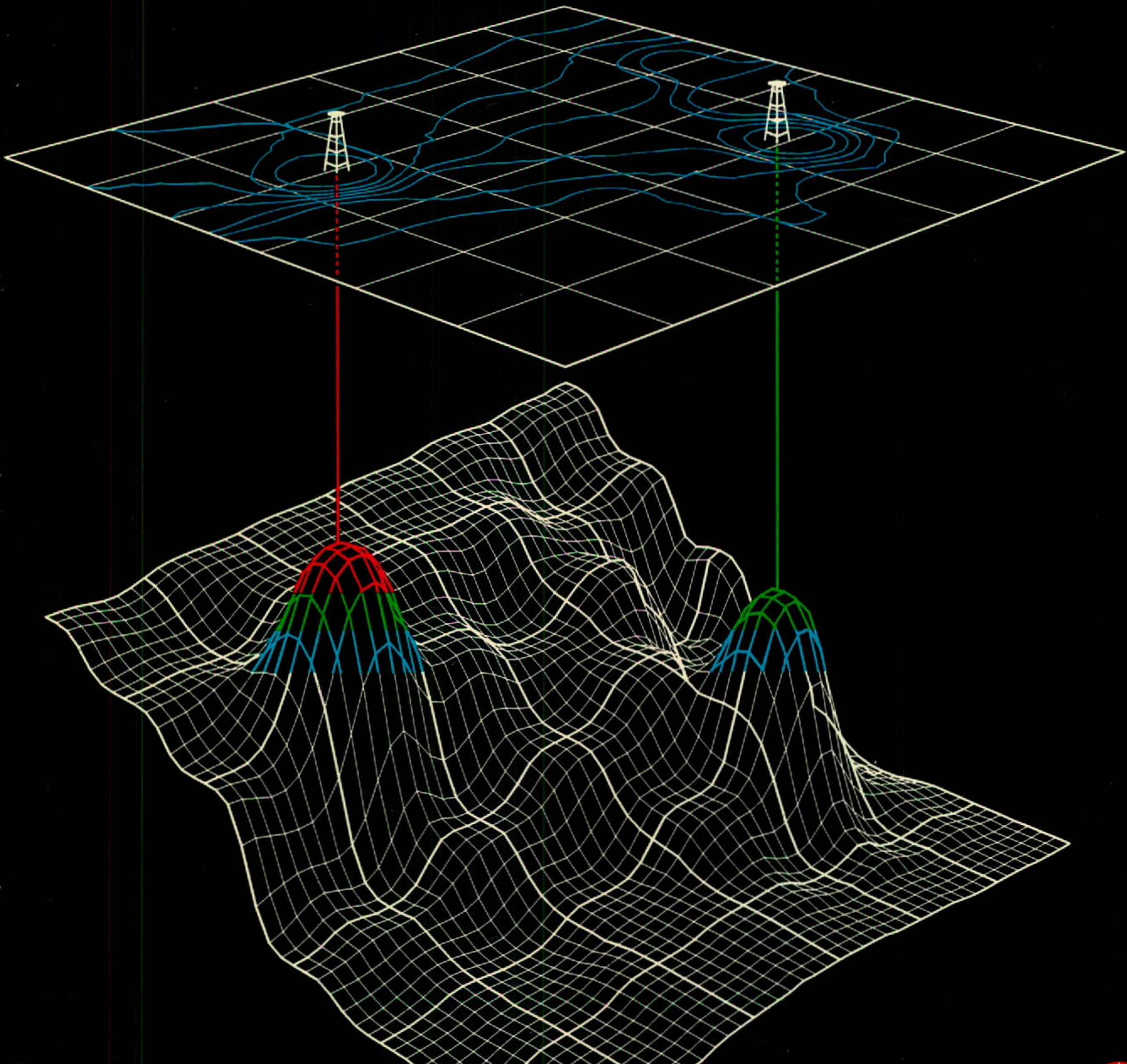
Texaco Canada Inc.

Annual Report

1985



Corporate Profile

Texaco Canada Inc. is a fully integrated petroleum company engaged in the exploration for and production of crude oil, natural gas liquids and natural gas, and in the refining, transportation and marketing of crude oil and petroleum products.

The company operates refineries at Nanticoke, Ontario, and at Halifax, Nova Scotia, and has contracts for processing capacity in Quebec and Alberta. These facilities and an extensive distribution system support the company's position as a major competitor in the marketing of petroleum products throughout Canada.

Exploration and production activities are managed through Texaco Canada Resources Ltd., a wholly owned subsidiary, and Texaco Canada Resources, a limited partnership, both of Calgary, Alberta. Texaco Canada is currently the largest producer of conventional crude oil and natural gas liquids in Canada.

Texaco Canada has consistently generated among the highest returns in the Canadian oil and gas industry and is one of the country's most financially sound corporations. It is management's intention to employ the company's substantial financial resources in a fiscally responsible manner to maintain and increase its petroleum reserve base, to remain a competitive force in the manufacture and sale of petroleum products, and to meet the new challenges of an ever-changing industry. Throughout all endeavors undertaken in this regard, management's fundamental objective is to maximize the value of Texaco Canada Inc. to its shareholders.

Seventy-eight per cent of Texaco Canada's common shares are owned directly or indirectly by Texaco Inc. of White Plains, New York.

Contents

Cover:
This computer generated graphics display was produced using subsurface and contour map display software developed by Texaco Canada. Green depicts deposits of crude oil; red, natural gas; and blue, water. The company has been intensifying its application of advanced computer-graphics methods to solve exploration and producing problems.

Texaco Canada Inc.
90 Wynford Drive
North York, Ontario
M3C 1K5

The Annual Meeting of Shareholders of Texaco Canada Inc. will be held in the Vanity Fair Ballroom, at the King Edward Hotel, 37 King Street East, Toronto, Ontario, on Friday, May 2, 1986, at 10 a.m. local time.

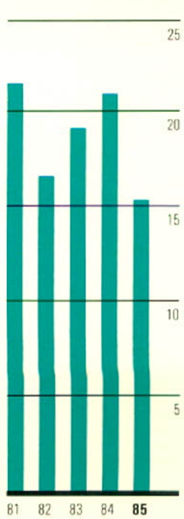
On peut obtenir un exemplaire français du présent rapport annuel en s'adressant au secrétaire général de la société, 90 Wynford Drive, North York (Ontario) M3C 1K5

Highlights

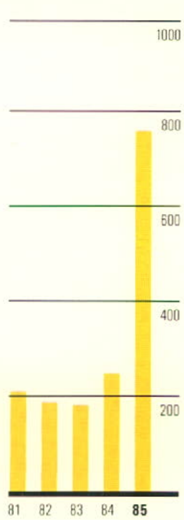
Financial	1985	1984	Per cent Increase (Decrease)
	Millions of Canadian dollars		
*Revenues	$4,304	$4,358	(1)
Net income	336	423	(21)
Cash from operations	516	549	(6)
Taxes and Crown royalties	1,892	1,981	(5)
Capital and exploration expenditures (inclusive of the $495 acquisition cost of Canadian Reserve)	762	245	211
Total assets at year-end	3,631	3,409	7
Common shareholders' equity at year-end	2,274	2,089	9
Long-term debt at year-end	94	94	–
Rate of return on average capital employed	12.0%	16.2%	(26)
Rate of return on average shareholders' equity	15.2%	21.0%	(28)
Per Common Share Data			
Net income	$ 2.74	$ 3.41	(21)
Cash dividends	1.20	1.20	–
Shareholders' equity at year-end	18.83	17.30	9
Operating			
	Thousands of cubic metres daily		
Gross production of crude oil and natural gas liquids	23.4	24.1	(3)
Refinery input	21.9	20.9	5
*Petroleum product sales	25.4	25.3	–
	Millions of cubic metres daily		
Natural gas sales	4.1	3.2	28
	Cubic metres		
Estimated gross proved recoverable reserves:			
Crude oil and natural gas liquids (millions)	66.2	64.0	3
Natural gas (billions)	62.8	51.4	22

*Revenues and petroleum product sales have been reclassified as described in Note 2 to the Consolidated Financial Statements.

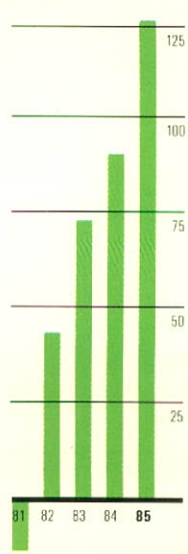
Rate of Return on Average Shareholders' Equity
Per cent



Capital and Exploration Expenditures
Millions of dollars



Gross Crude Oil and Natural Gas Liquids Replacement
Per cent



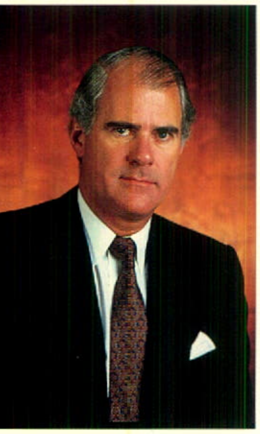
Report to Shareholders

The nature of our business has been fundamentally changed during the past year by several significant events: Canadian crude oil prices, which had been under government control for more than a decade, were deregulated, and moves were begun to decontrol domestic natural gas prices. In January of this year, world prices began a precipitous slide that has reduced the market value of crude oil by more than 50 per cent.

Our challenge in this rapidly changing environment is to protect the value of the company during 1986 so that, in the longer term, we can continue to maximize its value to you, the shareholder. Our objective is to add profitable reserves and ultimately increase production. In refining and marketing, we are determined to improve profits and the return on our investments.

Your company ended 1985 in an excellent financial position with a strong balance sheet, low debt and substantially improved cash flow from all operations. The company continued to lead the major integrated oil companies with a return on average shareholders' equity of 15.2 per cent.

Texaco maintained its dividend at $1.20 per share in 1985. The company has an unbroken record of paying dividends since 1944. Historically, dividends have been in the range of 30 to 40 per cent of earnings and are comparable with industry averages. The dividend policy aims for an appropriate balance between earnings reinvested and those paid to shareholders.



Earnings

Earnings declined to $336 million in 1985 from $423 million in 1984 due to lower crude oil production, higher expenses in the exploration and producing segment and an unusual inventory adjustment. These factors were partially offset by improved profits in the petroleum products business.

The decline in liquids production stemmed from insufficient pipeline capacity in the Interprovincial Pipeline System and the Alberta government's system of market prorationing. "Prorationing" is a government-regulated system for sharing among producers the available market demand. Prorationing forced Texaco Canada to leave an average of 920 cubic meters a day of oil in the ground during 1985. Production was also lower because of the natural decline in productivity in some of the company's older fields. Higher operating costs, especially for enhanced oil recovery projects, also had a negative impact on earnings.

The unusual inventory adjustment resulted from a change in the pattern of selling crude oil to the Alberta Petroleum Marketing Commission. This change was coincident with deregulation in June, 1985 and led to a $34 million deferral of profit, which accounted for nearly 40 per cent of the 1985 decline in earnings.

Some of 1985's good news came from an earnings turnaround in the refining and marketing business, which produced a profit of $39 million. This was a positive swing of $42 million from the $3 million downstream loss in 1984.

Major Events

We acquired Canadian Reserve Oil and Gas Ltd. for $495 million in early 1985 from a subsidiary of Texaco Inc. and during the year we successfully integrated that company into our energy resource sector. Canadian Reserve's cash flow made a valuable contribution to the company.

The acquisition was part of our strategy for profitable reserves additions and helped the company achieve a 126 per cent replacement of liquids production, the fourth consecutive year of improvement in this ratio.

The final step toward integrating Canadian Reserve into the Texaco Canada organization was taken in February 1986, when most of the energy resource assets in western Canada were transferred to a new limited partnership which is called Texaco Canada Resources (TCR). The move reorganizes a major portion of upstream operations into a more efficient business organization.

We accelerated our expenditures in the energy resource sector in 1985 to advance our diversified reserves replacement thrust. The key elements of our strategy for the year included exploration in western Canada, frontier exploration, foreign exploration, enhanced oil recovery, natural gas liquids recovery through gas processing, oil sands and heavy oil projects, and acquisitions.

Our refining and marketing business responded to the challenge of declining product demand by adopting strategies to eliminate excess capacity, reduce operating costs and capital employed, increase efficiency in administrative and operational processes and improve financial management at the field level. The overriding objective is to improve the company's return on invested capital.

We announced an $80 million investment in Nanticoke refinery which is now well underway, improving energy efficiency and allowing us to produce more of the valuable light products from each barrel of crude oil. We closed the Port Credit chemical facility because it was not cost competitive.

The Marketing Department began reshaping its organization and business methods to improve efficiency and financial accountability throughout the organization.

Another major event in 1985 was the $484.4 million secondary offering of Texaco Canada shares by Texaco Inc. This record equity issue in Canada, which increased Texaco Canada's level of public ownership from approximately 10 per cent to 22 per cent, was over subscribed, reflecting a high level of investor confidence.

Outlook

The steep and precipitous oil price fall is a key factor in the 1986 outlook for our industry. The price decline reflects a worldwide excess production capacity which presently overhangs the market. Just as the industry had to deal with sudden changes when prices increased in 1973 and again in 1979, we are now experiencing equally significant changes with the abrupt decline to pre-1979 levels.

This sudden downward shift in the market value of petroleum significantly affects the current economics of our business. The worldwide petroleum industry is in a period of transition and adjustment which is reducing profitability in the exploration and production sector. However, as an integrated company, we may have the opportunity to offset some of the decline through better returns from the company's petroleum products business.

Despite the difficulties facing the petroleum industry in the short-term, governments can legitimately stand by the positive initiatives they have taken to deregulate crude oil and natural gas prices and to improve the fiscal and regulatory regimes. These policies can help the industry acclimatize to the new economic reality of lower crude oil prices.

Although conventional oil exploration in western Canada is the least susceptible of all types of upstream activity to a decline in crude prices, even it is being adversely affected. The governments of producing provinces will be able to maintain high levels of activity only if they reduce their royalties. Accelerating the Petroleum and Gas Revenue Tax phase-out, which under the present regime will disappear only at the beginning of 1989, would be a viable option for the federal government if lower oil prices lead to a significant reduction in exploration activity.

The petroleum industry cannot continue to be a "major engine of economic growth" during 1986 if crude oil prices remain at low levels. However, a potential substitute source of greater economic activity will be all those industries which benefit from lower energy costs.

Your company's strong financial condition puts it in an excellent position to weather the price turbulence and participate in investment opportunities. Dedicated, productive employees combined with strong leadership from its managers and directors, and the continued support of its shareholders will enable Texaco Canada to adjust successfully to the new and challenging times that are ahead for the Canadian energy industry.

Acknowledgements

In closing, I would like to acknowledge the valuable contribution made to your company by a number of people who retired during the year. Howard Lang, who retired in May of 1985, served on our Board of Directors for 19 years, adding an inestimable wealth of good counsel during that time. Norman Taylor, Vice-President of Marketing, Charles Ramsay, Vice-President of Employee Relations and William O'Heran, Vice-President of Texaco Canada Resources Ltd. can proudly claim significant accomplishments in the more than three decades each was associated with this company. On your behalf, I thank them for their dedicated service.

On behalf of the Board of Directors,

James L. Dunlap

James L. Dunlap,
President and Chief Executive Officer

North York, Ontario
March 10, 1986

Energy Resources

Texaco Canada is the largest producer of conventional crude oil and natural gas liquids in Canada. This represents both the company's greatest strength and greatest challenge. Replacing reserves and maintaining production levels are the company's primary objectives in exploration and production. Texaco Canada is meeting this challenge through a diversified strategy comprising seven key elements. They are:

Aggressive western Canadian exploration.

Canadian frontier exploration.

Foreign exploration in select areas.

Application of advanced enhanced oil recovery methods.

Expansion of natural gas liquids extraction capabilities.

Participation in a commercial heavy oil or oil sands project.

Acquisition of reserves by purchase.

These strategies are supported by Texaco Canada's substantial human, technological and financial resources.

Texaco Canada Resources Officers (from left) Senior Vice-Presidents Neal H. Eggen and G. Howard Agnew; President and Chief Executive Officer William A. Gatenby; Vice-President Orville C. Windrem.

Texaco Canada's exploration and production activities, previously managed by Texaco Canada Resources Ltd. (TCRL), a wholly owned subsidiary headquartered in Calgary, Alberta, have been reorganized following the acquisition of Canadian Reserve Oil and Gas Ltd. to form a more efficient business organization. Canadian Reserve was acquired January 2, 1985 from a subsidiary of Texaco Inc. at a cost of $495 million.

Effective February 1, 1986, substantially all upstream operations in the western provinces will be conducted by Texaco Canada Resources, a limited partnership between Texaco Canada Inc. and TCRL.

The exploration and production sector in 1985 contributed $272 million or 81 per cent of total corporate earnings, and was responsible for 38 per cent of total assets at year-end. Capital and exploration expenditures, exclusive of the purchase of Canadian Reserve, were $190 million in 1985 or 71 per cent of the corporate total. This represents an 18 per cent increase over the $161 million spent in 1984 and reflects the favourable investment climate stemming from the Western Accord and provincial royalty changes, and the company's strong commitment to reserves replacement.

Accelerated investment produced a 93 per cent increase in exploration wells drilled, and a six per cent increase in development wells.

In 1985 the company replaced 126 per cent of crude oil and natural gas liquid production, marking the fourth consecutive year this ratio has increased.

Production

Crude Oil and Natural Gas Liquids

In 1985, Texaco Canada's production of crude oil and natural gas liquids averaged 23 400 cubic metres per day, a decline of three per cent from 1984. The reduction was caused by three main factors: prorationing by the Alberta Energy Resources Conservation Board (ERCB) as a result of lower market demand; insufficient pipeline capacity; and the reduced production capability of the company's more mature fields.

Texaco Canada had an average of 920 cubic metres per day of potential liquids production shut in during 1985. Production during late 1985 increased as a result of the ERCB's supplementary sales program which allowed sales of shut-in crude oil (dependent on pipeline capacity) once initial orders were filled. Supplemental sales made by Texaco Canada amounted to 133 800 cubic metres in 1985.

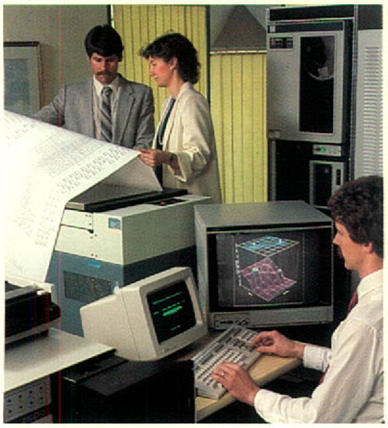
The company anticipates that production in 1986 will continue to be limited by prorationing, pipeline capacity to eastern Canada, and the maturing of existing fields. It is expected that the shut-in problem will be partially alleviated through continued participation in the supplemental sales market.

New and expanded gas plants, notably the Elmworth deep cut facility, helped increase liquid reserves in 1985 by 2.2 million cubic metres. Most of this production is not reflected in 1985 production figures because it was used in enhanced oil recovery projects. Injected materials, which amounted to 608 000 cubic metres in 1985, are largely royalty-paid and will make a substantial contribution to earnings when optimum recovery of crude oil from these projects is achieved.

Natural Gas Production and Sales

Sales of natural gas averaged 4.1 million cubic metres per day in 1985, a 28 per cent increase over the previous year resulting from increased sales to gas exporting companies and the acquisition of Canadian Reserve.

Almost all of Texaco Canada's natural gas production not dedicated to enhanced oil recovery projects is under contract.



Computer graphics capabilities were upgraded significantly in 1985 with the addition of two interactive graphics computers and various high quality graphics output devices. Senior Programmer/Analyst Greg Roy (seated at console) sends graphics output to selected devices such as a slide and film camera (foreground), a high resolution color display, or an electrostatic plotter upon which a seismic weathering and statics diagram is being examined by Senior Programmer/Analyst Jeff Poste and Advanced Explorationist Janet Astle.

Barry Winger, General Superintendent, Gas, and David Ching, Gas Engineer, review a process flow sheet for the planned West Pembina Gas Plant. The plant, slated for completion in late 1987, will process solution gas from enhanced oil recovery projects in the Pembina area of west central Alberta.

Reserves

Texaco Canada replaced 126 per cent of gross liquids production in 1985, marking the fourth consecutive year in which the replacement/production ratio was improved–a feat that has been accomplished in a very cost-effective manner. Sixty-four per cent (6.9 million cubic metres) of the new reserves resulted from the acquisition of Canadian Reserve. Increased gas plant capacity accounted for 20 per cent (2.2 million cubic metres) of new reserves with the balance resulting from enhanced oil recovery, exploration and revisions to previous estimates.

In 1984, 90 per cent of production was replaced as a result mainly of the Bonnie Glen ethane liquefaction facilities and various enhanced oil recovery projects. In 1983, liquids reserves replacement was 74 per cent, largely because of the Wizard Lake Tertiary Miscible Flood which added 3.2 million cubic metres. Improved liquids recovery and the efficient performance of the Wizard Lake Miscible Flood project were the primary contributors to replacement of 44 per cent of liquids production in 1982.

Natural gas reserves increased by 22 per cent in 1985, with the acquisition of Canadian Reserve providing most of the increase.

Texaco Canada's reserves replacement strategy does not depend on a single major approach but comprises seven diverse elements: western Canada exploration, frontier exploration, foreign exploration, enhanced oil recovery, natural gas liquids extraction through gas processing, heavy oil and oil sands projects, and acquisitions. These elements are discussed in detail in the following pages.

The company intends to replace at least half of its liquids production through a combination of western Canada exploration, natural gas liquids extraction and enhanced oil recovery. The other four elements are intended to replace the remaining 50 per cent of production.

Element One:
Western Canada Exploration

Texaco Canada continues to increase its exploration efforts in western Canada in the belief that substantial quantities of medium to light crude remain to be found. Current royalty incentives encourage such exploration although discoveries generally occur in difficult to identify pools which require sophisticated and intensive exploration. However, it is the company's opinion that its western Canadian exploration program can make a significant contribution to reserve replacement in the short term.

During 1985, Texaco Canada participated in 123 exploratory wells in western Canada resulting in 54 oil wells and 12 gas wells. An additional 50 wells were awaiting completion or final evaluation at year-end.

The company's petroleum search in western Canada is directed toward three play types–medium and light crude oil, conventional heavy oil, and natural gas. Its exploration philosophy is to develop new play concepts over large geographic areas throughout western Canada. These broad play trends are ranked on the basis of risk and potential reserves and the top prospects are evaluated by aggressive seismic, drilling and lease acquisition programs.

In 1985 this approach led to major emphasis on Devonian Reef, Cretaceous Sandstone and structural / stratigraphic Carbonate plays in Alberta. The program met with considerable success, particularly in the search for conventional oil.

Devonian Leduc Reefs (see map) have been highly productive exploration targets in western Canada since the 1940s. New technology has led to the discovery in recent years of several significant pools undetected by previous exploration activity.

Over the past three years, Texaco Canada has conducted 2210 kilometres of regional proprietary seismic surveys over established Devonian Leduc Reef trends in southern and central Alberta. Prospects have been further evaluated by detailed conventional seismic and sophisticated three dimensional seismic programs. In 1985 this exploration program led to the drilling of three exploratory wells, resulting in one oil and one gas-condensate discovery. Further delineation of this play will continue through 1986 and beyond.

The Pembina area of west central Alberta is an established producing area where Texaco Canada has extensive land holdings. During 1985, the company participated in 20 exploratory wells in this area targeted at Cretaceous oil and gas-condensate prospects. Eight of the wells were oil discoveries and three were gas finds.

In northern Alberta, Texaco Canada continued to explore for oil in Devonian Wabamun structural-stratigraphic traps. In the Eaglesham area, the company shot proprietary seismic programs, acquired acreage and participated in seven exploratory wells which resulted in four oil discoveries. Texaco Canada also participated in detailed seismic surveys in the Virgo area and in an exploratory well, which successfully delineated an oil pool. The target in the Virgo region is Devonian Keg River reefs.

Texaco Canada became a major participant in exploration for conventional heavy crude oil along the Alberta-Saskatchewan border area following its acquisition in 1985 of Canadian Reserve, with a working interest in more than 100 000 hectares. Although heavy crude is more difficult to recover than the lighter oils prevalent elsewhere in western Canada, it occurs in shallow reservoirs which provide compensating economies in drilling costs. In addition, opportunities exist for improved recovery through thermal stimulation.

Texaco Canada is participating actively in heavy oil plays centred on the Cretaceous Mannville Group sandstones and extending to the deeper Devonian Bakken Formation. The company participated in the drilling of 21 exploratory heavy oil wells in 1985, resulting in 17 discoveries.

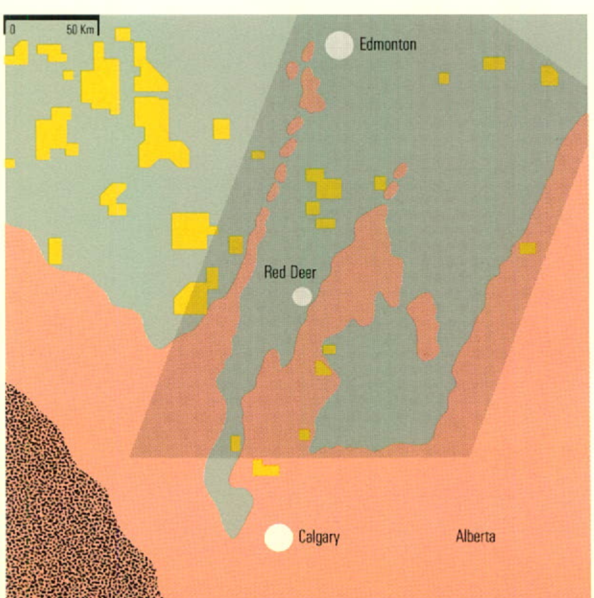
Texaco Canada began exploration in northeastern British Columbia in 1945 and has participated in the discovery and development of several major oil and gas pools in the province. The company in 1985 continued to drill shallow oil prospects in British Columbia, particularly in the Desan area, with modest success.

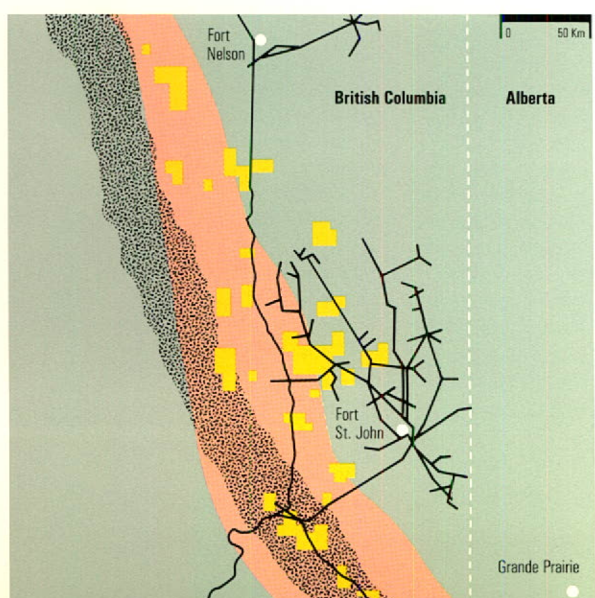
Devonian Leduc Reef Play

- Texaco Interest Lands
- Devonian Leduc Reef
- Concentration of Activity

British Columbia Foothills Play

- Texaco Interest Lands Along Play
- Foothills Play
- Gas Pipelines





The reduction of various government restrictions on the export of natural gas has encouraged the company to actively explore for natural gas in an effort to find additional reserves.

The company believes major opportunities exist in British Columbia for the development of large, highly productive natural gas fields. It has conducted extensive proprietary seismic programs in the British Columbia foothills and has increased its landholdings in the area (see map page 6).

The company believes discoveries made in 1985 have the potential to add 1.93 million cubic metres of liquid reserves when fully developed.

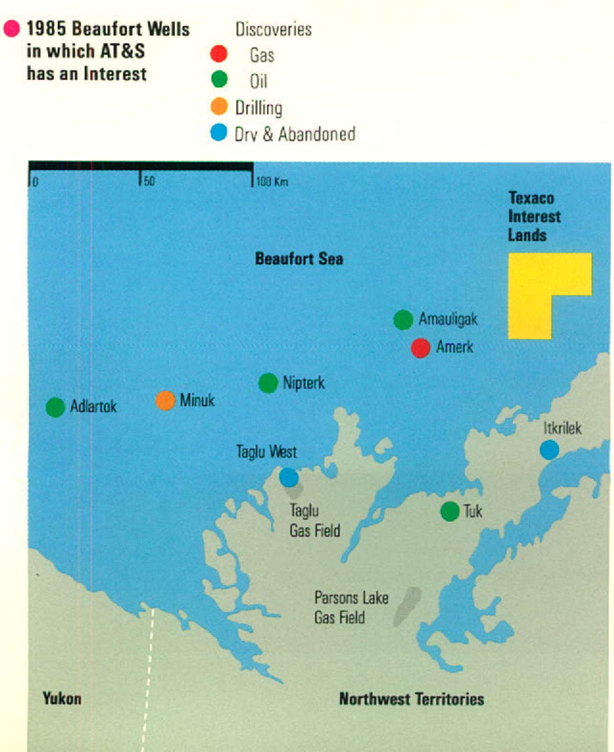
Element Two:
Frontier Exploration and Production

Frontier areas could contribute large reserves over the long term but exploration and development are high risk and costly. Texaco Canada's frontier activity has been tempered by these factors and by unfavourable government policies and regulation concerning offshore resources. However, the Atlantic Accord and new federal energy policies, settlement of the United States/Canada boundary dispute off the east coast, and some recent encouraging discoveries, are prompting the company to re-evaluate its position with respect to frontier activities.

AT&S

Texaco Canada has conducted its exploration on federally administered lands during the past two years primarily through AT&S Exploration Ltd. (AT&S), a joint exploration company created in 1983. Texaco Canada Resources Ltd. holds 25 per cent of the voting shares in AT&S.

AT&S, with 75 per cent Canadian ownership, qualified for maximum grants under the Petroleum



Oil and Gas Rights December 31	**1985** Gross	**Net**	1984 Gross	Net
Canada	Thousands of Hectares			
Alberta	**1368**	**755**	969	590
Other Western Provinces	**682**	**316**	217	146
Quebec Onshore	–	–	120	120
Eastern Canada Offshore	**2629**	**1617**	3644	2007
Beaufort Sea	**140**	**61**	106	53
Other	**748**	**85**	151	103
Total Canada	**5567**	**2834**	5207	3019
International				
Brazil	**13286**	**6643**	16608	8304
Peru	**1000**	**212**	1000	212
Guatemala	–	–	198	33
Guinea Bissau	**450**	**76**	450	76
Total International	**14736**	**6931**	18256	8625
Total	**20303**	**9765**	23463	11644

Drilling Activity	**1985** Gross	**Net**	1984 Gross	Net
Exploratory Wells				
Oil	**54**	**31.1**	21	9.5
Gas	**12**	**5.6**	12	4.3
Dry	**69**	**34.7**	37	17.5
Total Exploratory Wells	**135**	**71.4**	70	31.3
Development Wells				
Oil	**159**	**28.7**	166	38.3
Gas	**15**	**8.2**	3	1.8
Dry	**13**	**4.5**	7	1.2
Total Development Wells	**187**	**41.4**	176	41.3
Total Wells	**322**	**112.8**	246	72.6

Gross Production of Crude Oil and Natural Gas Liquids	**1985**	1984
Crude Oil	Thousands of Cubic Metres Daily	
Alberta		
Bonnie Glen	**7.4**	8.7
Wizard Lake	**4.8**	5.8
Pembina	**4.3**	3.5
Swan Hills	**1.1**	1.2
Other	**2.5**	2.2
Total Alberta	**20.1**	21.4
Saskatchewan	**.7**	.2
Other Provinces	**.3**	.2
Total	**21.1**	21.8
Natural Gas Liquids	**2.3**	2.3
Total Crude Oil and Natural Gas Liquids	**23.4**	24.1

Estimated Gross Proved Reserves	1985	1984	1983	1982	1981
Crude Oil and Natural Gas Liquids	Millions of Cubic Metres				
January 1 Reserves	**64.0**	64.9	67.1	71.8	81.6
Revisions	**0.4**	0.2	1.4	2.2	(2.3)
Enhanced Recovery	**0.7**	2.4	4.5	–	–
Extensions, Discoveries and Other Additions	**2.7**	5.3	0.4	1.5	1.1
Acquisitions	**6.9**	–	–	–	–
Total Reserve Changes	**10.7**	7.9	6.3	3.7	(1.2)
Gross Production	**(8.5)**	(8.8)	(8.5)	(8.4)	(8.6)
December 31 Reserves	**66.2**	64.0	64.9	67.1	71.8
Replacement Percentage	**126%**	90%	74%	44%	–
Natural Gas (1)	Billions of Cubic Metres				
January 1 Reserves	**51.4**	62.8	63.3	65.2	60.9
Revisions	**0.1**	(11.0)	(0.4)	(1.1)	1.1
Enhanced Recovery	**0.1**	0.3	0.6	–	–
Extensions, Discoveries and Other Additions	**0.3**	0.6	0.7	0.8	4.7
Acquisitions	**12.4**	–	–	–	–
Total Reserve Changes	**12.9**	(10.1)	0.9	(0.3)	5.8
Gross Production	**(1.5)**	(1.3)	(1.4)	(1.6)	(1.5)
December 31 Reserves	**62.8**	51.4	62.8	63.3	65.2
Replacement Percentage	**860%**	–	64%	–	387%

(1) Prior to December 31, 1984 estimates of the Corporation's natural gas reserve quantities were reported on a "raw" gas basis and included the volume of the percentage of natural gas liquids which may be removed at locations beyond lease and/or field separation facilities. Effective December 31, 1984 the Corporation's estimates of natural gas reserves are on a "dry" gas basis and account for shrinkage resulting from anticipated natural gas liquids recovery through existing facilities.

Incentives Program (see page 11). AT&S participated in 21 wells during 1985 (nine of which showed oil and/or gas), and plans to participate in 24 wells in 1986, most of them in northern Canada.

The Adlartok P-09 well in the Beaufort Sea and the Tuk J-29 well on the Tuktoyaktuk Peninsula tested significant quantities of hydrocarbons. Follow-up drilling to these wells and to the significant 1984 Beaufort Sea discovery, Amauligak J-44, is continuing in 1986. Recent testing at Amauligak I-65 indicates potential reserves for the field in the range of 110 to 130 million cubic metres. AT&S will increase its current 6.2 per cent working interest in the structure to 10 per cent by participating in the next well and has an option to increase its interest to 12.5 per cent by participating in a third well.

Venture

Texaco Canada holds an 18 per cent interest in the Venture gas field, offshore Nova Scotia.

To date, the results of the ongoing exploration and delineation programs have been disappointing. During 1985, three wells in which the company has an interest, West Venture C-62, West Venture N-91 and West Olympia O-51, completed drilling and were abandoned.

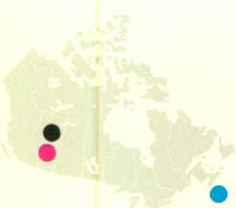
Adequate reserves to support the development of the Venture project have not yet been defined. Preliminary discussions with other non-Venture operators in the area have been initiated, although further drilling is required to define their reserves. Texaco Canada is nevertheless optimistic that the development of the Venture area on a regional basis will be attractive.

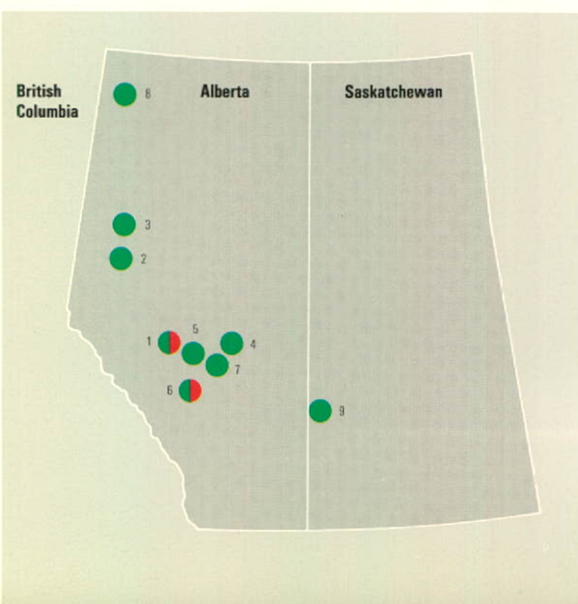
Venture participants have applied to the National Energy Board for the export of Venture natural gas to the United States. A hearing on the project is expected after further information on reserves is available.

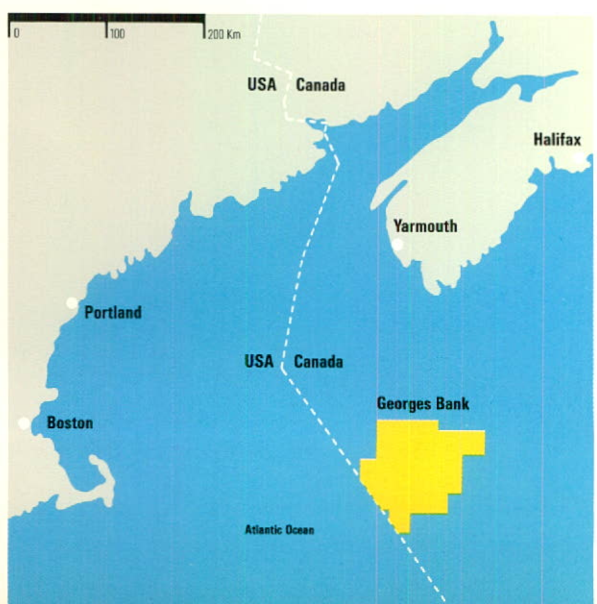
Texaco Significant Discovery Areas 1985
Gas
Oil

(1) Pembina
(2) Cindy
(3) Dunvegan
(4) Bonnie Glen
(5) Violet Grove
(6) Medicine River
(7) Knob Hill
(8) Virgo
(9) Court

Georges Bank Land Holdings







Georges Bank
Most of the land Texaco Canada held under former exploration permits in the Georges Bank boundary dispute area falls on the Canadian side of the redrawn boundary as a result of a decision reached by the International Court of Justice with respect to the Gulf of Maine Case. Seismic surveys on this 100 per cent owned 883 000 hectare block have yielded encouraging results. The area is close to northeastern United States markets and is prospective for both oil and gas. The company is currently negotiating an exploration agreement with the federal government and hopes to initiate a drilling program late in 1986 or in early 1987.

Bent Horn
An ice-strengthened tanker carried the first shipment of Canadian Arctic oil in August 1985 from the Bent Horn field in which Texaco Canada acquired a 3.3 per cent interest with its purchase of Canadian Reserve. Nearly 16 000 cubic metres were delivered to Montreal and a similar volume is expected to be shipped in 1986.

Element Three:
Foreign Exploration
Foreign exploration offers the potential of adding crude oil reserves at a reasonable cost over the medium term.

In Brazil, seismic operations are being conducted on the Marajo Block at the mouth of the Amazon River. Early results are encouraging and drilling could begin late in 1987. Texaco Canada holds a 50 per cent interest in about 13 million hectares.

The Mahuaca Number One well in Peru was a dry hole. Three exploratory wells completed in Guatemala in 1985 failed to discover commercial quantities of oil. No further exploration is currently planned for either block, but the company continues to seek other foreign opportunities.

Element Four:
Enhanced Oil Recovery
Enhanced oil recovery continues to be a large, cost effective source of reserve additions for Texaco Canada.

Seventy-six per cent of the company's reserves are under some form of enhanced recovery–waterflooding, miscible flooding or steamflooding.

One of Texaco Canada's major fields, Wizard Lake, has been under enhanced recovery since 1969 and 21 of the company's 30 West Pembina pools, discovered in the late 1970's, are being subjected to either water floods or miscible floods.

Six enhanced oil recovery projects implemented in 1985 ultimately will add 2.6 million cubic metres of crude oil to Texaco Canada's reserves. In 1985, these projects accounted for 0.7 million cubic metres of reserves added. A miscible flood has been introduced at Swan Hills in north-central Alberta, which is expected to provide a total of 1.6 million cubic metres of reserves in 1986.

Waterfloods were implemented in two of the pools in the Pembina area in 1985.

Eight projects planned for 1986 are expected to add 1.1 million cubic metres to reserves next year, plus an additional 2.1 million cubic metres in succeeding years. Other potential projects have been identified for implementation beyond 1986.

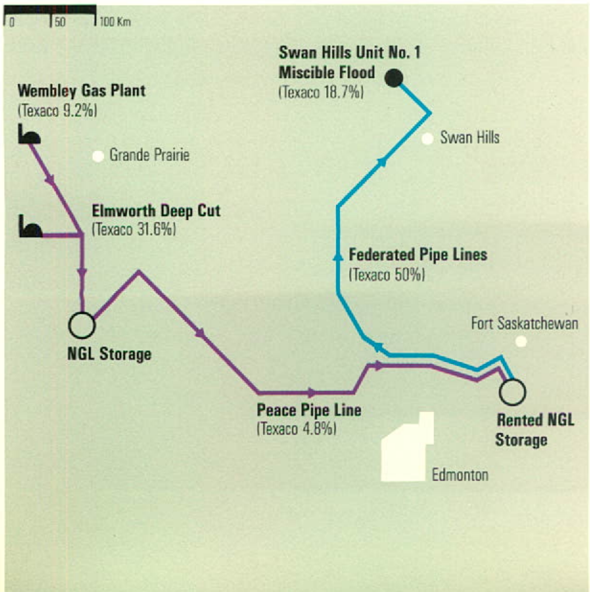
The company also is studying the possibility of implementing an enhanced recovery scheme in the Bonnie Glen field. This scheme could increase the ultimate recovery of oil from the currently anticipated 68 per cent to the 80 per cent range which would increase reserves by an additional 10 million cubic metres of crude oil.

Element Five:
Natural Gas Liquids Extraction
Natural gas processing is very important to the company because of the additional reserves provided by the resulting natural gas liquids and the fact that the liquids and natural gas can be used for enhanced oil recovery.

In 1985, the addition of facilities for the extraction of ethane and heavier natural gas liquids at the Elmworth Gas Plant near Grande Prairie, Alberta, added two million cubic metres to liquids reserves. The extracted natural gas liquids (NGL's) are being used in the Swan Hills miscible flood, which itself will add 1.6 million cubic metres to reserves in 1986. The Elmworth NGL's are transported by pipeline to storage at Fort Saskatchewan and then through the Federated Pipe Lines Ltd. pipeline (in which Texaco Canada owns a 50 per cent interest) to Swan Hills (see map at left).

Two other plants in which Texaco Canada has an interest, the Progress and Brazeau River plants, were completed during 1985. They added 300 000 cubic

Texaco Natural Gas Liquids Supply System for Swan Hills Miscible Flood Project



metres of liquids reserves, and 127 cubic metres of daily liquids production capability to the company.

The company will continue to add to its gas processing and liquids extraction capability in 1986. Two facilities in which Texaco Canada has an interest are scheduled to begin operations in 1986. The Wembley gas cycling facilities in which Texaco Canada has a 9.2 per cent interest will be producing more than 200 cubic metres per day of liquids by June 1986. The 60 per cent owned Waterton gas gathering system will provide additional gas sales and liquids and sulfur production. Planning is underway for a plant in the Pembina area of west-central Alberta to process solution gas from enhanced oil recovery projects.

At year-end, 1985, Texaco Canada had an interest in nine operated and 57 non-operated gas plants.

Element Six:
Heavy Oil and Oil Sands

Texaco Canada intends to achieve a significant heavy oil and oil sands presence through a two-fold strategy: first, intensive exploration of existing land holdings to delineate potential reserves and to evaluate recovery processes for identified resources; second, active pursuit of farm-ins or acquisitions. The company has given high priority to its goal of participating in a commercial oil sands project.

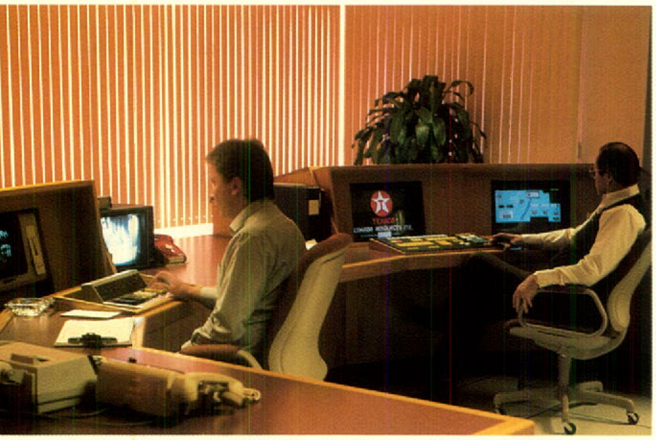
The purchase of Canadian Reserve Oil and Gas Ltd. in 1985 provided Texaco Canada with a heavy oil production base, interests in heavy oil properties and technical expertise in the production of heavy oil. Production from the wholly owned Lone Rock heavy oil steam pilot project near Lloydminster, Saskatchewan began during 1985. Initial results of 100 cubic metres per day have been encouraging, and the potential for expanding the project is under review. The company's total heavy oil production in 1985 amounted to 730 cubic metres per day.

On Texaco Canada's Frog Lake lease in the Cold Lake area of east-central Alberta, four corehole wells were drilled early in 1985 and a seismic program was conducted. A further seven-well evaluation program was completed early in 1986. Results will be evaluated following geological review and primary production testing to determine if additional wells and/or steam stimulation tests are warranted. The program is evaluating the potential for commercial recovery operations. A decision is not expected until after the completion of any steam stimulation testing.

Texaco Canada has phased out operations in the first two patterns of wells drilled at its Fort McMurray Pilot Project in the Athabasca oil sands area of northeastern Alberta. Production and data gathering are continuing in a third pattern which includes three long, parallel, horizontal wells drilled in 1980-81 to test recovery from horizontal drain holes. Research is concentrated on the development and application of in-situ recovery techniques to make bitumen flow while leaving the sand in place.

The Fort McMurray Pilot Project has provided Texaco Canada with information and techniques for application on other properties where the depths of the overburden above the oil sands deposits do not allow economic bitumen recovery by open pit mining procedures. At the 10 400 hectare Hangingstone lease, south of Fort McMurray, for instance, the company has initiated a 25 well drilling program scheduled for completion in the first quarter of 1986 as a first step in assessing the potential for a pilot project.

No reserves have been attributed to the company's oil sands deposits because no portion of the bitumen has yet been shown to be economically recoverable.



Operators Paul Malloy and Dennis Erickson at the Pipeline Control Centre in Edmonton control the flow of materials through pipelines as far away as 145 kilometres. The Centre can monitor volume, divert material from one line to another, shut in specific batteries or close down the entire system.

Element Seven:
Acquisitions

The company's strong financial position enables it to increase its reserves through economically viable acquisitions. The purchase of Canadian Reserve Oil and Gas Ltd. was the major contributor to Texaco Canada's reserves replacement in 1985, adding some 6.9 million cubic metres of liquids and more than 12 billion cubic metres of natural gas. Opportunities for further acquisitions are being evaluated.

The foregoing seven key strategic elements provide Texaco Canada with a wide range of opportunities to achieve its goals of maintaining production and replacing reserves. The company's expanded investment program produced positive results in 1985 and should continue to contribute to the profitability of the resource sector.

1985 Governmental Policy Changes

Several policy changes introduced by the federal and some provincial governments during 1985 significantly improved the operating and economic environment for the Canadian petroleum industry.

Atlantic Accord
The Atlantic Accord reached in February between Newfoundland and the federal government established a long-term agreement on the joint management of offshore oil and gas exploration and development by the two jurisdictions. Texaco Canada's interests at Greenbank (100 per cent in 37 000 hectares) and at Gander (28 per cent in 761 000 hectares) are within the area covered by the Atlantic Accord. A well to test a large structure extending onto Greenbank is planned for 1986.

Western Accord
The Western Accord between the Canadian government and the governments of the producing provinces, Alberta, Saskatchewan and British Columbia, was announced in March. It included provision for the deregulation of crude oil pricing and export volumes, effective June 1; gradual phaseout of the Petroleum and Gas Revenue Tax (PGRT) on existing wells by 1989; and elimination of Petroleum Incentive Program grants effective March 31, 1986 (with grandfathering of commitment wells to the end of 1987).

The price for much of Canada's conventional oil production was regulated before June 1 at a level below market value. This included almost 65 per cent of Texaco Canada's oil production, so the deregulation of pricing was advantageous for the company. However, falling world oil prices have offset many of the anticipated benefits of decontrol.

The phaseout of the PGRT did not begin until January 1986, so it did not affect 1985 earnings. The PGRT amounted to $171 million in 1985. The positive effects of the PGRT reduction will be felt during 1986, but will not have their greatest impact until 1989 when the tax will be completely eliminated. The PGRT phaseout will save Texaco Canada an estimated $500 million over the next five years.

The company has been conducting much of its frontier exploration through farm-outs, particularly to AT&S Exploration Ltd. because of the discriminatory nature of the Petroleum Incentive Program (PIP) grants. Based on its level of Canadian ownership, Texaco Canada qualified only for the minimum level of grants, putting it at a competitive disadvantage to companies receiving higher grants.

Provincial Changes
The Western Accord was followed in June by changes to the Alberta royalty and incentives systems. Marginal royalty rates on oil and gas were reduced effective August 1, 1985, with further reductions scheduled for the next two years. Incentive grants were eliminated and replaced by success-oriented royalty holidays. The company's Crown royalty payments for the second half of 1985 were three per cent lower than they would have been without the changes. Future reductions in Alberta Crown royalties will yield additional net revenue for investment.

The Saskatchewan government subsequently announced a continuation of its royalty holidays until the end of 1986, and the British Columbia government introduced royalty holidays on both exploratory and development oil wells. Texaco Canada has planned an increase in 1986 in all its B.C. activities–lease acquisitions, seismic, wildcat drilling and infill drilling.

Frontier Energy Policy
The Canadian government announced its new frontier energy policy, applicable to lands under federal jurisdiction, on October 30, 1985. The Petroleum Incentives Program will be replaced by an exploration tax credit which does not discriminate on the basis of Canadian ownership or exploration location and which rewards success rather than mere activity. While the value of the tax credit is somewhat less than the value which PIP's had to the company, the removal of the discriminatory provisions places Texaco Canada on an equal, competitive basis with other companies.

The retroactive 25 per cent Crown share or "back-in" available to the Government of Canada in all oil and gas interests on federally administered lands was eliminated. A competitive bidding process for the awarding of exploration rights on federal lands and a profit sensitive royalty regime were included.

As a result of the new provisions for exploration and production on frontier lands, combined with the previously discussed termination of the Petroleum Incentives Program, Texaco Canada is planning to increase its direct participation in frontier exploration.

Agreement on Natural Gas Markets and Prices
An agreement was announced in October between the federal government and the producing provinces on deregulation of the Canadian natural gas industry and changes in export policies. It permits Canadian export prices for natural gas to be based on the regional domestic gas price at the point of export rather than on the Toronto city gate price, thereby allowing Canadian exports to compete more effectively in the United States market. Negotiated, market-oriented domestic gas prices will be introduced by November 1, 1986. The revised export policy should stimulate additional exploration for and delineation of natural gas reserves.

Petroleum Products

The refining and marketing industry in Canada has been subjected to an unprecedented series of changes that have affected the fundamental nature of the business. A five-year decline of almost 25 per cent in the demand for petroleum products in Canada was followed in 1985 by deregulation, continued volatile market pricing, and the establishment of commodity markets for crude oil and products, all of which contributed to an environment of uncertainty.

Only marginal growth in demand is expected during the rest of this decade. Texaco Canada's primary objective of earning a reasonable return on invested capital demands that yesterday's attitudes be replaced with strategies and practices suitable for changing conditions.

Texaco Canada has responded with many productivity improvement measures, including refinery closures, retail network rationalizations, and the computerization of operations. This trend continued in 1985 with major investments at the Nanticoke refinery, a new wholesale distribution system, and the introduction of a profit centre concept with improved management information systems.

These strategies helped move Texaco Canada's petroleum products operations solidly into the black in 1985 and will continue to enhance profitability and secure the company's competitive position in the years ahead.

From left, Colin C. Wild, General Manager, Supply and Distribution; Stephen T. O'Farrell, Vice-President, Marketing; Stuart J. Walker, Senior Vice-President; Leslie F. Tye, Vice-President, Refining.

Texaco Canada Inc. is a national marketer of refined petroleum products with more than 2,300 retail locations from coast to coast. This network is supplied by company-owned refineries in Ontario and Atlantic Canada and by processing agreements with other refiners in Quebec and western Canada.

The Petroleum Products sector encompasses 48 per cent of total corporate assets. It experienced a turnaround in 1985 as improved margins and the effects of productivity improvement programs produced profit of $39 million compared to a $3 million loss in 1984–a positive swing of $42 million. These Petroleum Products earnings accounted for 12 per cent of the corporate total in 1985.

Capital expenditures amounted to $77 million in 1985. They are expected to increase in 1986 with investments in the Nanticoke refinery and service station upgrading accounting for most of the spending. The company's objective is to increase returns to an acceptable level by establishing itself even further as a lean, efficient, competitive supplier of petroleum products. Texaco Canada will continue to analyze all aspects of the business and institute the changes necessary to ensure that assets are deployed and operations carried out in a manner consistent with the requirements of a changing business environment.

Marketing

The rethinking of the company's Marketing strategies affected every facet of operations and culminated at year-end in major structural changes in the Marketing Department itself. Fifteen Division Profit Centres were created across Canada January 1, 1986 and charged with the responsibility for reducing operating costs and maximizing revenues. These 15 Profit Centres, which act as tactical business units, replace three Regions, 11 Divisions and 27 Districts. They are responsible for all marketing activities within their areas including the execution of marketing plan strategies for all major classes of trade–Retail, Wholesale and Commercial.

The company's Computer Information and Corporate Services Department is supporting the marketing effort with personal computers and on-line terminals at all Profit Centres and other key locations across the country. This will increase the information available to field personnel and improve financial accountability throughout the organization. These systems will provide up-to-date information and assist field supervisors with key business decisions.

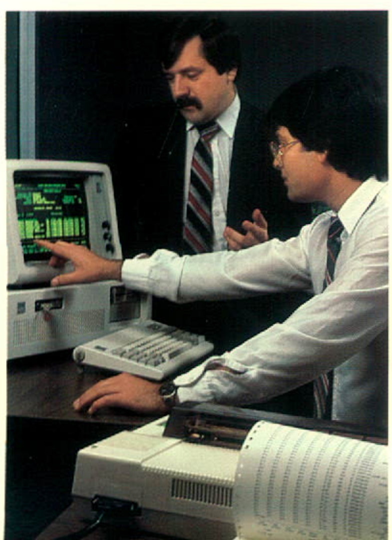
The efficiency of the company's product distribution system also improved during the year, enabling the Marketing Department to compete more effectively by delivering products at lower cost. Major savings were realized by using outside haulers exclusively at six major product terminals across Canada–Victoria and Vancouver in British Columbia; Port Credit, Ontario; Rimouski and Chicoutimi in Quebec; and Charlottetown, P.E.I.

Retail

The company's "Retail" segment is responsible for selling petroleum products through retail facilities and accounts for approximately 41 per cent of refined product sales. The rationalization of the service station network continued in 1985 with the closing of many low volume outlets with high operating costs and the opening of 38 high volume System 2000 service stations through major renovations or new construction. The number of retail outlets at year-end totaled 2,341, a net reduction of 156 outlets during the year.

The System 2000 outlets are part of a total marketing strategy designed to strengthen Texaco Canada's marketplace position to the year 2000 and beyond. The System 2000 stations are attracting new customers with their bold graphics and convenient "family of buildings" concept that provides high volume pump islands, food stores, and car washes or service bays. The System 2000 graphics also are building additional traffic when applied to conventional service stations.

The attractive new "System 2000" service stations are building additional business with their modern pump islands, food marts, and car washes or service bays.



Jerry Seguin, Administrator, Wholesale Marketing (left) and Ben Sial, Analyst Programmer, review reports of Wholesale Marketer program.

The company had 50 System 2000 stations in operation at year-end, with another 50 scheduled to open during 1986.

A project team has completed a study and pilot test of the Texaco Retail Automated Marketing Systems (TRAMS), which eventually will link electronically 1,500 high volume retail outlets across Canada to a central computer.

It will capture information on service station credit card sales electronically, thereby eliminating an enormous paperwork burden. It also will position Texaco Canada to take advantage of all future payment methods and evolving technology in service station automation, and will provide the capability for credit authorization and an inventory control system. Other features will provide for future use of card-activated pumps, debit-card payment systems, and environmental protection devices. TRAMS, when fully implemented, will achieve a net reduction of working capital and a large reduction in operating expenses.

The company reached agreement with American Express Canada Inc. during 1985 to accept the American Express card at Texaco Canada retail locations. The agreement is helping Texaco retailers attract a new segment of motorists to their locations.

Wholesale

"Wholesale" operations account for much of the company's sales of petroleum products throughout rural and small urban areas of Canada, and represent approximately 31 per cent of total volume. Major changes to the wholesale distribution system begun in 1985 included the introduction of the Texaco Wholesale Marketer Program, a marketing strategy that creates a more efficient, entrepreneurial and cost effective network.

Wholesale Marketers are customers who buy Texaco products for resale under the Texaco brand in a given area. They generally serve small businesses, some Texaco retailers and agricultural accounts, and a variety of commercial accounts, particularly in outlying areas where Texaco Canada does not have major distribution terminals.

The Wholesale Marketers will be supported by a newly developed computerized system designated as TAWS (Texaco Automated Wholesale System). It consists of personal computers linked to Texaco Canada's mainframe computer and performs order entry, invoicing, accounts receivable, managerial information reporting, inventory control, and equipment control operations. A pilot project proved successful during 1985 and complete implementation of the system is expected by the end of 1986.

Commercial

"Commercial" marketing activities involve the company's sales of petroleum products to industrial customers such as manufacturers, mines, and trucking fleets and account for roughly 28 per cent of sales. A major activity has been the expansion of Texaco Cardlock, a national network of electronically controlled card-activated fuelling facilities which offers fleet operators such benefits as electronic record keeping and improved security. The company had 28 Cardlocks in operation at year-end at strategic points across Canada.

Lubricants

The establishment of a Lubricant Division profit centre improved the profitability of this group of products through closer coordination of all associated activities. The reorganization established a vertically integrated profit centre to optimize all operations from the acquisition of raw materials to the disposition of finished products. The profit centre concept ensures that all functional areas contribute to the generation of improved earnings.

Refining

Texaco Canada was one of the first Canadian companies to bring refining capacity into line with the falling demand for products by closing three aging refineries–Port Credit in 1979, Montreal in 1982, and Edmonton in 1984. Today the two remaining refineries at Halifax and Nanticoke are operating at essentially full capacity.

The remaining challenge–after refining capacity was balanced with product demand–was cost reduction. Various projects were launched to reduce energy consumption and other operating costs and to improve yields.

A program to computerize refinery control processes at Nanticoke refinery was being completed at year-end. It enables the plant to increase the amount of valuable light products, such as gasoline and distillate, that can be made from each barrel of crude oil. The computerized instrument system also increases energy efficiency by continually monitoring refining processes and adjusting them to optimum levels.

Also completed at Nanticoke in 1985 was a two-year program to reduce energy costs by replacing steam turbines with electric motors.

Improvements in energy efficiency and product yields are producing savings at Nanticoke at the rate of about $5 million per year. Similar improvements at the Halifax refinery are yielding savings of approximately $1.5 million per year.

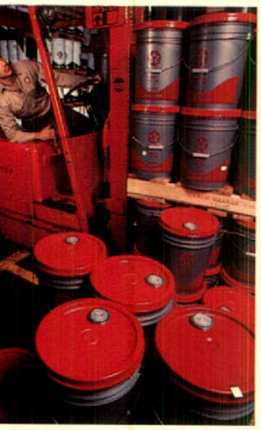
The company's Board of Directors in 1985 approved an $80 million program of three major projects at the Nanticoke refinery designed to further improve the refinery's operating efficiency and to increase its capability to produce lead-free gasoline.

The first project, which will substantially increase the plant's ability to produce lead-free gasoline, involves the installation of a continuous catalyst regeneration system on the catalytic reformer. This project will be completed in 1986.

The second project, which will increase the recovery of propane and butane from refinery fuel gases, also includes a number of energy conservation improvements. These will reduce steam consumption and ensure the proper balance between the production and the demand for steam in the refinery.

The third project will recover heat normally lost in cooling processes through the installation of heat exchange equipment on the crude and vacuum units. The vacuum unit also will be modified to reduce its output of heavy fuel oil and to increase the production of feed stock used for the manufacture of gasoline and heating and diesel fuels.

The three projects, which will all be completed by the end of 1987, will reduce costs by about $25 million a year. The program represents the largest capital investment by the Refining Depart-



Anthony Timpano, Fork Truck Operator, stores 20-litre lubricant containers at Toronto Terminal. The vertically integrated Lubricant Division profit centre maximizes the efficiency of all operations involving lubricant products.

From left, Technicians Don Noseworthy, Laurel Rusling and Gerry Branderhorst plan maintenance schedule for the fluid catalytic cracking unit at Nanticoke Plant.

ment since the Nanticoke refinery was built in the mid-1970s at a cost of $486 million.

At Halifax Plant, the construction of a 32 000 cubic metre storage tank with floating roof was completed at year-end. This, together with the installation of a floating roof in an existing 24 000 cubic metre tank, has improved the plant's flexibility in inventory product handling.

Supply and Distribution

The deregulation of the petroleum industry in Canada, effective June 1, 1985, removed taxes on both imported and exported crude oil and petroleum products and cancelled subsidies on movements of crude oil east of Montreal, allowing supply decisions to be made solely on the basis of logistics and market economics.

The marketplace now determines Canadian crude oil prices and most fluctuations occur in relation to United States crude prices set on the Chicago market. This new market environment has increased the importance and use of sophisticated computer models in the development of operational strategies.

These models evaluate crude feedstocks, optimize refinery operations, minimize distribution costs to major supply points, and evaluate market opportunities.

For example, the computerized Texaco Inventory Management System (TIMS) monitors inventory levels at refineries and major terminals and traces trends which can be acted upon to maximize opportunities and minimize costs. More than 200 000 cubic metres were removed from inventory during the year and a corresponding reduction in working capital requirements was realized.

The computer models also enabled the company to use excess capacity at its Nanticoke refinery to complete several product trades and to generate export sales amounting to 550 000 cubic metres of crude and 320 000 cubic metres of products in 1985. The product exports were primarily surplus from Nanticoke refinery sold to U.S. customers at Great Lakes ports.

Long-term supply agreements with other refiners continued to provide operational savings and reduced inventory levels.

A project team studied the company's downstream product distribution system during the year and substantial savings are expected upon implementation of their recommendations. These include the development of a more flexible costing system, the development of a computer distribution model for evaluating distribution strategies, the initiation of a profit centre reporting system, and improvements to existing computer systems.

The specialty chemicals sector arranged for the manufacture of additional polyol (a plastics feed stock) in Canada in late summer. Overall, the division sold 797 000 cubic metres of primary petro-

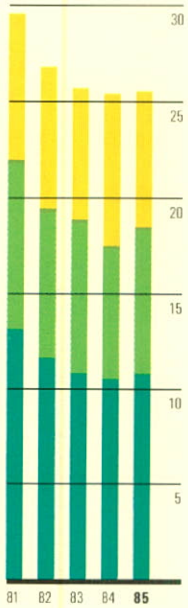
Technician Don Mousseau inspects new 15,000 horsepower electric motor at Nanticoke Plant's catalytic reforming unit. The motor, which replaced a steam turbine, helps reduce operating costs by improving energy efficiency.

An $80 million upgrading program is underway at Nanticoke Plant to improve its operating efficiency and to increase its capability to produce lead-free gasolines. The projects represent the largest Refining Department capital investment since the refinery was built near Lake Erie in the mid-1970s.

chemical products and natural gas liquids during 1985 and contributed $9 million dollars to earnings before income taxes.

The company's supply operations in 1985 involved the transportation of an average of 45 100 cubic metres of crude oil and petroleum products daily, compared with 42 600 cubic metres daily in 1984. This total volume included the movement of 23 100 cubic metres of finished products daily to customers in company-owned and leased vehicles and ships or in equipment owned by outside haulers. The crude oil and natural gas liquids needed by the company in its refining and supply operations required the transportation by pipelines, vessels and other carriers of 22 000 cubic metres daily.

Petroleum Product Sales
Thousands of cubic metres daily
Other products
Middle distillates
Gasoline



Supply Agreements
Texaco Canada's supply agreements with other marketing/refining companies are beneficial and necessary because of the technology and economics of refining and distribution. In Canada, as elsewhere, petroleum refiners commonly buy refined products from one another, exchange them with one another, and process crude oil for one another.

The long-term supply agreements which the company entered into in 1984 with Gulf Canada Limited provided operational savings through reduced transportation costs and lower inventory levels. Obvious savings were realized by having Gulf refineries provide Texaco Canada with products in areas remote from Texaco refineries. Similarly, Gulf realized savings by having its Ontario product requirements supplied through Texaco's Ontario refinery.

The assumption of the Gulf reciprocal agreements by Petro Canada has resulted in Petro-Canada now refining for Texaco Canada in Montreal. Gulf Canada continues to process crude for Texaco Canada at Edmonton.

Petro-Canada also provides a product terminal operation for Texaco Canada at a former Gulf Canada facility at Clarkson, Ontario.

In return, Texaco Canada processes crude oil for Petro-Canada at the Nanticoke refinery and provides a product terminal operation for Gulf Canada at Calgary.

In addition to these long-term supply agreements, products are supplied by Texaco Canada to Ultramar at Halifax, and by Ultramar to Texaco Canada at Montreal, under a reciprocal purchase and sale agreement. This agreement, originally made with Gulf, resulted from the purchase by Ultramar of the remaining Gulf assets in eastern Canada.

The economic benefits of such agreements enable the industry to provide petroleum products to the Canadian public at price levels lower than would be possible if exchanges did not take place.

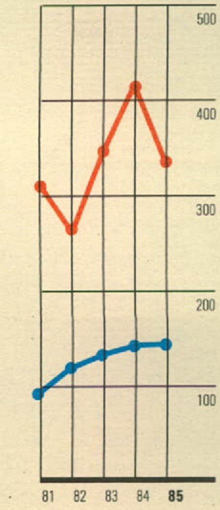
Financial Section

Index to Financial Section

Net Income and Common Dividends
Millions of dollars

Net income

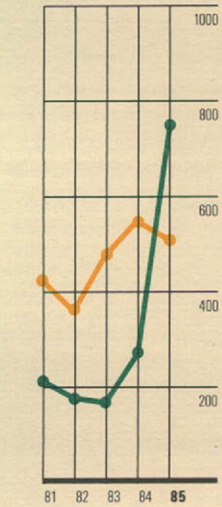
Common dividends



Cash Flow and Re-investment
Millions of dollars

Cash from operations

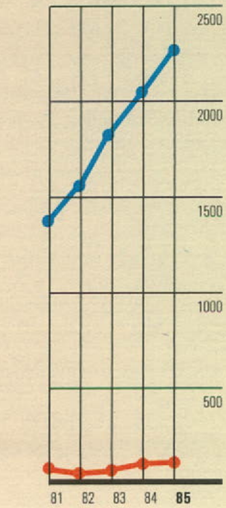
Capital and exploration expenditures



Long-Term Debt and Shareholders' Equity
Millions of dollars

Common shareholders' equity

Long-term debt



Financial Review of 1985

Consolidated Results

Consolidated net income for the year ended December 31, 1985 was $336 million compared to $423 million in 1984 and $344 million in 1983. Net income per common share was $2.74 in 1985 compared with $3.41 in 1984 and $2.74 in 1983.

Consolidated net income for the year ended December 31, 1985 included an unusual inventory adjustment charge of $34 million as described in Note 14 to the Financial Statements. Although earnings are deferred as a result of this inventory adjustment, the earnings effect included in cash from operations on the Statement of Changes is offset by a compensating change in working capital components with no effect on total cash flow from operating activities. Total cash flow from operating activities to the Corporation was $660 million in 1985 compared to $303 million in 1984 and $438 million in 1983.

Revenue from sales and services remained strong, amounting to $4.2 billion in 1985, $4.2 billion in 1984, and $4.1 billion in 1983. In 1985 the Corporation changed its method for reporting reciprocal sales as described in Note 2 to the Financial Statements. Prior years revenues and costs have been reclassified for comparative purposes.

The rate of return on average capital employed decreased to 12.0 per cent in 1985 from previous year returns of 16.2 per cent in 1984 and 14.3 per cent in 1983. Lower net income in 1985 combined with a slightly larger average capital employed accounted for the decline. The Corporation continues to maintain the highest return of any of the major integrated oil companies operating in Canada.

A discussion of the impact of changing prices on the Corporation's results of operations and financial position is described on pages 37 and 38.

Business Segment Information

Energy Resources

The Energy Resources Segment operating income was $272 million in 1985 compared to $373 million in 1984 and $347 million in 1983. The decrease of $101 million from 1984 levels was largely attributable to lower crude oil production and higher expenses, which were partially offset by higher crude oil prices during the year, inclusive of the favourable price impact of deregulation commencing in June of 1985, and increased natural gas sales. The 1985 results include the operations of Canadian Reserve Oil and Gas Ltd. (Canadian Reserve) with effect from the January 2, 1985 acquisition date.

Gross production of crude oil (excluding Canadian Reserve) declined approximately 11 per cent in 1985 due to the natural decline in mature fields, a lack of demand and insufficient pipeline capacity. The decline in Texaco Canada production volumes was partially offset by the additional production volumes resulting from the acquisition of Canadian Reserve.

Upstream expenses (excluding Canadian Reserve) increased $53 million pre-tax in 1985, largely as a result of the company's increased activity levels, and included higher fuel, contract work and dry hole expenses offset somewhat by lower Petroleum and Gas Revenue Tax (PGRT) payments. Total expenses should moderate in 1986 with the commencement of the PGRT phaseout and lower fuel costs which were unusually high in 1985 due to the start-up of enhanced oil recovery programs. The latter expenses increased $26 million before-tax in 1985 versus 1984. The increase in Energy Resources income from $347 million in 1983 to $373 million in 1984 was mainly attributable to higher liquids production and higher prices for crude oil and natural gas, moderated to some degree by increased expenses and PGRT payments.

Petroleum Products

Petroleum Products operating income before write-offs in 1985 was $39 million, compared to $18 million in 1984, and a loss of $46 million in 1983. Write-offs of manufacturing, terminal and marine assets, inclusive of related income tax effects, were less than $1 million in 1985, $21 million in 1984 and $15 million in 1983.

The positive swing in 1985 operating income before write-offs of $21 million was generated by improved profit margins and decreased expenses, tempered by lower sales volumes. The improvement in product margins was largely due to firmer prices in the Ontario market throughout 1985. Lower expenses reflected the company's commitment to closely examining all aspects of the downstream business to ensure operations are carried out in the most efficient and cost effective manner.

Petroleum Products operating income before write-offs of $18 million in 1984 represented a $64 million improvement when compared to the 1983 loss of $46 million. A general improvement in Petroleum Product margins was the main factor in the return to profitability for the segment in 1984.

Capital and Exploration Expenditures

Total capital and exploration expenditures (including the acquisition of Canadian Reserve) were $762 million in 1985. Increased expenditure levels reflect Texaco Canada's commitment to maintain its production capability and find profitable new reserves and to remain a major competitor in the refining and marketing of petroleum products.

Total capital and exploration expenditures excluding Canadian Reserve were $267 million in 1985 compared to $245 million in 1984 and $187 million in 1983. Expenditures in the Energy Resources segment for exploration and production activities increased to $190 million from prior years levels of $161 million in 1984 and $128 million in 1983. Drilling activity increased to record levels for the Corporation, with participation in a total of 322 exploratory and development wells drilled during 1985. This represents a considerable increase over the comparable drilling levels of 246 and 92 wells drilled in 1984 and 1983 respectively. Expenditures in the Petroleum Products segment relating to manufacturing and marketing activities were $74 million in 1985, $73 million in 1984 and $54 million in 1983. Manufacturing expenditures of $34 million in

1985 relate primarily to improvements at the Nanticoke refinery designed to increase refinery capability to produce lead-free gasolines and increase operating efficiencies. Marketing expenditures of $40 million in 1985 are largely related to the company's expansion of the System 2000 network of service stations across the country.

Capital and Exploration Expenditures Years ended December 31	1985	1984	1983
	Millions of Canadian dollars		
Exploration and production	**$190**	$161	$128
Acquisition of Canadian Reserve Oil and Gas Ltd.	**495**	–	–
Manufacturing	**34**	23	18
Marketing	**40**	50	36
Other	**3**	11	5
Total capital and exploration expenditures	**762**	245	187
Deduct: Exploration expenditures and development dry holes charged against current income	**65**	44	52
Total expenditures capitalized	**$697**	$201	$135

Cash From Operations

Cash from operations after exploration expenses and development dry holes was $516 million in 1985 versus $549 million in 1984 and $449 million in 1983. The decrease in 1985 results was largely due to the decline in operating income which included the effect of the unusual inventory adjustment. Lower net income was offset to some degree by non-cash increases in depreciation, depletion and amortization, and deferred taxes, both of which largely relate to the Canadian Reserve acquisition. Canadian Reserve as a corporate entity contributed $75 million to cash from operations in 1985. The increase in cash from operations in 1984 versus 1983 was mainly the result of increased net income.

Liquidity and Capital Resources

Texaco Canada Inc. is one of Canada's most financially sound corporations as evidenced by the 1985 year end cash and working capital balances and debt levels, and by the company's substantial flow of cash from operations.

The company's current ratio of 2.2 exceeds the norm that is common among healthy industrial corporations and short term liquidity is further enhanced by the nature of inventories and accounts receivable which can be readily converted to cash during the normal course of business.

On December 10, 1985 the Corporation purchased from Texaco International Financial Corporation $241 million of Instalment Receipts which represent Texaco Canada Inc. Common Shares that were offered for sale by Texaco International Financial Corporation through a secondary offering prospectus dated February 19, 1985. The amount outstanding and interest earned at a market interest rate were received subsequent to December 31, 1985. In addition, subsequent to December 31, 1985, the Corporation financed for affiliates certain crude oil cargoes valued at $120 million. The amount outstanding carried a market interest rate and was fully repaid by February 19, 1986.

The company's debt/equity ratio of 0.04 and interest coverage of 88 times are both substantially better than general long term liquidity guidelines common in the industry.

Independent agencies have accorded Texaco Canada's long term debt and commercial paper their highest ratings, triple A and R-1 (high) respectively.

In 1985, cash from operations and cash on hand were more than sufficient to meet requirements for capital and exploration expenditures, dividends, preferred share redemptions and the acquisition of Canadian Reserve as outlined in Note 3 to the Financial Statements. It is anticipated that internal resources will be sufficient to fund all capital and exploration expenditure programs planned for 1986. In addition, the Corporation has substantial cash reserves and borrowing capacity to fund other opportunities which may arise.

Stock Market and Dividend Information

Texaco Canada's Board of Directors has declared dividends on the Common Shares in every year since 1944. The total amount paid per Common Share was $1.20 in 1985, $1.20 in 1984, and $1.05 in 1983.

The Corporation's Common Shares are listed on the Toronto, Montreal, Alberta, Vancouver and American stock exchanges. The Toronto Stock Exchange is the principal market for trading these shares. The quarterly high and low prices as quoted on the Toronto Stock Exchange and the dividends paid on the Common Shares were:

1985 Quarter	Price Range High	Low	Dividends Paid	1984 Quarter	Price Range High	Low	Dividends Paid
First	**36 3/4**	**31 3/8**	**$0.30**	First	41 1/2	37 1/2	$0.30
Second	**36 7/8**	**30 1/8**	**$0.30**	Second	39 3/4	36	$0.30
Third	**33 3/8**	**30 3/8**	**$0.30**	Third	41	33 7/8	$0.30
Fourth	**32**	**28 1/2**	**$0.30**	Fourth	41 1/4	35	$0.30

The quarterly high and low prices; as quoted on the American Stock Exchange and the dividends paid on the Common Shares, expressed in U.S. dollars at the then current exchange rate were:

1985 Quarter	Price Range High	Low	Dividends Paid	1984 Quarter	Price Range High	Low	Dividends Paid
First	**27 3/4**	**22 1/2**	**$0.22**	First	33	29 7/8	$0.24
Second	**27 1/4**	**22 3/8**	**$0.22**	Second	31 1/8	27 1/2	$0.23
Third	**24 5/8**	**22**	**$0.22**	Third	31 1/2	25 1/2	$0.23
Fourth	**23 1/2**	**20 5/8**	**$0.22**	Fourth	31 1/8	27	$0.23

On December 31, 1985, there were 6,222 individual, financial and other institutional holders of the Corporation's Common Shares. This compares with a December 31, 1984 total of 4,045 and a total of 4,338 as at December 31, 1983.

The large increase in the number of holders of Common Shares resulted from a public offering in 1985 of 14 million Texaco Canada Common Shares by a subsidiary of Texaco Inc. This was the largest equity issue in Canadian history.

Five-Year Review

Financial Summary	1985	1984	1983	1982	1981
	Millions of Canadian dollars except where noted				
Financial Data					
Revenues					
*Sales and services	$4,212	$4,247	$4,139	$3,679	$3,336
Investment and other income	92	111	74	74	86
	4,304	4,358	4,213	3,753	3,422
Net income	336	423	344	275	316
Per common share (dollars)	2.74	3.41	2.74	2.15	2.45
*Per dollar of revenues (cents)	7.8	9.7	8.2	7.3	9.2
Dividends paid or accrued					
Common shares	145	145	127	121	99
Per common share (dollars)	1.20	1.20	1.05	1.00	0.82
Second preferred shares: Series A	6	11	13	13	13
Series B	–	–	–	2	7
Cash from operations	516	549	449	384	404
Capital and exploration expenditures (inclusive of the $495 acquisition cost of Canadian Reserve)	762	245	187	197	209
Taxes and Crown royalties					
Income taxes	445	526	446	389	370
Federal sales tax	166	137	138	139	135
Petroleum and gas revenue tax	171	182	169	135	72
Petroleum compensation charge	188	261	256	391	513
Crown royalties	392	380	361	335	289
Other taxes and levies	66	58	51	55	50
	1,428	1,544	1,421	1,444	1,429
Motor fuel and excise taxes collected for governments	464	437	464	439	372
	$1,892	$1,981	$1,885	$1,883	$1,801
Financial Position (at year-end)					
Capital employed					
Current assets	$1,488	$1,828	$1,784	$1,466	$1,397
Current liabilities	678	663	743	631	640
Working capital	810	1,165	1,041	835	757
Net properties, plant, and equipment	1,924	1,372	1,300	1,290	1,280
Investments, long-term receivables and other assets	219	209	204	210	202
	2,953	2,746	2,545	2,335	2,239
Total assets	3,631	3,409	3,288	2,966	2,879
Long-term debt	94	94	87	83	86
Deferred gas production revenue and other income	87	72	63	54	16
Deferred income taxes	488	401	403	410	408
Redeemable preferred stock	10	90	170	170	250
Common stock and retained earnings	2,274	2,089	1,822	1,617	1,478
Equity per common share (dollars)	18.83	17.30	15.09	13.40	12.25
Rate of return on average shareholders' equity	15.2 %	21.0 %	19.2 %	16.7 %	21.4 %
Rate of return on average capital employed	12.0 %	16.2 %	14.3 %	12.2 %	14.9 %
Current ratio	2.2	2.8	2.4	2.3	2.2
Share Ownership (at year-end)					
Common shares outstanding (thousands)	120,768	120,768	120,768	120,684	120,681
Common shareholders	6,222	4,045	4,338	5,049	5,366
First preferred shares outstanding	–	–	–	10,759	11,197
First preferred shareholders	–	–	–	87	132

*Sales and services and petroleum product sales have been reclassified as described in Note 2 to the Consolidated Financial Statements.

Operations Statistical Summary

	1985		1984		1983		1982		1981	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Production										
Crude oil (thousands of cubic metres daily)	21.1	14.2	21.8	14.2	20.8	13.7	20.5	12.9	21.2	12.9
** Natural gas liquids (thousands of cubic metres daily)	2.3	2.3	2.3	2.3	2.6	2.6	2.5	2.5	2.3	2.3
** Natural gas (millions of cubic metres daily)	4.0	2.3	3.6	2.0	3.8	2.3	4.3	2.6	4.0	2.3
Estimated Proved Reserves (at year-end)										
Crude oil (millions of cubic metres)	45.9	33.6	45.6	30.5	50.8	33.8	53.1	35.4	58.5	36.5
Natural gas liquids (millions of cubic metres)	20.3	15.7	18.4	13.0	14.1	10.0	14.0	9.9	13.3	9.3
*** Natural gas (billions of cubic metres)	62.8	45.8	51.4	36.0	62.8	44.4	63.3	44.7	65.2	44.3
Oil and Gas Landholdings (at year-end) (thousands of hectares)										
Producing	776	318	507	231	489	223	482	232	488	237
Undeveloped	19527	9447	22956	11413	7175	3576	6481	3416	6751	3695
Total	20303	9765	23463	11644	7664	3799	6963	3648	7239	3932
Wells Drilled										
Exploratory wells										
Oil	54	31.1	21	9.5	14	6.1	6	4.4	6	4.6
Gas	12	5.6	12	4.3	9	5.9	6	5.1	8	3.7
Dry	69	34.7	37	17.5	35	18.9	17	9.4	19	9.2
Development wells										
Oil	159	28.7	166	38.3	28	18.0	17	12.5	29	12.3
Gas	15	8.2	3	1.8	3	1.0	8	4.5	46	11.7
Dry	13	4.5	7	1.2	3	2.3	4	2.2	6	1.7
Total	322	112.8	246	72.6	92	52.2	58	38.1	114	43.2
Wells in the Process of Drilling (at year-end)	14	4.2	12	4.7	9	4.1	10	3.9	4	3.2
Wells Capable of Producing (at year-end)										
Oil	7943	1919	5016	1132	4883	1077	4806	1029	4819	1022
Gas	2194	458	1172	298	1177	293	1245	306	1173	288
Multiple completions included in the above	153	20.3	150	18.8	136	15.6	137	16.5	136	15.6

Refining and Sales	1985	1984	1983	1982	1981
• Refinery input (thousands of cubic metres daily)	21.9	20.9	21.3	23.5	28.2
† Refinery crude oil capacity at year-end (thousands of cubic metres daily)	18.3	18.3	22.7	22.7	34.6
* Petroleum product sales (thousands of cubic metres daily)	25.4	25.3	25.8	26.8	29.7
Natural gas sales (millions of cubic metres daily)	4.1	3.2	3.2	3.7	3.3
Employees					
Number at year-end	3,711	3,635	3,904	4,418	4,522
Payroll and benefits (millions of Canadian dollars)	$ 162	$ 171	$ 174	$ 165	$ 147

** Does not include natural gas and natural gas liquids produced and reinjected into underground reservoirs for enhanced recovery or gas cycling.

*** Effective December 31, 1984 natural gas reserves are stated on a "dry" gas basis. Prior to December 31, 1984 such reserves were reported on a "raw" gas basis.

• Prospectively from 1984 refinery input is defined as crude oil processed at Texaco owned refineries for its own account plus crude oil processed by other refiners on its behalf. Prior to 1984, refinery runs included total crude oil processed at Texaco owned refineries. The effect of this change is an increase of 3.6 thousand cubic metres daily in 1985 and 2.3 thousand cubic metres daily in 1984.

† Refinery crude oil capacity at December 31, 1981 through 1983 included the refinery crude oil capacity at Edmonton, Alberta and at December 31, 1981 included the refinery crude oil capacity at Montreal, Quebec.

Description of Significant Accounting Policies

The financial statements are prepared on the historical cost basis in accordance with accounting principles generally accepted in Canada and conform in all material respects with International Accounting Standards. The more significant accounting policies are set out below.

Principles of Consolidation

The consolidated financial statements include the accounts of Texaco Canada Inc. and its subsidiary companies. The premium paid on subsidiary companies' capital stock at date of acquisition is amortized on a straight-line basis over 20 years. Intercompany accounts and transactions are eliminated. A significant portion of the Corporation's oil and gas exploration and producing activities are conducted jointly with others and accordingly the statements reflect only the Corporation's proportionate interest in such activities.

Foreign Currencies

Foreign currencies are translated into Canadian dollars as follows: (1) current assets except for 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, depletion, and amortization, 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, except for long-term receivables, are reflected in income currently. Commencing in 1984, unrealized foreign currency gains and losses arising on the translation of long-term receivables are deferred and amortized over the remaining terms of the receivables in accordance with an accounting recommendation issued by the Canadian Institute of Chartered Accountants. Previously such gains and losses had been taken into income. This change did not significantly impact net income in 1984.

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 per cent, and for all significant corporate joint ventures owned less than 50 per cent. Under this method, the Corporation's equity in the net income 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 accounted for at cost and the Corporation's interest in the net income of these companies is reflected in income when realized as dividends.

Long-term receivables arising under non-mineral leases are recorded as direct financing leases and are 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 and gas exploration and producing operations. Under this method all exploration 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 proved 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.

When fixed assets representing complete units of property are disposed of, any profit or loss is credited or charged to income. When miscellaneous business properties are disposed of, the difference between the asset cost and the net proceeds on disposal is charged or credited to accumulated depreciation. Prior to January 1, 1984 gains and losses arising on the disposal of miscellaneous business property had been recognized through income. This revision in the method of accounting did not significantly impact income in 1984.

Deferred Gas Production Revenue

Payments received pursuant to take-or-pay provisions included in certain natural gas sales contracts are recorded as deferred gas production revenue. The revenue is recognized when the natural gas to which the payments relate is delivered. Delivery of such natural gas is expected to take place over a ten-year period which commenced November 1, 1984.

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, the related development costs are deferred and amortized to match related revenues.

Deferred Income Taxes

The provision for deferred income taxes reflects the income tax effect on transactions recorded in the 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 taxable income to defer these income tax effects to appropriate future periods in the 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. The cost of pension benefits and valuation adjustments are amortized on an actuarial basis over the remaining estimated service lives of the employees involved.

Royalties

Crude oil and gas royalties payable in kind reduce volumes available to the Corporation and therefore are not reflected in the financial statements. Royalties payable in cash are accounted for as purchases.

Consolidated Statements of Income and Retained Earnings

Years ended December 31	1985	1984	1983
	Millions of Canadian dollars except per share data		
Revenues			
Sales and services (Note 2)	$4,212	$4,247	$4,139
Investment and other income	92	111	74
	4,304	4,358	4,213
Deductions			
Costs and operating expenses (Note 2)	2,611	2,681	2,698
Selling, general and administrative expenses	174	175	180
Maintenance and repairs	47	58	53
Exploration expenses and development dry holes	65	44	52
Depreciation, depletion, and amortization	127	85	83
Interest charges	12	9	9
Petroleum and gas revenue tax	171	182	169
Taxes, other than income taxes (Note 13)	215	175	179
Unusual inventory adjustment (Note 14)	101	–	–
	3,523	3,409	3,423
Income before Income Taxes	781	949	790
Income Taxes (Note 15)			
–current	432	525	438
–deferred	13	1	8
	445	526	446
Net Income	$ 336	$ 423	$ 344
*Net income per common share	$ 2.74	$ 3.41	$ 2.74
Retained Earnings			
Beginning of year	$2,052	$1,785	$1,581
Add–Net income	336	423	344
Deduct–Dividends on preferred shares	6	11	13
–Dividends on common shares	145	145	127
End of year	$2,237	$2,052	$1,785

*Net Income per common share is based on the average number of common shares outstanding (120,768,176 shares in 1985 and 1984, and 120,699,735 shares in 1983).

See accompanying Description of Significant Accounting Policies and Notes to Consolidated Financial Statements.

Consolidated Balance Sheet

December 31	1985	1984
	Millions of Canadian dollars	
Assets		
Current Assets		
Cash	$ 6	$ 83
Cash investments and marketable securities, at cost, which approximates market value	188	340
Accounts and notes receivable		
Trade	561	585
Affiliates (Note 4)	14	278
Other (Note 4)	264	15
Inventories (Note 5)	356	501
Prepaid expenses and deferred income taxes	99	26
Total current assets	1,488	1,828
Investments and Advances (Note 6)	194	180
Properties, Plant, and Equipment (Notes 7 and 11)	1,924	1,372
Deferred Charges	25	29
Total	$3,631	$3,409
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable	$ 372	$ 393
Accrued liabilities	91	106
Income and other taxes payable	215	164
Total current liabilities	678	663
Long-term Debt (Note 8)	94	94
Deferred Gas Production Revenue and Other Income	87	72
Deferred Income Taxes	488	401
Redeemable Preferred Stock (Note 9)	10	90
Common Stock and Retained Earnings		
Common stock—Issued and outstanding: 120,768,176 shares (Note 10)	37	37
Retained earnings	2,237	2,052
Total common stock and retained earnings	2,274	2,089
Total	$3,631	$3,409

See accompanying Description of Significant Accounting Policies and Notes to Consolidated Financial Statements.

Approved on behalf of the Board

James L. Dunlap

James L. Dunlap, Director

SClarke

Stanley D. Clarke, Director

Consolidated Statement of Cash Flow

Years Ended December 31	1985	1984	1983
	Millions of Canadian dollars		
Operating Activities			
Net income	$336	$423	$344
Depreciation, depletion, and amortization	127	85	83
Write-off of non-operating assets, before deferred income taxes	1	38	31
Income taxes—deferred	61	(2)	(7)
Other	(9)	5	(2)
Cash from operations	516	549	449
(Increase)/Decrease in Working Capital, excluding cash[1]			
Accounts and notes receivable	69	(228)	(101)
Inventories	158	63	(44)
Accounts payable	(41)	(24)	136
Accrued liabilities	(15)	14	(4)
Income and other taxes payable	50	(70)	(20)
Prepaid expenses and deferred income taxes	(73)	(2)	13
Deferred gas production revenue	(4)	1	9
Total cash flow from operating activities	660	303	438
Investing Activities			
Acquisition of Canadian Reserve Oil and Gas Ltd., net of cash acquired (Note 3)	486	–	–
Properties, plant, and equipment expenditures	202	201	135
Disposal of properties, plant, and equipment and investment tax credits	(18)	(6)	(11)
Investments and advances (net)	(8)	(3)	(12)
Other	(4)	5	4
Total	658	197	116
Financing Activities			
Long-term debt (net)	–	7	4
Preferred stock redeemed	(80)	(80)	–
Total	(80)	(73)	4
Dividends	151	156	140
Cash[1]			
Increase (decrease) for year	(229)	(123)	186
Beginning of year	423	546	360
End of year	$194	$423	$546

[1]Cash is defined as cash and cash investments and marketable securities.

See accompanying description of Significant Accounting Policies and Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Millions of Canadian dollars except per share data

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. These financial statements would not be materially different if they had been prepared using generally accepted accounting principles as promulgated in the United States.

2. Change in Reporting

The Corporation enters into reciprocal purchase/sale agreements to facilitate shipments of crude oil through a Texaco owned pipeline and minimize petroleum products transportation costs. In 1985, these reciprocal sales transactions, amounting to $1,628, have been netted against Petroleum Products cost of sales. Prior years' sales revenues amounting to $1,909 in 1984 and $1,513 in 1983 have been reclassified to reflect this presentation.

3. Acquisition of Canadian Reserve Oil and Gas Ltd.

On January 2, 1985 the Corporation acquired from a subsidiary of Texaco Inc. for a cash consideration of $495 all of the outstanding shares and an intercompany promissory note of Canadian Reserve Oil and Gas Ltd., ("Canadian Reserve"), an exploration and producing company active primarily in western Canada.

This acquisition has been accounted for as a purchase and net income has been included in the Corporation's results from the date of acquisition.

Details of Canadian Reserve acquisition, at approximate fair market value are:	
Working Capital	$ 32
Properties, plant, and equipment	497
Deferred credits	(34)
Cost to Texaco Canada Inc. of shares and note acquired	$495

In conjunction with Foreign Investment Review Act approval obtained in respect of the acquisition of Canadian Reserve, the Corporation has undertaken to maintain certain levels of capital and exploration expenditures in each of the years 1985 through 1988 inclusive. This period may be extended beyond 1988 under certain conditions. The Corporation's expenditures in 1985 were $762 (inclusive of the acquisition cost of Canadian Reserve).

On a pro forma basis, assuming the two companies had been combined for the year ended December 31, 1984, net income would have been $398 or $3.20 per common share on consolidated revenues of $4,446 (Note 2).

4. Related Party Transactions

Accounts and notes receivable–Other includes an amount of $241 as at December 31, 1985 which represents the purchase from Texaco International Financial Corporation of the final payment due from registered holders of Instalment Receipts. Instalment Receipts represent Texaco Canada Inc. common shares which were offered for sale by Texaco International Financial Corporation through a Secondary Offering prospectus dated February 19, 1985. The amount outstanding and interest earned at a market interest rate were received subsequent to the year-end.

Accounts and notes receivable–Affiliates at December 31, 1984 included a note receivable of $264 from an affiliated company. This amount was advanced at a market interest rate on December 28, 1984 and was repaid on January 2, 1985.

Subsequent to December 31, 1985 the Corporation financed for affiliates certain crude oil cargoes valued at $120. The amount outstanding carried a market rate of interest and was fully repaid by February 19, 1986.

Other transactions between the Corporation and Texaco Inc. and its affiliates arose in the normal course of business. Such transactions were at competitive market terms and are not significant in relation to the Corporation's activities.

Additionally, amounts due from an affiliated company under direct financing leases are shown in Note 6.

5. Inventories

December 31	1985	1984
Crude oil	$103	$150
Petroleum products and other merchandise	234	341
Materials and supplies	19	10
Total	$356	$501

Notes to Consolidated Financial Statements

Millions of Canadian dollars except per share data

6. Investments and Advances

December 31	1985	1984
Non-subsidiary companies accounted for:		
On equity method	$ 49	$ 32
At cost	1	1
	50	33
Other investments		
Direct financing leases—affiliated company	137	142
Notes, mortgages and other long-term receivables	7	5
Total	$194	$180

Texaco Canada's equity in the net income of the non-subsidiary companies accounted for on the equity method aggregated $2 in 1985, $3 in 1984, and $6 in 1983. Dividends received from companies accounted for by this method amounted to $5 in 1985, $8 in 1984, and $6 in 1983. Undistributed income of these non-subsidiary companies included in Texaco Canada's retained earnings amounted to $8 as at December 31, 1985 and $11 as at December 31, 1984.

7. Properties, Plant, and Equipment

	Cost		Accumulated depreciation, depletion, and amortization	
December 31	1985	1984	1985	1984
Exploration and production	$1,541	$ 947	$395	$326
Manufacturing	614	580	136	118
Marketing	415	411	148	159
Marine	17	17	7	6
Pipelines	13	12	7	6
Other	30	32	13	12
Total	$2,630	$1,999	$706	$627
Net properties, plant, and equipment	$1,924	$1,372		

8. Long-term Debt

December 31	1985	1984
10¾% debentures, 1974 series, due 1994 ($5 annual sinking fund requirement 1986-1993)	$70	$ 75
5% debentures, from joint venture partner, due not later than 1997	24	19
Capital lease obligations (Note 11)	5	6
	99	100
Less:		
10¾% debentures held for sinking fund requirements	1	5
Amounts due within one year included in current liabilities	4	1
Total	$94	$ 94

9. Redeemable Preferred Stock

December 31	1985	1984
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: 1985, 100,000 shares and 1984, 900,000 shares	$10	$ 90

Second Preferred Shares, Series A, are redeemable at $100.00 per share on the last day of February, May, August and November in each twelve-month period after June 1, 1984. 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. During each of the years 1985 and 1984, 800,000 shares were redeemed.

In the event of a distribution of the assets of the Corporation among its shareholders for the purpose of winding up its affairs, the holders of the Second Preferred Shares shall be entitled to receive an amount equal to $100.00 per share plus all accrued and unpaid dividends thereon, the whole to be paid before any amount is paid or any assets of the Corporation are distributed to the holders of the Common Shares, or the shares of any other class ranking junior to the Second Preferred Shares.

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

10. Capital Stock

December 31	1985	1984
Common Stock		
Authorized:		
Unlimited number of common shares without nominal or par value		
Issued and outstanding:		
120,768,176 common shares	$37	$37

The Corporation is authorized to issue, in series, an unlimited number of First Preferred Shares without nominal or par value. On November 15, 1983 the Corporation redeemed at its option all of the outstanding First Preferred Shares, Series A, for a cash consideration of $102.50 per share. Prior to the redemption date, these shares were convertible into fully paid and non-assessable Common Shares on the basis of eight Common Shares for each First Preferred Share. During 1983, 10,475 First Preferred Shares, Series A, were converted into 83,800 Common Shares.

During each of the three years ended December 31, 1985, 1984 and 1983, the following changes were reflected in the number of Common Shares and First Preferred Shares, Series A:

	1985	1984	1983
Common Shares			
Outstanding at beginning of year	**120,768,176**	120,768,176	120,684,376
Add:			
Conversion of First Preferred Shares into Common Shares	–	–	83,800
Outstanding at end of year	**120,768,176**	120,768,176	120,768,176
First Preferred Shares, Series A			
Outstanding at beginning of year	–	–	10,759
Deduct:			
Conversion of First Preferred Shares into Common Shares	–	–	10,475
Redemption of First Preferred Shares	–	–	284
Outstanding at end of year	–	–	–

Dividends paid per Common Share were $1.20 in 1985 and 1984, and $1.05 in 1983.

11. Capital Leases, Lease Commitments and Rental Expense

As at December 31, 1985 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 reflected in the balance sheet as assets along with the related debt. The remaining lease obligations are considered to be operating leases and are reflected in the income statement as rental expense as incurred.

Leased capital assets included in Properties, Plant, and Equipment are:

December 31	1985	1984
Land	$ –	$ 9
Buildings and equipment	9	20
	9	29
Less: Accumulated amortization	6	18
Net capital leases	$ 3	$11

Future minimum lease payments on non-cancellable operating leases and capital leases as at December 31, 1985 are:

	Operating Leases	Capital Leases
1986	$13	$1
1987	11	1
1988	8	1
1989	7	1
1990	6	1
After 1990	8	2
Total minimum lease payments	$53	$7
Less: Amount representing interest		2
Present value of capital lease obligations (Note 8)		$5

Notes to Consolidated Financial Statements

Millions of Canadian dollars except per share data

11. Capital Leases, Lease Commitments and Rental Expense (continued)

Future minimum rental income from non-cancellable sub-leases amount to $12 in respect of operating leases and $6 in respect of capital leases.

Rental expense comprises:

Years ended December 31	1985	1984	1983
Minimum rentals	$46	$44	$39
Contingent rentals	7	6	5
	53	50	44
Less: Rental income from sub-leased properties	32	31	30
Net rental expense	$21	$19	$14

Rental expense includes minimum rental payments applicable to operating leases for service stations, office buildings and other facilities, charter hire payments in respect of tankers as well as rental payments which are contingent on such factors as litres sold. Rental payments on leases to retain mineral rights are excluded.

12. Contingent Liabilities

In the opinion of the Corporation's General Counsel, while it is impossible to ascertain the ultimate legal and financial liability with respect to contingent liabilities, including lawsuits, income taxes, claims, guarantees, etc., the aggregate amount of such liability should not be materially significant in relationship to the financial position of the Corporation and its subsidiaries.

13. Taxes, Other Than Income Taxes

Years ended December 31	1985	1984	1983
Federal sales tax	$166	$137	$138
Mineral tax	23	10	14
Property tax	18	17	17
Other	8	11	10
Total	$215	$175	$179

In addition, federal excise tax and provincial motor fuel and oil taxes paid or due to taxing authorities for the years ended December 31, 1985, 1984 and 1983 in the amounts of $464, $437, and $464, respectively, have not been included in the income statement.

14. Unusual Inventory Adjustment

Effective June 1, 1985, coincident with decontrol of crude oil prices, the Corporation was no longer required to market certain crude oil through the Alberta Petroleum Marketing Commission. As a result, because related inventories are stated at the Corporation's cost of producing the product, unrealized producing profits in inventory are being deferred until the final point of sale. The after tax effect of the adjustment is a $34 reduction in net income.

15. Income Taxes

The provision for deferred income taxes relates to:

Years ended December 31	1985	1984	1983
Intangible drilling costs	$34	$3	$7
Depreciation	19	(9)	(9)
Inventories (Note 14)	(48)	3	16
Other	8	4	(6)
Total	$13	$1	$8

The following schedule reconciles the effective income tax rates with the statutory income tax rates:

	1985		1984		1983	
Years ended December 31	Amount	%	Amount	%	Amount	%
Income taxes at statutory rates	$374	48	$445	47	$377	48
Petroleum and gas revenue tax	83	11	86	9	81	10
Resource allowance	(166)	(21)	(174)	(18)	(170)	(22)
Disallowed royalties	200	26	188	20	183	23
Provincial tax credits and rebates	(18)	(2)	(13)	(2)	(17)	(2)
Other	(28)	(5)	(6)	(1)	(8)	(1)
Income taxes and their effective rates as reflected in the consolidated statement of income	$445	57	$526	55	$446	56

16. Segmented Financial Data

Business Segments Years ended December 31	Energy Resources 1985	1984	1983	Petroleum Products 1985	1984	1983	Consolidated 1985	1984	1983
Sales and services									
Outside (Note 2)	**$ 586**	$1,016	$ 860	**$3,626**	$3,231	$3,279	**$4,212**	$4,247	$4,139
Intersegment	**829**	382	446	**2**	2	1	**–**	–	–
	1,415	1,398	1,306	**3,628**	3,233	3,280	**4,212**	4,247	4,139
Income (loss) after income taxes									
Operating income (loss) before write-offs	**272**	373	347	**39**	18	(46)	**311**	391	301
Write-off of manufacturing, terminal and marine assets	**–**	–	–	**–**	(21)	(15)	**–**	(21)	(15)
Operating income (loss)	**272**	373	347	**39**	(3)	(61)	**311**	370	286
Non-operating income, unallocated corporate expenses and consolidation adjustments							**25**	53	58
Net Income							**336**	423	344
Identifiable Assets									
Segment assets	**1,395**	896	1,079	**1,739**	1,770	1,865	**3,134**	2,666	2,944
Corporate assets and consolidation adjustments							**497**	743	344
Total Assets							**3,631**	3,409	3,288
Depreciation, depletion, and amortization	**86**	44	44	**41**	41	39	**127**	85	83
Capital and Exploration Expenditures	**190**	161	128	**77**	84	59	**267**	245	187
Acquisition of Canadian Reserve Oil and Gas Ltd.	**$ 495**	$ –	$ –	**$ –**	$ –	$ –	**$ 495**	$ –	$ –

The segmented financial data is presented as if each segment was a separate business activity. All intersegment transactions have been eliminated in the consolidated figures. Intersegment revenues are based on prices which are generally representative of market prices.

Energy resources comprises exploration, development and production activities for crude oil, natural gas liquids, natural gas, oil sands and minerals, as well as Company owned pipeline operations.

Petroleum products includes the manufacture, distribution and marketing of refined petroleum products and petrochemical products, as well as the purchase and sale of crude oil and natural gas liquids.

Notes to Consolidated Financial Statements

Millions of Canadian dollars except per share data

17.
Pension Plan

The expense for the service cost component of the employee pension plan amounted to $5 in 1985, $8 in 1984, and $10 in 1983. The most recent actuarial valuation of the plan which was dated January 1, 1985 contained revised actuarial and economic assumptions, and combined with improved investment performance, indicated that the plan had a surplus of $59. The 1985 pension expense was offset by a credit of $10 which represented the amortization of this surplus including interest, resulting in a net pension credit of $5. The present value of the unfunded liability of $10 in respect of prior service at December 31, 1983 was provided in 1984 through the application of a portion of the plan's surplus.

Accrued plan benefits and plan net assets were:

January 1	1985
Actuarial present value of accrued plan benefits (which includes the impact of future salary increases):	
Vested	$151
Nonvested	5
Total	$156
Actuarial fair market value of net assets available for benefits	$215
Weighted average assumed rate of return used in determining the actuarial present value of plan benefits	9.5%

Auditors' Report

ARTHUR ANDERSEN & CO.
CHARTERED ACCOUNTANTS

To the Shareholders of Texaco Canada Inc.:
We have examined the consolidated balance sheet of Texaco Canada Inc. and subsidiary companies as of December 31, 1985 and 1984, and the related consolidated statements of income, retained earnings and cash flow for each of the three years in the period ended December 31, 1985. 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, 1985 and 1984, and the results of their operations and changes in their cash flow for each of the three years in the period ended December 31, 1985, in accordance with generally accepted accounting principles applied on a consistent basis.

Arthur Andersen & Co.

Toronto, Ontario
February 19, 1986.

Oil and Gas Producing Activities

Millions of Canadian dollars except where noted

Capitalized Costs

December 31	1985	1984
Proved properties	**$1,306**	$800
Unproved properties	**187**	110
Support equipment and facilities	**20**	12
Gross capitalized costs	**1,513**	922
Less: Accumulated depreciation, depletion, and amortization	**384**	315
Net capitalized costs	**$1,129**	$607

Capitalized costs represent the costs of proved and unproved properties, including support equipment and facilities, along with the related accumulated depreciation, depletion, and amortization.

Costs Incurred

Years ended December 31	1985	1984	1983
Acquisition of proved properties	**$371**	$ –	$ –
Acquisition of unproved properties	**101**	25	17
Exploration costs	**76**	56	60
Development costs	**132**	81	46
Total costs incurred	**$680**	$162	$123

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.

Oil and Gas Producing Activities

Millions of Canadian dollars except where noted

Results of Operations from Producing Activities

Years ended December 31	1985	1984	1983
Revenues			
Sales to unaffiliated entities	$ 514	$ 948	$ 804
Transfers within Texaco Canada and sales to unconsolidated affiliates	785	341	401
Total	1,299	1,289	1,205
Production costs			
Petroleum and gas revenue tax	171	182	169
Other production costs	237	148	122
Total	408	330	291
Exploration and development expenses	63	41	49
Depreciation, depletion, and amortization	85	42	43
Results of operations from producing activities before estimated income tax	743	876	822
Estimated income tax	460	505	476
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 283	$ 371	$ 346

The results of operations from producing activities should not be construed to be energy resources operating income, as apart from excluding corporate overhead and interest costs, the revenue and cost of purchased oil and gas, including royalties, is not included in the table.

Estimated income tax has been computed by applying the statutory income tax rates to the pre-tax results of operations and reflects permanent differences and tax credits and allowances relating to the oil and gas producing activities.

Average Sales Prices and Production Costs

Years ended December 31	1985	1984	1983
	Canadian dollars per cubic metre		
Average sales prices			
Crude oil	$234.62	$214.56	$205.56
Natural gas liquids	174.92	171.73	157.38
Natural gas	.10	.11	.10
Average production costs	59.63	48.91	43.72

Average sales prices and average production costs per cubic metre are based on revenues and production costs, respectively, as reported in the Results of Operations from Producing Activities.

Production costs include cash lifting costs, excluding payments for royalties and income taxes. However, it is important to note that such royalties and income taxes substantially add to the total cost of producing operations and substantially reduce the profitability and cash flow from such operations.

Reserve Quantity Information

	Crude oil Millions of cubic metres	Natural gas liquids Millions of cubic metres	Natural gas Billions of cubic metres
Net proved developed and undeveloped reserves			
*As at December 31, 1982	35.4	9.9	44.7
Increase (decrease) during 1983 attributable to:			
Revisions of previous estimates	(0.2)	0.8	(0.4)
Improved recovery	3.2	–	0.4
Extensions, discoveries and other additions	0.3	–	0.5
Production	(4.9)	(0.7)	(0.8)
*As at December 31, 1983	33.8	10.0	44.4
Increase (decrease) during 1984 attributable to:			
Revisions of previous estimates	–	0.2	(8.3)
Improved recovery	1.5	–	0.2
Extensions, discoveries and other additions	0.4	3.7	0.4
Production	(5.2)	(0.9)	(0.7)
*As at December 31, 1984	30.5	13.0	36.0
Increase (decrease) during 1985 attributable to:			
Revisions of previous estimates	**2.2**	**1.1**	**0.2**
Purchase of minerals in place	**5.1**	**0.4**	**10.1**
Improved recovery	**0.5**	–	**0.1**
Extensions, discoveries and other additions	**0.5**	**2.0**	**0.2**
Production	**(5.2)**	**(0.8)**	**(0.8)**
*As at December 31, 1985	**33.6**	**15.7**	**45.8**
*Includes net proved developed reserves of Texaco Canada Inc. and subsidiary companies:			
As at December 31, 1982	35.4	9.9	41.6
As at December 31, 1983	33.6	9.9	41.2
As at December 31, 1984	30.2	12.9	33.7
As at December 31, 1985	**33.4**	**15.7**	**43.3**

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 governments or authorities in which the Corporation acts as producer.

The foregoing reserve quantities 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. Net reserves represent the volume estimated to be available after deduction of the royalty interests of others from gross reserves. 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.

Prior to December 31, 1984 estimates of the Corporation's natural gas reserve quantities were reported on a "raw" gas basis and included the volume of the percentage of natural gas liquids which may be removed at locations beyond lease and/or field separation facilities. Effective December 31, 1984 the Corporation's estimates of natural gas reserves are on a "dry" gas basis and account for shrinkage resulting from anticipated natural gas liquids recovery through existing facilities.

As at December 31, 1982, 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. These price increases for old oil have been limited to 75 per cent of the world crude oil prices existing as at December 31, 1982. Net reserves as at December 31, 1985, 1984 and 1983 have been determined using prices and the royalty structure in effect at these dates. The increase attributable to "revisions of previous estimates" in 1985 is largely the result of the provincial royalty changes announced during the year.

Oil and Gas Producing Activities

Millions of Canadian dollars except where noted

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

December 31	1985	1984	1983
Future cash inflows	**$14,732**	$13,002	$12,387
Future development and production costs	**3,023**	3,888	3,758
Future income tax expenses	**6,090**	5,139	4,910
Future net cash flows	**5,619**	3,975	3,719
10% Annual discount for estimated timing of cash flows	**3,004**	2,057	1,802
Standardized measure of discounted future net cash flows	**$2,615**	$1,918	$1,917

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

Years ended December 31	1985	1984	1983
Standardized measure at beginning of year	**$1,918**	$1,917	$2,010
Increases (Decreases):			
Sales and transfers of oil and gas produced, net of production costs	**(878)**	(955)	(914)
Net changes in prices and production costs	**489**	568	(212)
Changes in estimated future development costs	**(17)**	(108)	(5)
Extensions, discoveries, other additions and improved recovery, less related costs	**161**	316	472
Development costs incurred during the year	**75**	76	41
Purchase of minerals in place, net of related income taxes	**245**	–	–
Revisions of previous quantity estimates	**187**	(415)	(376)
Accretion of discount	**442**	467	517
Net change in income taxes	**(7)**	52	384
Standardized measure at end of year	**$2,615**	$1,918	$1,917

The reader is cautioned that extreme care be exercised in the use of the foregoing data on standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves. Texaco Canada is presenting this information in good faith in compliance with the requirements of FASB 69. While the Corporation has exercised 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 foregoing tables in conjunction with the accompanying qualifications and caveats.

The above value-based information is based on future cash flows from production of proved reserves assuming certain economic and operating conditions. No value is assigned to the potential success Texaco Canada might enjoy from current exploration and/or from assets currently held which might benefit from future technological and economic conditions.

There are many variables, assumptions and imprecisions inherent in the development of future cash flow projections and these 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, and future government actions regarding production, taxes, royalties, etc.

The above future cash inflows were computed using year-end prices, which as at December 31, 1985, were deregulated. Prices as at December 31, 1982, 1983 and 1984 were regulated under the National Energy program. Estimates of future production were increased as at December 31, 1985 because of provincial royalty changes announced in 1985. The future costs, with the exception of petroleum and gas revenue tax (P.G.R.T.), and income tax expenses were computed using year-end costs and year-end statutory tax rates respectively, adjusted for permanent differences, that relate to existing proved oil and gas reserves in which the Corporation has mineral interests. Future P.G.R.T. costs are based upon a phasing out formula which was set out in the Western Accord.

The discount rate utilized in the foregoing tables is 10 per cent, as specified by FASB 69. 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 its frontier areas, the availability of financing, and the state of the economy.

The accretion of discount is the amount by which the present value of estimated future net revenues from estimated net production of proved oil and gas reserves at the beginning of the year increased during the year due to the passage of time.

Financial Data Adjusted for Changing Prices

Millions of Canadian dollars

The usefulness of the Corporation's financial statements prepared on the historical cost basis is limited in prolonged periods of significant inflation. These statements do not reflect the impact on the financial position and operating results of changes in the general purchasing power of the dollar or in changes of specific prices of goods and other assets.

The Canadian Institute of Chartered Accountants (CICA) has issued a Recommendation which requires that supplemental data be presented to provide current cost adjusted information to reflect the effect of changing prices.

While Texaco Canada presents the current cost adjusted information in compliance with CICA requirements, and has exercised due care in developing such data, it is necessary to present the data with qualifications and cautions as to their interpretation and usefulness. Management cautions against the simplistic use of these data as a means of precisely measuring the effects of changing prices because of the imprecisions inherent therein.

Consolidated Statement of Income

Years ended December 31	As reported in the Historical Cost Statement 1985	Current Cost Basis 1985	Current Cost Basis 1984*
Revenues (Note 2)	$4,304	$4,304	$4,533
Deductions			
Costs and operating expenses (Note 2)	2,611	2,586	2,807
Depreciation, depletion, and amortization	127	244	193
Other expenses	785	785	669
	3,523	3,615	3,669
Income before Income Taxes	781	689	864
Income Taxes			
—current	432	432	546
—deferred	13	13	1
	445	445	547
Net Income	$ 336	$ 244	$ 317

Consolidated Balance Sheet Items

December 31	1985	1985	1984*
Inventories	$ 356	$ 357	$ 525
Net properties, plant, and equipment	1,924	2,987	2,614
Net assets (common shareholders' equity)	2,274	3,338	3,364

Other Supplementary Information

Years ended December 31		1985	1984*
Increase in the current cost of inventories and properties, plant, and equipment held during the year was attributed to:			
Effect of general inflation		$147	$116
Increase (decrease) in specific prices		(127)	(78)
Total increase in the current cost of inventories and properties, plant, and equipment		$ 20	$ 38
Loss in general purchasing power from having net monetary assets		$ 23	$ 18

*Restated using the Statistics Canada Consumer Price Index to reflect financial data in dollars of equal purchasing power.

Financial Data Adjusted for Changing Prices

Current Cost Estimates

In accordance with CICA requirements, only cost of goods sold included in the caption "Costs and operating expenses" and depreciation, depletion, and amortization expense are adjusted for changing prices. Revenues, other expenses and income taxes are not required to be restated as it is assumed that these historical dollar amounts are stated in average dollars for the year.

In preparing the estimates of current costs, it was necessary to make many assumptions and rely upon judgmental estimates, which were inherently subjective in nature. The bases for calculating estimated current costs were as follows:

Inventories
Current cost values have been developed on the first-in, first-out (FIFO) method of accounting. Capitalized depreciation included in inventories has been adjusted to a current cost basis.

Cost of Goods Sold
Current cost of goods sold has been estimated by valuing inventories on a last-in, first-out (LIFO) basis. The resulting cost of sales is considered to be representative of current cost since the most recent acquisitions (current purchases) are deemed to be sold first.

Properties, Plant, and Equipment
Current cost estimates of properties, plant, and equipment have been largely developed by applying various indices to the historical cost of reasonably homogeneous groupings of assets. Due to the capital-intensive nature of the oil industry, it was considered not practical to attempt to develop current cost estimates for individual assets. While Texaco Canada is not in a position to attest to the accuracy, consistency, weighting or other factors affecting published indices, it is believed that the indices used are reasonable. These current cost estimates are not to be construed as an indication of appraised or replacement values nor as a basis that these assets will necessarily be replaced in future.

Depreciation, Depletion, and Amortization
For purposes of calculating depreciation, depletion, and amortization both on a current cost and historical cost basis, the same useful lives and salvage values have been used.

Income Taxes

The CICA pronouncement does not require that the income taxes deducted in determining historical cost results be recalculated in the determination of current cost income. Income taxes as reported in the historical cost statements represent an effective tax rate of 57 per cent of income before income taxes. Since income taxes have not been adjusted in arriving at current cost net income, the effective income tax rate applicable to pre-tax income on a current cost basis is 65 per cent. This result demonstrates clearly that income taxes are paid on profits which in part arise from the effect of inflation.

Increase in Current Cost

Other Supplementary Information includes data analyzing the increase in the current cost of inventories and properties, plant, and equipment held during the year. This information indicates that the effect of general inflation in 1985 accounted entirely for the increase in current cost. This increase was partially offset by decreased specific prices.

Loss in Purchasing Power

Other Supplementary Information also includes a caption "Loss in general purchasing power from having net monetary assets". Inflation not only affects the reported results of operations, but also affects the purchasing power of monetary assets held, such as cash and receivables, and monetary obligations, such as accounts payable and debt. During inflationary periods, monetary assets lose purchasing power and there is an opposite effect on monetary liabilities since less purchasing power will be needed to repay the obligations. The amount set forth as "Loss in general purchasing power from having net monetary assets" represents an estimate of how much the Corporation's purchasing power was effectively decreased as a result of having a greater amount of monetary assets than monetary liabilities.

Selected Quarterly Financial Data

Quarter ended	Sales and services*	Gross profit**	Net income	Net income per common share
	Millions of Canadian dollars except per share data			
1985				
March 31	**$1,178**	**$215**	**$ 99**	**$0.81**
June 30	**1,132**	**166**	**72**	**0.58**
September 30	**877**	**108**	**66**	**0.53**
December 31	**1,025**	**212**	**99**	**0.82**
1984				
March 31	1,142	240	119	0.96
June 30	990	187	90	0.72
September 30	982	211	104	0.83
December 31	1,133	209	110	0.90
1983				
March 31	939	157	76	0.61
June 30	1,000	160	75	0.59
September 30	1,066	231	107	0.86
December 31	1,134	177	86	0.68

*Sales and services have been reclassified as described in Note 2 to the Consolidated Financial Statements.

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

Glossary

Bitumen
A thick, tar-like hydrocarbon which, in its natural state, is semi-solid and therefore not producible directly through a well.

Canada Lands
The areas of Canada where the federal government has jurisdiction over oil and gas rights, including the Yukon, the Northwest Territories and other areas north of 60 degrees latitude, and areas off the east and west coasts.

Completing a well
The operations required to prepare a well for production, injection or observation after the zone of interest has been assessed by drilling.

Deep Cut
The recovery, to the maximum practical extent, of natural gas components as liquid product. Normally, this requires the use of cryogenic (very low temperature) processing and implies the recovery of ethane and heavier components as a natural gas liquids mix. This mix may then be separated into discrete products.

Development well
A well drilled in an area already proven to be productive.

Downstream
The manufacturing, marketing and transportation of products derived from producing and petrochemical activities.

Dry gas
Natural gas that has been processed through a gas plant for removal of heavier hydrocarbons and/or impurities to meet quality specifications required for use as a domestic or industrial fuel.

Dry hole
A well incapable of producing hydrocarbons in economically feasible quantities.

Enhanced oil recovery
See Secondary recovery and Tertiary recovery.

Exploratory well
A well drilled in an unproven area for the purpose of determining the existence of economically feasible quantities of hydrocarbons. Also called a wildcat.

Farm-in
An arrangement between two or more parties whereby one party agrees to drill a well on another party's lease, and pays all or a share of the cost in return for a specified interest in any oil or gas it finds.

Farm-out
The opposite of a farm-in, whereby an operator owning a lease who does not want to drill agrees to assign the lease, or a portion of it, to another party wishing to drill the property.

Frontier areas
See Canada Lands.

Gas cycling
A procedure to increase ultimate recovery of the natural gas liquid components in which high pressure inlet gas from a reservoir is processed through a gas plant, natural gas liquids are extracted, and the remaining residue gas is returned to the reservoir.

Gross landholdings/wells
The total landholdings/number of wells in which the Corporation owns an interest.

Gross production/reserves
The Corporation's share of production/reserves before deducting royalties due others.

Heavy oil
A thick hydrocarbon that can be pumped only at low rates from a well without the addition of energy into the reservoir. It is thinner than bitumen but far thicker than conventional crude.

Hydrocarbon miscible flood
A secondary or tertiary recovery method in which the reservoir is first injected with solvents, such as ethane and propane, in order to sweep the remaining oil from porous rock. Natural gas, which acts as a chaser material, is then forced into the reservoir to maintain oil production.

In-situ recovery
A method of recovering heavy oil or bitumen which is not recoverable by conventional production methods or mining. Essentially, the oil in the ground is heated to make it flow more easily, while the sand is left in place.

Infill well
Wells drilled within the proved boundaries of a reservoir to increase production.

Middle distillates
A range of refined petroleum products which includes kerosene, stove oil, diesel fuel and light fuel oil.

Miscible flood
See Hydrocarbon miscible flood.

Natural gas liquids
A mixture of those hydrocarbons liquefied in the processing of raw gas or condensate at the surface in field facilities or in gas processing plants. This mixture can include some or all of the following components: ethane, propane, butanes and pentanes plus.

Net landholdings/wells
The Corporation's interest in landholdings/number of wells after deducting the interests of others.

Net production/reserves
The Corporation's share of production/reserves after deducting royalties due others.

Oil sands
Sands saturated with bitumen. In Canada, these deposits, also referred to as tar sands, are located in northern Alberta.

Petroleum and Gas Revenue Tax (PGRT)
A federal tax applied to gross Canadian oil and gas production revenue net of deductions for production operating expenses (other than depreciation, interest, Crown royalties, mineral taxes and certain other items) and a resource allowance. PGRT is not deductible for income tax or provincial royalty calculations, and is being phased out by 1989.

Petroleum Compensation Charge (PCC)
A federal tax levied at the refinery gate on all domestic or foreign crude oil which is processed or consumed in Canada.

Petroleum Incentives Program (PIP)
A federal program providing direct incentive payments to

enterprises in respect of exploration and development activities in Canada. The incentive varies according to the area and nature of the activity, and the degree of Canadian ownership and control of the participating company. To be eliminated effective March 31, 1986 except for commitment wells which are grandfathered to the end of 1987.

Petrophysical
Refers to the study of such physical properties of reservoir rocks as porosity, hydrocarbon content and flow capability. Petrophysical techniques assist in locating pay zones in well bores and in planning optimum oil recovery methods.

Primary recovery
The production of crude oil by natural reservoir energy.

Prorationing
Assigning an allowed level of oil production to individual producers when total Alberta productive capacity exceeds demand or when pipelines are unable to move all the oil to market. The Alberta Energy Resources Conservation Board determines a monthly allowable based on these factors and distributes that allowable production level to producers on the basis of recognized reserves. In addition, pipeline companies allocate production when short term production levels exceed their capacity.

Raw gas/Wet gas
Unprocessed natural gas which may contain liquid hydrocarbons, water and other impurities.

Refinery input
Crude oil processed at Texaco owned refineries for its own account plus crude oil processed by other refiners on its behalf.

Royalties
A percentage of gross production which belongs to the owner of the mineral rights. Where the mineral rights are owned by a provincial or federal government, they are referred to as Crown royalties.

Secondary recovery
A process usually involving repressuring through the injection of gas or water to increase crude oil production and reserves.

Seismic
The measurement of the configuration of rocks beneath the surface of the earth by using a sensitive receiver to record the response to the introduction of a sound or vibration pulse.

Spud
To commence drilling of a well.

Steamflood
A tertiary recovery method whereby steam is pumped into a reservoir to heat the oil and improve its flowing properties so the oil can be produced.

Step out/delineation well
A well drilled in an unproven area, which is adjacent to a proven area, to determine the extent of a productive reservoir.

Tertiary recovery
The use of sophisticated techniques, such as the flooding of formations with gas or water combined with certain chemicals or adding heat energy to the formation, in order to increase recovery of oil over that achieved by primary depletion or secondary recovery.

Upstream
The section of the oil and gas industry devoted to the exploration for, development and production of crude oil, natural gas, natural gas liquids and sulphur, as well as the production of synthetic oil.

Working interest
A participating interest, expressed as a percentage, pursuant to a joint venture agreement. Working interest owners share in all costs and all production.

Conversion factors
Approximate metric conversion factors are:
One cubic metre of liquids = 6.29 barrels
One cubic metre of gas = 35.3 cubic feet
One hectare = 2.47 acres
One kilometre = 0.62 miles
One tonne = 2,205 pounds

Subsidiary Companies
Texaco Canada Resources Ltd.

Oilship Limited

Great Eastern Oil Ltd.

McColl-Frontenac Oil Co. Ltd.

Lowry Fuels Limited

Limited Partnership
Texaco Canada Resources

Principal Investments and Percentage Interest

AT&S Exploration Ltd. 25%

Federated Pipe Lines Ltd. 50%

Trans-Northern Pipelines Inc. 33.33%

Alberta Products Pipe Line Ltd. 20%

Montreal Pipe Line Limited 16%

Transfer Agents and Registrars in Canada:
Montreal Trust Company of Canada, 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.

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Mr. R.M. Routhier is not present.

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