accounts have been reclassified to conform with the 1981 presentation. The reclassification had no effect on net income.

*In accordance with the Corporation's accounting policy, inventories of crude oil and petroleum products are stated at cost, determined on the first-in, first-out method. Effective April 1, 1980, the Alberta Petroleum Marketing Commission took effective control of all oil produced from Crown properties in the Province of Alberta. Commencing on this date, the Corporation valued its inventories of oil produced from Crown property in the Province of Alberta at the price paid to the Alberta Petroleum Marketing Commission, whereas in prior periods, related inventories were stated at the Corporation's cost of producing the product. This action resulted in an increase in income for the 1980 period of $31,081 equal to $0.26 per common share.

**Net income per common share is based on the average number of common shares outstanding after adjusting for the four-for-one split which occurred on August 15, 1980 (1981—120,632,882 shares, 1980—120,546,211 shares, 1979—120,500,128 shares). Conversion of the First Preferred Shares, Series A, into common shares would not materially change the net income per common share.

See accompanying description of significant accounting policies and notes to consolidated financial statements.

Consolidated Statement of Retained Earnings

for the years ended December 31, 1981, 1980 and 1979 (Expressed in thousands of Canadian dollars except per share data)

	1981	1980	1979
Balance at beginning of year	**$1,245,562**	$ 964,278	$772,639
Add—			
Net income for the year	**316,306**	373,418	263,895
Deduct—			
Dividends declared			
Preferred stock	**20,577**	21,614	21,645
Common stock	**98,920**	70,520	50,611
Balance at end of year	**$1,442,371**	$1,245,562	$964,278
Cash dividends per share			
First Preferred, Series A	**$6.00**	$6.00	$6.00
Second Preferred, Series A	**7.50**	7.50	7.50
Second Preferred, Series B	**7.25**	7.25	7.25
Common	**0.82**	0.585	0.42

See accompanying description of significant accounting policies and notes to consolidated financial statements.

Consolidated Balance Sheet

December 31, 1981 and 1980 (Expressed in thousands of Canadian dollars)

Assets	1981	1980
Current Assets		
Cash	$ 11,087	$ 11,225
Marketable securities (at cost which approximates market value)	273,208	323,919
Notes and accounts receivable (less allowance for doubtful accounts of $4,500 in 1981, and $3,500 in 1980)		
Affiliated companies	–	9,463
Other	501,195	443,618
Inventories (Note 2)	583,025	382,147
Prepaid expenses and deferred income taxes	28,230	28,054
Total current assets	$1,396,745	$1,198,426
Investments and Advances (Note 3)	$ 183,608	$ 190,909
Properties, Plant and Equipment (Notes 4 and 8)	$1,279,646	$1,203,318
Deferred Charges	$ 19,064	$ 10,448
Total	$2,879,063	$2,603,101

Texaco Canada follows the "successful efforts method" of accounting for its oil and gas exploration and producing operations as outlined in the description of significant accounting policies.

Certain balance sheet accounts have been reclassified to conform with the 1981 presentation.

See accompanying description of significant accounting policies and notes to consolidated financial statements.

Liabilities and Shareholders' Equity

Liabilities and Shareholders' Equity	1981	1980
Current Liabilities		
Long-term debt due within one year	$ 32	$ 30
Capital lease obligations due within one year	2,661	6,593
Accounts payable		
Trade	266,856	239,024
Affiliated companies	32,127	–
Accrued liabilities		
Taxes, other than income taxes	102,697	54,328
Other	100,309	70,294
Income taxes	133,754	164,887
Preferred dividends payable	1,566	1,825
Total current liabilities	$ 640,002	$ 536,981
Long-term Debt (Note 5)	$ 75,011	$ 84,601
Capital Lease Obligations (Note 8)	$ 10,623	$ 13,436
Deferred Gas Production Revenue	$ 16,255	$ 11,111
Deferred Income Taxes	$ 407,686	$ 384,295
Redeemable Preferred Stock (Note 6)	$ 250,000	$ 290,000
Preferred Stock (Note 7)	$ 1,120	$ 2,520
Common Stock and Retained Earnings		
Common stock (Note 7)	$ 35,995	$ 34,595
Retained earnings	1,442,371	1,245,562
Total common stock and retained earnings	$1,478,366	$1,280,157
Total	$2,879,063	$2,603,101

Approved on behalf of the Board

Roland M. Reuther, Director

A. M. Head, Director

Consolidated Statement of Changes in Financial Position

for the years ended December 31, 1981, 1980 and 1979 (Expressed in thousands of Canadian dollars)

	1981	1980	1979
Source			
Net income	**$316,306**	$373,418	$263,895
Depreciation, depletion, and amortization	**63,685**	56,404	54,719
Provision for income taxes—deferred	**23,391**	34,874	64,869
Excess of equity in net income of non-subsidiary companies over dividends (Note 3)	**(133)**	(363)	(780)
Unrealized net currency translation loss (gain) on long-term receivables and capital lease obligations	**1,249**	(3,575)	3,931
Provided by operations	**$404,498**	$460,758	$386,634
Investments and advances (net)	**6,132**	2,089	8,792
Properties, plant and equipment retirements, sales, and investment tax credits	**19,753**	14,196	30,656
Other net source (disposition)	**(3,472)**	3,943	2,767
	$426,911	$480,986	$428,849
Disposition			
*Properties, plant and equipment expenditures	**$159,766**	$192,764	$110,547
Redemption of 400,000 Second Preferred Shares—Series B, at $100.00 per share	**40,000**	–	–
Reduction in long-term debt (Note 5)	**9,590**	9,247	6,247
Net reduction in capital lease obligation (Note 8)	**2,760**	3,021	13,944
Cash dividends—preferred stock	**20,577**	21,614	21,645
—common stock	**98,920**	70,520	50,611
	$331,613	$297,166	$202,994
Increase in working capital	**$ 95,298**	$183,820	$225,855

*Properties, plant and equipment expenditures			
Producing	**$ 90,971**	$146,874	$ 63,898
Manufacturing	**33,717**	21,622	25,382
Marketing	**31,078**	21,692	19,635
Marine	**326**	225	289
Pipelines	**231**	312	223
Other	**3,443**	2,039	1,120
Total	**$159,766**	$192,764	$110,547

See accompanying description of significant accounting policies and notes to consolidated financial statements.

	1981	1980	1979
Working Capital			
At beginning of year	**$661,445**	$477,625	$251,770
Increase (decrease) during year			
Cash	**$ (138)**	$ (1,057)	$ (17,378)
Marketable securities (at cost)	**(50,711)**	43,172	269,540
Notes and accounts receivable, less allowance for doubtful accounts			
Affiliated companies	**(9,463)**	9,463	–
Other	**57,577**	40,222	150,875
Inventories	**200,878**	100,541	91,977
Prepaid expenses and deferred income taxes	**176**	(20,528)	29,679
Long-term debt due within one year	**(2)**	(2)	(2)
Capital lease obligations due within one year	**3,932**	1,364	3,658
Accounts payable			
Trade	**(27,832)**	(5,678)	(100,581)
Affiliated companies	**(32,127)**	36,893	(16,836)
Accrued liabilities	**(78,384)**	(38,072)	(12,881)
Income taxes	**31,133**	17,495	(172,207)
Preferred dividends payable	**259**	7	11
	$ 95,298	$183,820	$225,855
At end of year	**$756,743**	$661,445	$477,625

Notes to Consolidated Financial Statements

(Expressed in thousands of Canadian dollars)

1. Accounting Principles Generally Accepted In Canada Compared With the United States

As stated in the Description of Significant Accounting Policies, the consolidated financial statements are prepared in accordance with accounting principles generally accepted in Canada, which principles do not materially differ from generally accepted accounting principles as established in the United States.

2. Inventories

	December 31, 1981	December 31, 1980
Crude oil	**$160,819**	$120,588
Petroleum products and other merchandise	**406,646**	247,649
	567,465	368,237
Materials and supplies	**15,560**	13,910
Total	**$583,025**	$382,147

Amounts of crude oil, petroleum products and other merchandise used to determine cost of sales were as follows: December 31, 1979—$272,853, January 1, 1979—$182,550.

The aggregate of merchandise items as distinguished from refined and in process oil products is not significant.

3. Investments and Advances

	December 31, 1981	December 31, 1980
Non-subsidiary companies accounted for:		
On equity basis	**$ 18,761**	$ 18,627
At cost	**1,116**	937
	19,877	19,564
Miscellaneous investments		
Direct financing leases—affiliated company	**154,363**	162,656
Notes, mortgages and other long-term receivables	**9,368**	8,689
Total	**$183,608**	$190,909

Texaco Canada Inc.'s equity in the net income of the non-subsidiary companies accounted for on the equity method aggregated $4,664 in 1981, $3,865 in 1980, and $4,003 in 1979. Dividends received from companies accounted for by this method amounted to $4,531 in 1981, and $3,502 in 1980, and $3,223 in 1979. Undistributed earnings of these non-subsidiary companies included in Texaco Canada Inc.'s retained earnings amounted to $16,285 at December 31, 1981 and $16,152 at December 31, 1980.

4. Properties, Plant and Equipment

As at December 31,	Cost 1981	Cost 1980	Accumulated depreciation, depletion, and amortization 1981	Accumulated depreciation, depletion, and amortization 1980
Producing	**$ 711,599**	$ 629,743	**$ 224,170**	$ 198,025
Manufacturing	**721,868**	691,056	**150,645**	131,545
Marketing	**316,280**	305,596	**127,527**	124,333
Marine	**20,753**	20,434	**4,896**	4,173
Pipelines	**11,081**	10,910	**5,818**	5,614
Other	**19,233**	16,354	**8,112**	7,085
Total	**$1,800,814**	$1,674,093	**$ 521,168**	$ 470,775
Net investment	**$1,279,646**	$1,203,318		

On November 30, 1978, the Corporation announced that it had substantially reduced operations at its Port Credit refinery. However, the facility continues to serve as the Corporation's main product distribution point for the Toronto, Ontario area and for the production of petrochemicals. As at December 31, 1981, the undepreciated investment in the inactive segment of the Port Credit location is not significant.

5. Long-term Debt

The Corporation had long-term debt as follows:

	December 31, 1981	December 31, 1980
10¾% debentures, 1974 series, due 1994 ($5,000 annual sinking fund requirement 1982–1993)	**$90,000**	$95,000
Other	**37**	67
	90,037	95,067
Less: Long-term debt due within one year and debentures held for sinking fund requirements (1981–$9,994, and 1980–$5,436)	**15,026**	10,466
Total	**$75,011**	$84,601

Annual maturities of long-term debt, including sinking fund payments and other redemption requirements, for the five years subsequent to December 31, 1981, are as follows: 1982–$5,032, 1983–$5,005, 1984–$5,000, 1985–$5,000, and 1986–$5,000.

6. Redeemable Preferred Stock

	December 31, 1981	December 31, 1980
Second Preferred Shares		
2,900,000 shares without nominal or par value, authorized and issuable in series:		
Series A–$7.50 cumulative, redeemable		
Issued and Outstanding–1,700,000 shares	**$170,000**	$170,000
Series B–$7.25 cumulative, redeemable		
Issued and Outstanding–1981, 800,000 shares and 1980, 1,200,000 shares	**80,000**	120,000
Total	**$250,000**	$290,000

Notes to Consolidated Financial Statements (Continued)

(Expressed in thousands of Canadian dollars)

Second Preferred Shares, Series A, are redeemable at $100.00 a share on the last day of February, May, August and November in each twelve-month period after June 1, 1984. The Corporation shall not call for redemption, redeem, purchase or otherwise retire for value any Second Preferred Shares, Series A, at any time when any Second Preferred Shares, Series B, are outstanding unless contemporaneously therewith it shall call for redemption and redeem, purchase or otherwise acquire all outstanding Second Preferred Shares, Series B. At the option of the holders, 400,000 shares may be redeemed each twelve-month period from June 1, 1984 through 1986 and 500,000 shares each twelve-month period thereafter. If certain dividend and working capital tests are met, the number of shares which may be redeemed at the option of the holders can be increased to 800,000 each twelve-month period from June 1, 1984 through 1986 and to 900,000 each twelve-month period thereafter.

Second Preferred Shares, Series B, are redeemable at $100.00 a share. There is a mandatory redemption on the last day of February and May commencing in 1982 and each year thereafter for a total of 400,000 shares each year. Subject to certain dividend and working capital tests being met, redemption may be accelerated at the option of the holders for an additional 400,000 shares after June 1, 1981 and each twelve-month period thereafter. In August 1981, the Corporation redeemed for cash consideration 400,000 Second Preferred Shares, Series B, at a redemption price of $100.00 per share.

The Corporation shall not solely at its own option redeem or purchase any Second Preferred Shares on or before June 1, 1988.

7. Capital Stock

	December 31, 1981	December 31, 1980
Preferred Stock		
First Preferred Shares		
Unlimited number of shares without nominal or par value, authorized and issuable in series:		
Series A—$6.00 cumulative, redeemable, convertible		
Issued —37,500 shares		
Outstanding—1981, 11,197 shares, and 1980, 25,198 shares	**$ 1,120**	$ 2,520
Common Stock		
Common Shares		
Unlimited number of shares without nominal or par value and authorized:		
Issued and outstanding—1981, 120,680,872 shares, and 1980, 120,568,864 shares	**$35,995**	$34,595

First Preferred Shares, Series A, are redeemable at the Corporation's option upon a notice of not less than thirty days prior to the date fixed for redemption for an amount of $102.50 a share or can be purchased by the Corporation at a price not exceeding the redemption price of $102.50. The First Preferred Shares, Series A, will not be redeemed or purchased by the Corporation before the first day of June 1983. These shares are convertible into fully paid and non-assessable Common Shares on the basis of eight Common Shares for each First Preferred Share. During 1981, 14,001 First Preferred Shares, Series A, were converted into 112,008 Common Shares.

During each of the three years ended December 31, 1981, 1980, and 1979, the following changes were reflected in the shares of First Preferred Stock, Series A, and in the shares of Common Stock of Texaco Canada Inc. (in number of shares).

	1981	1980	1979
First Preferred Stock, Series A			
Outstanding at beginning of year	**25,198**	29,736	36,840
Deduct:			
Conversion of First Preferred Shares into Common Shares	**14,001**	4,538	7,104
Outstanding at end of year	**11,197**	25,198	29,736
Common Stock			
Outstanding at beginning of year	**120,568,864**	120,532,560	120,475,728
Add:			
Conversion of First Preferred Shares into Common Shares	**112,008**	36,304	56,832
Outstanding at end of year	**120,680,872**	120,568,864	120,532,560

As approved by the Shareholders on July 25, 1980, the Common Shares were split four-for-one on August 15, 1980. Prior periods and the above descriptions have been restated accordingly.

8. Lease Commitments

As at December 31, 1981, the Corporation had non-cancellable leases expiring more than one year from such date covering service stations, office buildings and other facilities. Capital leases are recorded in the Corporation's balance sheet as assets along with the related debt. The remaining lease obligations are considered to be operating leases and continue to be recorded in the Corporation's income account as rental expense. Minimum amounts payable under capital and operating leases without reduction for related rental income are expected to average approximately $9,196 annually for the next five years.

Leased capital assets included in Properties, Plant and Equipment were as follows:

	December 31,	
	1981	1980
Land	**$ 9,620**	$ 9,723
Buildings and Equipment	**24,820**	32,258
	34,440	41,981
Less: Accumulated amortization	**19,592**	21,257
Total	**$14,848**	$20,724

Future minimum lease payments for capital leases together with the present value of net minimum lease payments on December 31, 1981 are:

1982	$ 3,690
1983	3,184
1984	2,605
1985	1,779
1986	1,309
After 1986	6,472
Total minimum lease payments	19,039
Less: Amount representing interest	5,755
Total net minimum lease payments*	$13,284

*Includes $2,661 due within one year.

Future minimum rental commitments for the non-cancellable operating leases as of December 31, 1981 are as follows:

1982	$ 8,032
1983	7,332
1984	6,647
1985	6,079
1986	5,323
After 1986	19,306
Total	$52,719

It is expected that minimum rental income from the non-cancellable leases will average $4,860 annually for the next five years, of which an estimated $2,644 annually will relate to sub-leasing of non-cancellable capital leases.

Rental expense includes net rentals applicable to operating leases for service stations, office buildings and other facilities, and charter hire payments applicable to tankers. This excludes rentals in leaseholds to retain mineral rights.

Rental expense for the years ended December 31, 1981, 1980 and 1979 were as follows:

	1981	1980	1979
Minimum rental	**$33,972**	$27,422	$25,235
Less: Rental income on properties sub-leased to others	**26,116**	22,352	17,492
Net rental expense	**$ 7,856**	$ 5,070	$ 7,743

Notes to Consolidated Financial Statements (Continued)

(Expressed in thousands of Canadian dollars)

9. Contingent Liabilities

Under certain service station lease agreements, the Corporation is contingently liable as guarantor for loans by third parties to the lessors which total $5,136 as at December 31, 1981, compared to $5,177 at the end of the previous year. Annual payments are due by the lessors from 1982 through 1986 of $1,579, $1,637, $1,495, $730, and $295 respectively.

Under long-term agreements, the Corporation guarantees capital expenditure and specified revenue from crude oil and natural gas shipped. The Corporation may be required to advance funds against future transportation charges to certain companies in which stock interests are held, in the event such companies are unable to meet specific debt obligations. The contingent liabilities arising from such agreements and various other guarantees, amount to $16,380 at December 31, 1981.

No losses are anticipated by reason of the above contingent obligations. In the opinion of the Corporation's General Counsel, while it is impossible to ascertain the ultimate legal and financial liability with respect to other contingent liabilities, including lawsuits, income taxes, claims, guarantees, etc., the aggregate amount of such liability would not be materially significant in relationship to the total consolidated assets of the Corporation and its subsidiaries.

10. Taxes, Other Than Income Taxes

The significant items comprising taxes, other than income taxes, in the income statement are set forth below:

	Year ended December 31,		
	1981	1980	1979
Property and real estate	**$ 13,228**	$ 11,685	$ 9,870
Federal sales tax	**134,419**	97,524	72,763
Franchise taxes	**16,216**	6,221	1,997
Social benefits	**3,401**	2,509	2,181
Mineral tax—oil	**10,612**	12,095	10,561
Production	**329**	484	338
Other	**2,057**	1,365	1,207
Total	**$180,262**	$131,883	$98,917

In addition, federal excise tax and provincial motor fuel and oil taxes paid or due to taxing authorities for the years ended December 31, 1981, 1980, and 1979, in the amounts of $371,822, $317,780, and $297,105, respectively, have not been included in the income statement.

Crude oil royalties payable in kind are not reflected in the accounts and crude oil royalties payable in cash are accounted for as purchases. Other royalties are not material in amount.

11. Pension Plan

As at December 31, 1981, costs which will be incurred in future years in respect of prior service amounted to approximately $12,443 on a present value basis. These costs are funded by annual payments of $1,688 which will amortize the liability by 1995. The assets of the plan exceed the actuarially computed value of vested benefits as of the last actuarial valuation date .

12. Interest Charges

Interest charges segregated between long-term debt, capitalized leases, and short-term debt included in the income statement are set forth below:

	Year ended December 31,		
	1981	1980	1979
Long-term debt	**$ 8,675**	$ 9,487	$6,503
Capitalized leases	**1,243**	1,621	2,162
Short-term debt	**103**	119	70
Total	**$10,021**	$11,227	$8,735

13. Income Taxes

The provision for deferred income taxes for the years ended December 31, 1981, 1980 and 1979 relates to the following:

	1981	1980	1979
Intangible drilling costs	**$ 9,064**	$21,575	$ 7,954
Non-productive leases	**(690)**	1,178	1,848
Depreciation	**21,760**	15,309	51,384
Inventories	**(1,588)**	11,519	(16,596)
All other	**(6,743)**	(3,188)	3,683
Total	**$21,803**	$46,393	$48,273

The effective income tax rates applicable to income before provision for current and deferred income taxes for the years ended December 31, 1981, 1980 and 1979 were 53.9%, 47.7%, and 49.3% respectively. The reasons for the difference between the effective tax rates and statutory income tax rates theoretically assumed to be applicable to pre-tax book income, were as follows:

	1981	1980	1979
Statutory Federal rate (including surcharge)	**47.8%**	47.8%	46.0%
Less: Provincial abatement	**10.0**	10.0	10.0
	37.8	37.8	36.0
Add: Provincial tax rates	**12.0**	11.7	11.9
Total statutory rate	**49.8%**	49.5%	47.9%
Petroleum and gas revenue tax	**5.1**	–	–
Resource allowance	**(15.7)**	(12.4)	(16.3)
Depletion	**(1.4)**	(2.5)	(1.6)
Disallowed royalties	**21.9**	17.6	20.5
Provincial tax credits and rebates	**(2.4)**	(2.3)	(1.2)
Other	**(3.4)**	(2.2)	–
Effective income tax rate as reflected in the Corporation's accounts	**53.9%**	47.7%	49.3%

14. Segmented Financial Data

Texaco Canada Inc. and its subsidiaries, an integrated organization in the petroleum industry, is engaged in the exploration for and production of crude oil and natural gas and in the refining, transportation and marketing of crude oil and petroleum products. A wholly-owned foreign subsidiary has capital assets related to the petroleum industry which it leases to an affiliated company on a long-term basis. The Corporation's sales revenues and net earnings as reflected in the consolidated statement of income are derived entirely from operations in the petroleum industry, which includes petrochemical activities and assets leased to an affiliated company associated with the petroleum industry, both of which are not material in relation to the total activities of the Corporation.

Notes to Consolidated Financial Statements (Continued)

(Expressed in thousands of Canadian dollars)

15. Research and Development Costs

The Corporation's accounting policy with respect to research and development costs is stated in the Description of Significant Accounting Policies. The amounts charged to expense aggregated $21,236 in 1981, $12,548 in 1980, and $4,905 in 1979.

16. Oil and Gas Producing Activities

Capitalized Costs

Texaco Canada Inc.'s costs relating to oil and gas exploration, development, and producing activities which were capitalized as properties, plant and equipment and related accumulated depreciation, depletion, and amortization were as follows:

	December 31, 1981	December 31, 1980
Proved properties	**$592,988**	$514,006
Unproved properties	**87,528**	93,823
Support equipment and facilities	**12,366**	9,740
Gross capitalized costs	**692,882**	617,569
Related accumulated depreciation, depletion, and amortization	**216,521**	190,765
Net capitalized costs	**$476,361**	$426,804

Amounts capitalized include lease acquisition costs, intangible drilling costs applicable to productive wells, and tangible equipment costs related to the development of oil and gas reserves. These amounts, excluding amounts applicable to support equipment and facilities, are categorized between those properties with proved reserves and those properties with no proved reserves. Support equipment and facilities include amounts capitalized relative to such items as drilling and construction equipment, vehicles, warehouses, camps, district or field offices and service facilities.

Costs Incurred

The following were the costs incurred by the Corporation in oil and gas producing activities during the years ended December 31, 1981, 1980 and 1979. In accordance with the United States Securities and Exchange Commission (S.E.C.) requirements, these costs incurred include costs that are capitalized or charged to expense at the time they are incurred with the exception of support equipment and facilities, for which only appropriate depreciation is included. The S.E.C. regulations also require exclusion of any related income tax effect.

The schedule also reflects the depreciation, depletion, and amortization expense.

	Year ended December 31, 1981	1980	1979
Acquisition of unproved properties	**$ 1,309**	$ 30,282	$ 8,066
Exploration costs	**50,434**	63,074	49,848
Development costs	**79,131**	73,710	34,430
Production costs	**146,290**	62,045	45,181
Total costs incurred	**$277,164**	$229,111	$137,525
Depreciation, depletion, and amortization expense	**$ 27,671**	$ 20,964	$ 20,044

As defined by the S.E.C., the various functional activities of oil and gas production and exploration operations include the following costs incurred:

Property acquisition costs, which are those incurred to purchase, lease or otherwise acquire a property.

Exploration costs, which are those incurred in identifying areas that may warrant examination and examining specific areas that are considered to have prospects of containing oil and gas reserves.

Development costs, which are those incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing the oil and gas.

Production costs, which are cash lifting costs, exclusive of payments for royalties, but include petroleum and gas revenue tax and appropriate depreciation of support equipment and facilities.

The exclusion of payments for income taxes from production costs is specifically required by the S.E.C. However, it is important to note that such income taxes substantially add to the total cost of producing operations and substantially reduce the profitability and cash flow from such operations.

Net Revenues
The net revenues from net oil and gas production for the years ended December 31, 1981, 1980 and 1979, are shown in the following table:

Gross revenues from:	1981	1980	1979
Transfers within Texaco Canada Inc. and sales to unconsolidated affiliates	**$361,260**	$379,791	$516,228
Sales to unaffiliated entities	**321,089**	194,858	43,894
	682,349	574,649	560,122
Less: Production costs	**146,290**	62,045	45,181
Net revenues before estimated income tax effect	**536,059**	512,604	514,941
Estimated income tax effect	**309,574**	249,125	254,896
Net revenues after estimated income tax effect	**$226,485**	$263,479	$260,045

Net revenues represent gross revenues from sales to unaffiliated entities and non-subsidiary companies, as well as transfers among departments and subsidiaries within Texaco Canada Inc., less the related production costs (as defined in the previous section concerning costs incurred). Amounts defined as production costs do not include any expenditures connected with acquisition of, exploration for, and development of oil and gas reserves or any depreciation, depletion, and amortization of such costs that have been capitalized in the Corporation's accounts. In accordance with S.E.C. regulations, net revenue is applicable only to the net oil and gas produced by Texaco Canada Inc. and subsidiary companies. It excludes revenues applicable to oil and gas purchased from unaffiliated entities. Transfers within the Corporation are made at market prices prevailing at the time of the transaction.

17. Reclassification
Certain comparative figures have been reclassified to conform with the 1981 presentation.

Auditors' Report

ARTHUR ANDERSEN & CO.
CHARTERED ACCOUNTANTS

To the Shareholders,
Texaco *Canada Inc.*:

We have examined the consolidated balance sheet of Texaco Canada Inc. and subsidiary companies as of December 31, 1981 and 1980, and the related consolidated statements of income, retained earnings and changes in financial position for each of the three years in the period ended December 31, 1981. Our examinations were made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, the accompanying consolidated financial statements present fairly the financial position of Texaco Canada Inc. and subsidiary companies as of December 31, 1981 and 1980, and the results of their operations and changes in their financial position for each of the three years in the period ended December 31, 1981, in accordance with generally accepted accounting principles applied on a consistent basis.

Toronto, Ontario
February 8, 1982.

Arthur Andersen & Co.

Other Oil and Gas Producing Activities

Net Proved Developed and Undeveloped Reserves

All of the Corporation's net proved reserves are located in Canada.

There are no crude oil and natural gas reserves applicable to long-term supply or similar agreements with foreign governments or authorities in which the Corporation acts as producer.

	Crude Oil and Natural Gas Liquids (millions of cubic metres)	Natural Gas (billions of cubic metres)
Net proved developed and undeveloped reserves		
*As of December 31, 1978	59.0	40.3
Increase (decrease) during 1979 attributable to:		
Revisions of previous estimates	1.1	(0.8)
Extensions, discoveries and other additions	2.1	3.1
Production	(6.4)	(0.9)
*As of December 31, 1979	55.8	41.7
Increase (decrease) during 1980 attributable to:		
Revisions of previous estimates	(0.2)	1.8
Extensions, discoveries and other additions	2.3	2.2
Production	(5.5)	(2.0)
*As of December 31, 1980	52.4	43.7
Increase (decrease) during 1981 attributable to:		
Revisions of previous estimates	(2.0)	(1.4)
Extensions, discoveries and other additions	0.7	2.9
Production	(5.3)	(0.9)
*As of December 31, 1981	45.8	44.3
*Includes net proved developed reserves of Texaco Canada Inc. and subsidiary companies:		
As of December 31, 1978	59.0	39.9
As of December 31, 1979	55.8	41.3
As of December 31, 1980	52.4	43.3
As of December 31, 1981	45.7	41.1

Net reserves represent the volume estimated to be available after deduction of royalties.

In previous years, net reserves have been determined using the then current year-end prices and royalty structure. As of December 31, 1981, net reserves have been computed giving consideration to known price increases in old oil resulting from pricing agreements between the governments of Canada and the producing provinces. The use of these price increases for old oil has been limited to 75% of the world crude oil prices existing as at December 31, 1981. New oil will be sold at world prices. The effect of this change is reflected in the Revision of Previous Estimates in 1981.

The foregoing reserve figures are believed to be reasonable estimates consistent with current knowledge of the characteristics and extent of proved production. They include only such reserves as can reasonably be classified as proved. The estimates of natural gas reserve quantities include the volume of the percentage of natural gas liquids which may be removed at locations beyond lease and/or field separation facilities. Estimates of reserve quantities are based on sound geological and engineering principles, but by their very nature are still estimates that are subject to upward or downward revision as additional information regarding producing fields and technology becomes available. Since estimating underground reserves is not, and does not purport to be an exact science, the potential for subsequent revisions in estimates is high, particularly as such reserves increase in maturity.

Estimated Valuation of Net Proved Developed and Undeveloped Reserves

The Securities and Exchange Commission (S.E.C.) has announced in 1981 that it no longer considers reserve recognition accounting widely known as RRA to be a potential method of accounting in the primary statements of oil and gas producers. At this time the Financial Accounting Standards Board is developing a comprehensive package of oil and gas activity disclosures. Meanwhile, the Corporation is continuing to report in accordance with the S.E.C. Reserve Recognition Accounting method.

The information provided below is based on estimated underground reserves as presented in the previous section entitled "Net Proved Developed and Undeveloped Reserves" and this note should be read in conjunction with that disclosure. The estimated valuations of underground reserves are also of necessity based on estimates, and this and the previous disclosure contain appropriate caveats with respect to the use and interpretation of the data resulting from such estimates.

The following data are presented:

Estimated future net revenues from net production of estimated net proved oil and gas reserves as of December 31, 1981.

Present value of estimated future net revenues from net production of estimated net proved oil and gas reserves as of December 31, 1981, 1980, and 1979.

Reserve Recognition Accounting

Supplemental summary on an RRA basis of additions and revisions to present value of estimated future net revenues resulting from oil and gas exploration, development and producing activities during 1981, 1980 and 1979.

Analysis of changes in estimated present value of future net revenues for the years ended December 31, 1979 to 1981, on an RRA basis.

Texaco Canada Inc. is presenting the information listed previously in good faith in compliance with the regulations of the S.E.C. While the Corporation has exercised all due care in developing the data, it is necessary to caution investors and other users of this information to avoid its simplistic use. Users should carefully read the financial information presented in the following tables in conjunction with the accompanying qualifications and caveats, as well as with those included in the section entitled "Net Proved Developed and Undeveloped Reserves".

There are many variables, assumptions and imprecisions inherent in the development of estimated future net revenues to be derived from estimated production of net proved oil and gas reserves and the present values of such estimated future net revenues. Future net revenues are based on prices and royalties in effect as at December 31, 1981, except for old oil. The prices and royalties for old oil have been increased in accordance with the pricing agreements between the governments of Canada and the producing provinces, but the prices have been limited to 75% of current world prices. In addition, the projections of estimated future net revenues are affected by a multiplicity of factors which are subject to fluctuation, thereby unavoidably making the projections subject to the possibility of a wide range of variation. These factors include such items as revisions in the estimated quantities of producible reserves; timing of production; future technological and economic conditions; and future government actions regarding production, taxes, royalties, etc.

Since projections of future revenues and costs are highly subjective, actual net revenues and cash flow to be derived by the Corporation from future production could differ substantially from the estimated amounts set forth in the various tables in this note. Accordingly, Texaco Canada Inc. urges that extreme care be exercised in the use of the data.

Estimated Future Net Revenues

(Expressed in thousands of Canadian dollars)

The estimated future net revenues from estimated future net production of estimated net proved oil and gas reserves as of December 31, 1981 are shown in the following table:

	Developed	Undeveloped	Total
From proved reserves:			
1982	$ 715,783	$ (4,271)	$ 711,512
1983	885,311	11,095	896,406
1984	806,529	9,258	815,787
After 1984	6,138,696	214,706	6,353,402
Total	$8,546,319	$230,788	$8,777,107

Other Oil and Gas Producing Activities (Continued)

These estimates have been computed by applying prices and costs known to be in effect during the periods reported (subject to prices for old oil having a ceiling of 75% of current world crude oil prices) to estimated future production of those proved reserves of crude oil, natural gas liquids and natural gas shown in the section entitled "Net Proved Developed and Undeveloped Reserves". Costs consist of estimated lifting costs (including petroleum and gas revenue tax) plus estimated future expenditures to be incurred in developing the reserves, assuming continuation of existing economic conditions. These costs, however, exclude depreciation, depletion, and amortization of capitalized costs, in accordance with S.E.C. rules.

The net revenues are before recognition of estimated income tax and Incremental Oil Revenue Tax effects as specified in the S.E.C. regulations. However, income taxes and the Incremental Oil Revenue Tax would substantially add to the total cost of producing operations and substantially reduce the profitability and cash flow from such operations. Based on existing tax rates, the estimated effect of income taxes and Incremental Oil Revenue Tax would be a reduction in estimated future net revenues of approximately $5,519,000.

Present Value of Estimated Future Net Revenues

(Expressed in thousands of Canadian dollars)

Shown below is the present value of the estimated future net revenues from estimated reserves as of December 31, 1981, 1980, 1979 and 1978 as calculated in the previous years. The discount rate utilized in this computation is ten per cent, as specified by the S.E.C. The use of a specified uniform discount rate does not permit recognition of such factors as differences in the degree of risk of operating in different parts of Canada and in frontier areas, the availability of financing, and the state of the economy. On this basis, the present value of estimated future net revenues is as follows:

	As of December 31, 1981		
	Developed	Undeveloped	Total
From proved reserves:			
1982	$ 681,161	$ (4,065)	$ 677,096
1983	762,315	9,553	771,868
1984	628,391	7,213	635,604
After 1984	2,127,574	68,518	2,196,092
Total	$4,199,441	$ 81,219	$4,280,660

	As of December 31, 1980		
	Developed	Undeveloped	Total
From proved reserves:			
1981	$ 562,916	$ –	$ 562,916
1982	508,849	–	508,849
1983	469,039	–	469,039
After 1983	1,971,120	5,867	1,976,987
Total	$3,511,924	$5,867	$3,517,791

	As of December 31, 1979		
	Developed	Undeveloped	Total
From proved reserves:			
1980	$ 491,449	$ 143	$ 491,592
1981	480,976	588	481,564
1982	438,081	928	439,009
After 1982	1,681,254	7,283	1,688,537
Total	$3,091,760	$8,942	$3,100,702

	As of December 31, 1978		
	Developed	Undeveloped	Total
From proved reserves:			
1979	$ 330,242	$ –	$ 330,242
1980	316,235	–	316,235
1981	306,631	–	306,631
After 1981	1,790,446	8,707	1,799,153
Total	$2,743,554	$8,707	$2,752,261

The present value amounts as of December 31, 1981 give effect to the crude oil price and natural gas increases which have occurred as a result of the Federal/Provincial pricing agreements.

Reserve Recognition Accounting

Reserve Recognition Accounting (RRA) is a supplemental disclosure for reporting oil and gas reserves and exploration, development and producing activities which is required by the Securities and Exchange Commission.

Under the RRA concept, income would be recognized when oil and gas reserves are discovered, based on the present value of estimated future net revenues to be derived from the future production of such reserves. Adjustments to income would be recorded to reflect changes in estimates of reserve quantities, of future prices, of future costs, and of timing of production. All costs associated with finding and developing reserves, together with all non-productive costs incurred (such as dry holes, exploration costs and impairments), would be reflected as charges against income. Certain costs, such as lease acquisition costs and exploratory drilling costs, would initially be deferred pending determination of whether or not reserves have been discovered. Upon such determination, these costs would be charged to expense either as a non-productive cost or as a cost of finding reserves.

The RRA method of income determination differs from the recognition of income and earnings under existing generally accepted accounting principles in two major respects. First, under RRA the value of oil and gas reserves would be recorded as income when discovered, rather than when oil and gas are produced and sold as under existing accounting principles. Second, except for certain costs which are initially deferred under RRA, all acquisition and development costs are charged off to expense as incurred rather than being capitalized and charged to expense in future periods through depreciation, depletion, and amortization.

Texaco Canada Inc. is not in accord with the principle of Reserve Recognition Accounting for the following principal reasons: Estimates of underground reserve quantities, while essential and satisfactory for other purposes, are not sufficiently reliable, verifiable and comparable for use as a basis for valuing reserves for financial statement purposes due to the unavoidable subjectivity involved in estimating reserves and the fact that such estimates by their very nature are subject to substantial upward or downward revision as additional production information and technology becomes available; RRA represents a departure from the realization concept of income recognition; RRA is a premature substitution of value accounting for historical cost accounting which has not been preceded by adequate study and research to demonstrate that a sound principle and acceptable methods of application have been developed. As a result of the foregoing deficiencies, Texaco Canada Inc. is of the opinion that value data prepared on the RRA basis are not reliable for meaningful analysis.

Summary of Oil and Gas Producing Activities on the Basis of Reserve Recognition Accounting

(Expressed in thousands of Canadian dollars)

The following table summarizes oil and gas exploration and development activities on the RRA basis for the years ending December 31, 1981, 1980 and 1979.

	1981	1980	1979
Revisions and additions to the present value of estimated proved oil and gas reserves			
Revisions of beginning of year estimates			
Change in prices	**$1,883,483**	$668,928	$446,828
Other revisions, including changes in costs, and revisions of previous volume estimates	**(1,171,823)**	(222,881)	(79,854)
Accretion of discount	**369,369**	325,574	288,987
Extensions, discoveries and other additions from exploration and development activities during current year (net of production and development costs)	**148,260**	99,611	185,549
Total revisions and additions, present value	**1,229,289**	871,232	841,510
Less: Acquisition, exploration and development costs associated with additions and revisions to proved reserves plus all non-productive costs incurred during the current year	**69,977**	59,144	55,252
Net revisions and additions in present value of proved reserves in excess of costs	**1,159,312**	812,088	786,258
Estimated income tax effect	**1,240,275**	426,813	333,739
Total net revisions and additions in present value of proved reserves during the year, after estimated income tax effect	**$ (80,963)**	$385,275	$452,519

Other Oil and Gas Producing Activities (Continued)

The reader is cautioned that the foregoing total net revisions and additions in present value of proved reserves should not be considered indicative of the Corporation's earnings or cash flow from exploration, development and producing activities during each year. Rather, this amount is merely a notional computation derived under a supplemental disclosure concept. Furthermore, the 1981 data include the many provisions outlined in the National Energy Program and the Federal-Provincial pricing agreements. The most significant item of this program and pricing agreements which adversely affected the 1981 results was the application of the Petroleum and Gas Revenue Tax. The increase in the estimated income tax effect for 1981 reflects in part the non-deductibility of the Petroleum and Gas Revenue Tax for income tax purposes. For 1981, the Petroleum and Gas Revenue Tax equalled 8% of producing revenues less certain lifting costs. For succeeding years, the rate of tax has been increased to an effective rate of 12%.

Further information with respect to the Summary of Oil and Gas Producing Activities on the Basis of Reserve Recognition Accounting follows:

The present value amount of $1,883,483 in 1981, attributable to the change in prices, reflects the increases in oil and gas prices which occurred during 1981 as well as future increases in old oil prices as set out in the pricing agreements between the governments of Canada and the producing provinces. The present value amounts of $668,928 and $446,828 reflect only the oil and gas price increases which occurred during 1980 and 1979, respectively.

The accretion of discount is the amount by which the present value of estimated future net revenue from estimated net production of proved oil and gas reserves at the beginning of the year increased during the current year due to the passage of time. The amount of adjustment was computed under a compound interest method which resulted in an effective rate of approximately 10.5%.

As mentioned previously, under RRA the costs applicable to property acquisition and exploratory drilling are deferred pending determination of whether or not proved reserves are found. Such costs that have been deferred on an RRA basis as of December 31, 1981 amounted to $76,568, $79,127 as of December 31, 1980 and $47,318 as of December 31, 1979. Upon determination that reserves have or have not been found, such costs will be expensed. This deferred cost amount includes a valuation reserve of $33,238 at the end of 1981, $25,799 at the end of 1980 and $20,206 at the end of 1979, which reflects allowances for impairment in value of non-productive leases provided during the current year in the amount of $8,498 for 1981, $6,727 for 1980 and $5,228 for 1979.

The RRA estimated income tax effect includes the following elements: taxes payable on income realized from operations in oil and gas exploration, development and producing activities; as well as the change in the notional tax liability applicable to the present value of future net revenues between the beginning and end of each year.

The pre-tax profit contribution for financial reporting purposes from oil and gas producing activities that is included in the Consolidated Statement of Income is $453,077 for the year 1981, $457,165 for the year 1980 and $431,077 for the year 1979. These amounts represent the revenues received from sales of net oil and gas production, less costs and expenses incurred in the oil and gas exploration, development and producing activities of Texaco Canada Inc. and subsidiary companies.

Summary of Changes in Present Value

(Expressed in thousands of Canadian dollars)

The following table sets forth an analysis of changes in the present value of estimated future net revenues from net production of net proved oil and gas reserves during the years ended December 31, 1981, 1980 and 1979, before estimated income tax effects. These data are presented under the caption "Present Value of Estimated Future Net Revenues" on page 38 of this report.

	1981	1980	1979
Present value of estimated future net revenues at beginning of period....	**$3,517,791**	$3,100,702	$2,752,261
Revisions and additions as set forth in supplemental Reserve Recognition Accounting summary on page 39	**1,229,289**	871,232	841,510
Sale of produced oil and gas, net of production costs	**(536,059)**	(512,604)	(514,941)
Expenditures during year of development costs included in the present value of estimated future net revenues at beginning of period	**69,639**	58,461	21,872
Present value of estimated future net revenues at end of period	**$4,280,660**	$3,517,791	$3,100,702

Reporting for the Effects of Changing Prices

The Canadian Institute of Chartered Accountants (C.I.C.A.) recently issued an exposure draft on Reporting the Effects of Changing Prices for consideration by accountants and other affected or interested individuals. This exposure draft proposes a method of reporting which combines current cost accounting and constant dollar accounting.

The C.I.C.A. will be analyzing the comments received in response to this exposure draft. Final recommendations and implementation is expected for annual reports with year ends after December 15, 1982. In view of the aforementioned and the fact that the Corporation is exempt from the S.E.C. disclosure requirements regarding current changing prices, the Corporation is continuing to review its alternatives in order to determine the most informative basis of presentation.

Selected Quarterly Financial Data

(Expressed in thousands of Canadian dollars except per share data)

For the three months ended:	Sales and services	Gross profit	Net income	Net income per common share
March 31, 1981	$1,086,009	$180,832	$91,459	$0.71
June 30, 1981	1,068,854	149,005	80,676	0.63
September 30, 1981	1,091,539	153,703	81,466	0.63
December 31, 1981	1,128,930	126,742	62,705	0.48
March 31, 1980	817,463	166,997	93,212	0.73
June 30, 1980	809,272	157,433	89,252	0.69
September 30, 1980	885,765	165,377	95,326	0.75
December 31, 1980	990,679	166,691	95,628	0.75
March 31, 1979	623,254	94,870	48,076	0.36
June 30, 1979	572,954	91,383	52,677	0.39
September 30, 1979	656,725	122,002	68,082	0.52
December 31, 1979	785,690	174,289	95,060	0.74

Certain comparative figures have been reclassified to conform with the 1981 presentation.

Except for interest charges and provision for current and deferred income taxes, all deductions reported in the Consolidated Statement of Income have been deducted as costs and expenses associated directly with or allocated to sales and services to arrive at gross profit.

In accordance with the Corporation's accounting policy, inventories of crude oil and petroleum products are stated at cost, determined on the first-in, first-out method. Effective April 1, 1980, the Alberta Petroleum Marketing Commission took effective control of all oil produced from Crown property in the Province of Alberta. Commencing on this date the Corporation valued its inventories of oil produced from Crown property in the Province of Alberta at the price paid to the Alberta Petroleum Marketing Commission, whereas in prior periods, related inventories were stated at the Corporation's cost of producing the product. This action resulted in improved net income for the second quarter of 1980 by $25,464 equal to $0.21 a common share, for the third quarter of 1980 by $4,189 equal to $0.04 a common share, and for the fourth quarter of 1980 by $1,428 equal to $0.01 a common share.

Selected Financial Data

(Expressed in millions of Canadian dollars except per share data)

	Year ended December 31,				
	1981	1980	1979	1978	1977
Sales and services	**$4,375.3**	$3,503.2	$2,638.6	$1,902.1	$1,710.2
Net income from continuing operations	**316.3**	373.4	263.9	154.1	149.9
*Net income per common share from continuing operations	**2.45**	2.92	2.01	1.10	1.07
Total assets	**2,879.1**	2,603.1	2,299.7	1,762.9	1,591.7
Long-term debt	**$ 75.0**	$ 84.6	$ 93.8	$ 100.1	$ 100.1
Long-term capital lease obligations	**10.6**	13.4	16.1	28.9	34.5
Deferred gas production revenue	**16.3**	11.1	–	–	–
Redeemable preferred stock	**250.0**	290.0	290.0	290.0	290.0
Total long-term obligations	**$ 351.9**	$ 399.1	$ 399.9	$ 419.0	$ 424.6
Cash dividends declared per common share					
* Texaco Canada Inc.	**$0.82**	$0.585	$0.42	$0.195	$ –
** Texaco Canada Limited	–	–	–	0.78	1.56
** Texaco Exploration Canada Ltd.	–	–	–	–	32,800.00

*Based on the average number of common shares outstanding after adjusting for the four-for-one split which occurred on August 15, 1980.

**Texaco Canada Inc. is the continuing corporation of the June 1, 1978, amalgamation of Texaco Canada Limited and Texaco Exploration Canada Ltd.

Five-Year Review

(Expressed in millions of Canadian dollars except where noted)

	1981	1980	1979	1978	1977
Financial Summary					
Revenues	**$4,461.0**	$3,572.0	$2,684.9	$1,928.4	$1,734.6
Net income	**316.3**	373.4	263.9	154.1	149.9
Per common share (dollars)	**2.45**	2.92	2.01	1.10	1.07
Per dollar of revenues (cents)	**7.1**	10.5	9.8	8.0	8.6
Dividends paid or accrued					
Common shares	**98.9**	70.5	50.6	31.1	48.0
First preferred shares	**0.1**	0.1	0.2	0.2	0.2
Second preferred shares					
Series A	**12.8**	12.8	12.8	7.4	–
Series B	**7.7**	8.7	8.7	5.1	–
Funds flow					
Provided by operations	**404.5**	460.8	386.6	281.7	210.9
Per common share (dollars)	**3.35**	3.82	3.21	2.34	1.75
Capital and exploratory expenditures	**209.3**	224.2	136.6	186.0	226.7
Taxes paid or accrued and deferred income taxes					
Provision for current and deferred income taxes	**369.6**	340.7	256.2	143.6	146.8
Crown royalties, import duties, and other levies including the petroleum compensation charge	**807.9**	350.7	267.7	169.4	142.4
Taxes other than income taxes	**180.3**	131.9	98.9	93.2	85.4
Taxes collected from consumers	**371.8**	317.8	297.1	296.8	302.0
Petroleum and gas revenue tax	**71.5**	–	–	–	–
Total	**$1,801.1**	$1,141.1	$ 919.9	$ 703.0	$ 676.6

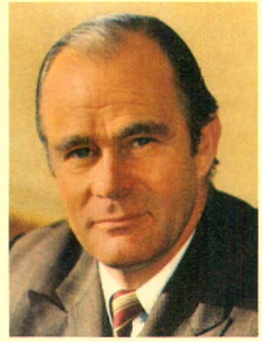
	1981	1980	1979	1978	1977
Financial Position at Year-End					
Current assets	**$1,396.7**	$1,198.4	$1,026.6	$ 501.9	$ 635.0
Current liabilities	**640.0**	537.0	549.0	250.1	279.2
Working capital	**756.7**	661.4	477.6	251.8	355.8
Properties, plant and equipment—net	**1,279.6**	1,203.3	1,081.2	1,056.0	930.1
Investments, long-term receivables and other assets	**202.8**	201.4	191.9	205.0	26.6
Capital employed	**2,239.1**	2,066.1	1,750.7	1,512.8	1,312.5
Long-term debt	**75.0**	84.6	93.8	100.1	100.1
Capital lease obligations	**10.6**	13.4	16.1	28.9	34.5
Deferred gas production revenue	**16.3**	11.1	–	–	–
Deferred income taxes	**407.7**	384.3	349.4	284.0	187.0
Redeemable preferred stock	**250.0**	290.0	290.0	290.0	290.0
Preferred stock	**1.1**	2.5	3.0	3.7	3.8
Common stock and retained earnings	**1,478.4**	1,280.2	998.4	806.1	697.1
Equity per common share (dollars)	**12.25**	10.62	8.28	6.69	5.79
Return on average capital employed (per cent)	**14.9**	19.9	16.4	11.5	12.6
Current working capital ratio	**2.2**	2.2	1.9	2.0	2.3

Per common share information has been adjusted for the four-for-one split which occurred on August 15, 1980.

	1981	1980	1979	1978	1977
Operations Summary					
(In thousands of cubic metres daily)					
Production of crude oil and natural gas liquids					
Gross	**23.5**	24.0	26.7	19.5	19.7
Net	**15.2**	15.6	17.4	13.0	13.3
Refinery runs	**28.2**	29.8	30.8	26.0	25.0
*Refinery crude oil capacity at year-end	**34.6**	33.9	33.9	41.6	26.0
Petroleum product sales	**31.6**	33.8	32.9	30.6	29.8
Natural gas sales (millions of cubic metres daily)	**3.3**	2.4	2.2	2.0	2.4
Number of Wells Drilled					
Gross	**114**	240	103	119	107
Net	**43.2**	71.1	26.5	31.2	31.8
Estimated Gross Proved Recoverable Reserves					
Oil (million cubic metres)	**71.8**	81.6	86.3	85.7	89.9
Gas (billion cubic metres)	**65.2**	60.9	58.8	54.8	53.6
Share Ownership					
(At year-end)					
Number of common shares outstanding	**120,680,872**	120,568,864	120,532,560	120,475,728	120,470,448
Number of common shareholders	**5,366**	5,592	4,038	4,210	4,664
Number of first preferred shares outstanding	**11,197**	25,198	29,736	36,840	37,500
Number of first preferred shareholders	**132**	308	409	493	534
Employees					
Number at year-end	**4,522**	4,442	4,265	4,419	4,413
Payroll and benefits	**$146.6**	$126.2	$109.0	$101.9	$91.6

*Refinery crude oil capacity at year-end 1981, 1980 and 1979 does not include idle capacity at the refinery in Port Credit, Ontario.

Directors of Texaco Canada Inc.



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*Andrew G. Farquharson
Retired. Formerly President
and Chief Executive Officer
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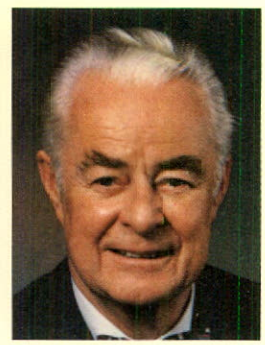

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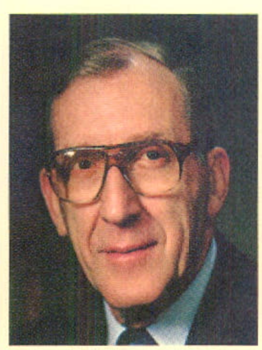

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Lindwood Holdings Limited
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**Charles I. Rathgeb
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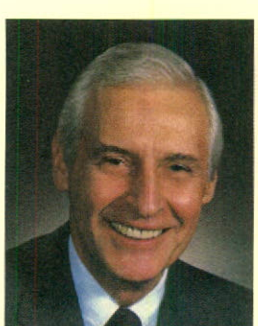
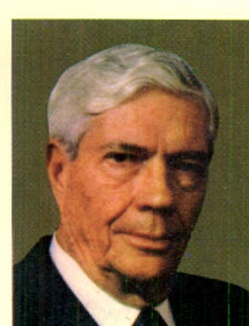
Comstock International Ltd.
Toronto

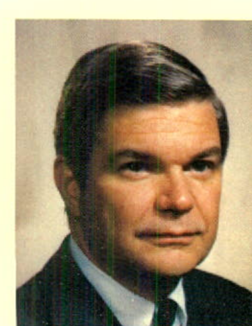


*‡Roland M. Routhier
President and Chief
Executive Officer
Texaco Canada Inc.
Toronto

**Neil M. Shaw
Group Managing Director
Tate & Lyle Limited
United Kingdom



R. W. Sparks
Chairman of the Board
Texaco Canada Inc.
Toronto

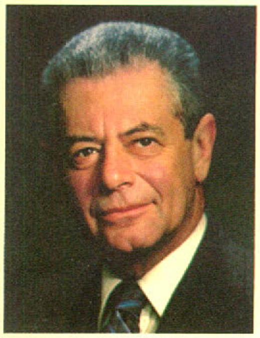


*‡William K. Tell, Jr.
Senior Vice-President
Texaco Inc.
White Plains, New York

*Member of the
Executive Committee

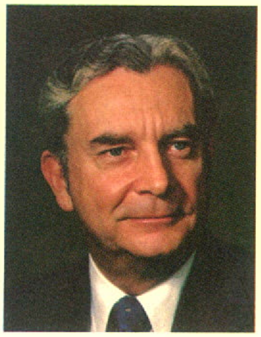
**Member of the
Audit Committee

Other Officers

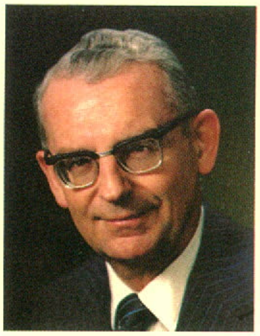


O. C. Cleyn
Vice-President, Eastern Canada and Region Manager

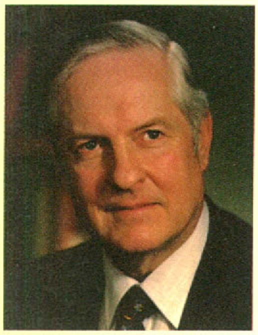
A. J. Galipeault
Vice-President and General Counsel



K. D. Keegan
Vice-President and Treasurer

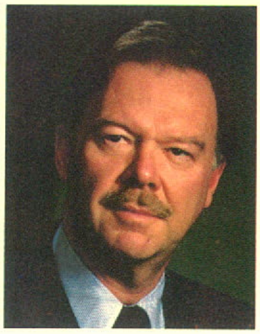


J. M. Murray
Vice-President and General Manager, Refining



C. S. Ramsay
Vice-President and General Manager, Employee Relations

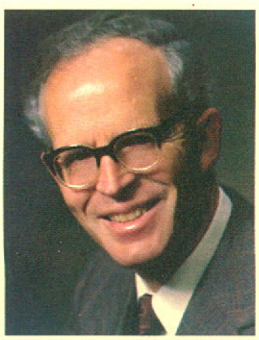
N. E. Taylor
Vice-President and General Manager, Marketing



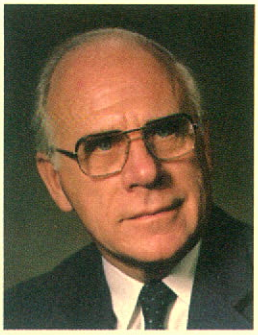
S. J. Walker
Vice-President and General Manager, Supply and Distribution

J. C. Wattie
Vice-President, Personnel and Corporate Services

E. J. Little
Corporate Secretary and Director of Public Affairs



P. M. Taylor
Corporate Tax Officer



D. L. West
Comptroller

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