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Texaco Canada Inc.
Annual Report

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

Contents

Corporate Profile
Texaco Canada is a fully-integrated petroleum company involved in exploration activities in western Canada, the Northwest Territories, off the Atlantic Coast, and in four countries outside Canada.

The Company is Canada's largest producer of conventional crude oil and natural gas liquids and is a major competitor in the downstream refining and marketing of petroleum products.

It operates refineries at Nanticoke, Ontario, and at Halifax, Nova Scotia, and has contracts for processing capacity in Quebec and in Alberta. These facilities and an extensive distribution system support the marketing of petroleum products throughout the country.

Texaco Canada ranks fifth in assets among Canada's integrated oil companies but has the highest return on shareholder equity.

The Annual Meeting of Shareholders of Texaco Canada Inc. will be held in the Glenbow-Alberta Institute Theatre, at the Glenbow Centre, 130-9th Avenue S. E., Calgary, Alberta, on Friday, May 3, 1985, at 10:30 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

Subsidiary Companies
Texaco Canada Resources Ltd.

Oilship Limited

Great Eastern Oil Ltd.

McColl-Frontenac Oil Co. Ltd.

Lowry Fuels Limited

Principal Investments and Percentage Interest
Federated Pipe Lines Ltd. 50%

Trans-Northern Pipelines Inc. 33.33%

Alberta Products Pipe Line Ltd. 20%

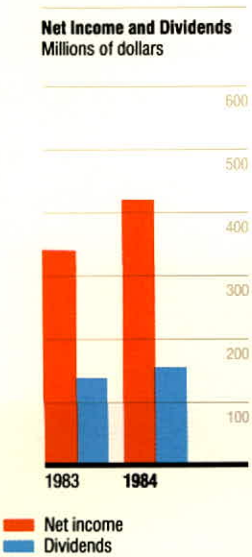
Montreal Pipe Line Limited 16%

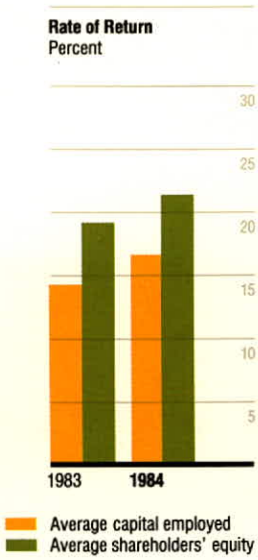
Transfer Agents and Registrars in Canada:
Montreal Trust Company of Canada, Montreal, Toronto, Winnipeg, Regina, Calgary and Vancouver

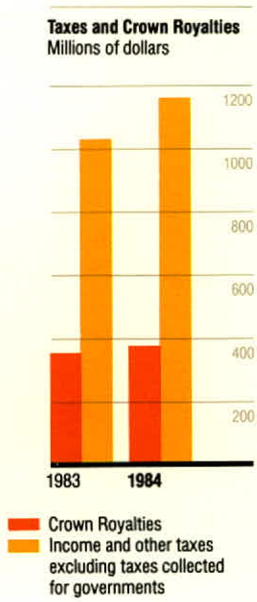
Transfer Agents and Registrars in the United States:
The Royal Bank & Trust Company, 68 William Street, New York, N.Y.

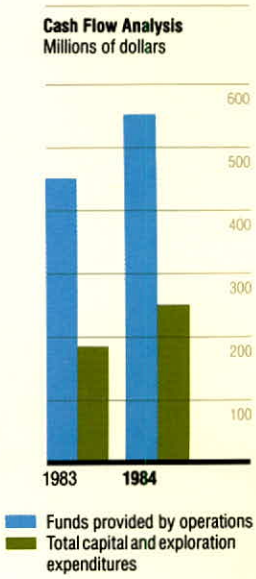
Highlights

Financial	1984	1983
	Millions of Canadian dollars	
Revenues	**$6,267**	$5,726
Net income	**423**	344
Cash dividends	**156**	140
Funds provided by operations	**549**	449
Taxes and Crown royalties	**1,981**	1,885
Capital and exploration expenditures	**245**	187
Capital employed at year-end	**2,746**	2,545
Total assets at year-end	**3,409**	3,288
Common shareholders' equity at year-end	**2,089**	1,822
Working capital at year-end	**1,165**	1,041
Long-term debt at year-end	**94**	87
Rate of return on average capital employed	**16.2%**	14.3%
Per Common Share Data		
Net income	**$ 3.41**	$ 2.74
Cash dividends	**1.20**	1.05
Shareholders' equity at year-end	**17.30**	15.09
Operating		
	Thousands of cubic metres daily	
Gross production of crude oil and natural gas liquids	**24.1**	23.4
Refinery input	**20.9**	21.3
Petroleum product sales	**30.2**	28.4
	Millions of cubic metres daily	
Natural gas sales	**3.2**	3.2
	Cubic metres	
Estimated gross proved recoverable reserves:		
Crude oil and natural gas liquids (millions)	**64.0**	64.9
Natural gas (billions)	**51.4**	62.8









Letter to Shareholders

Your Company continues to lead the major integrated oil companies with the highest return on average shareholder equity of 21 per cent. Our key objective is to continue to increase the value of the Company to its shareholders. Earnings for 1984 of $423 million were the best in the Company's history. Dividends per common share were increased 14 per cent to $1.20.

We are proud of the Company's 1984 accomplishments and optimistic about its future. Underlying this optimism is a strong financial position, a significant underlying resource base, and clear strategies to improve the petroleum products sector and to strengthen our energy resource sector. During 1984, 90 per cent of our gross liquid production was replaced, the highest level in several years. The acquisition of Canadian Reserve Oil and Gas Ltd. on January 2, 1985, increased our gross reserves of liquids by some 6.9 million cubic metres and our natural gas reserves by 12.4 billion cubic metres.

On February 19, 1985, Texaco Inc. made a public offering in Canada of 14 million shares of its Texaco Canada Inc. common stock. This was the largest underwritten offering of common shares of a Canadian company ever sold in the Canadian market. The strong response from Canadian investors was gratifying and indicated a recognition of the Company's fundamental strength. This offering raised the Canadian ownership of Texaco Canada shares to approximately 22 per cent with no dilution to previous shareholders.

We hope the federal government will have the wisdom to follow through positively with previously announced policy changes, including price decontrols, deregulation and the reduction of the industry's disproportionate tax burden. New initiatives can either stimulate reinvestment and job creation in Canada or continue to miss the opportunity to encourage growth in the energy sector of the nation.

Your Company will continue its multiple strategy of improving its long-term position by adding to its production and reserves through increased conventional exploration in western Canada, enhanced oil recovery, natural gas liquids extraction, foreign exploration, frontier exploration and tar sands/heavy oil projects. The tough task of downsizing refining and marketing operations is taking place with positive benefits now flowing to the Company.

The continued support of existing shareholders in addition to the overwhelming response to the February share issue by our new shareholders is greatly appreciated.

On behalf of the Board of Directors,

James L. Dunlap

James L. Dunlap,
President and Chief Executive Officer

North York, Ontario
March 26, 1985

Directors of Texaco Canada Inc.

Left to right are:
James L. Dunlap,
George W. Govier,
Charles I. Rathgeb

R. W. Sparks,
Howard J. Lang,
Jacques Bock,
William K. Tell, Jr.

James E. Brazell,
Stanley D. Clarke,
Neil M. Shaw,
Roland M. Routhier

Stuart J. Walker,
William A. Gatenby,
Rodrigue J. Bilodeau,
Peter I. Bijur

J. Lee Morrison retired as a Director and as Executive Vice-President in 1984, after 38 years of loyal service. He was succeeded as a Director by Stuart J. Walker. Mr. Walker also was appointed Senior Vice-President in 1984.

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

Exploration

Texaco Canada conducted a broadly based, diversified exploration program during 1984. As a result, the Company tripled its land holdings, carried out one of the most ambitious seismic programs in its history and participated in 70 exploratory wells. AT&S Exploration Ltd., a joint exploration company in which Texaco Canada holds a 25 per cent interest, began participating in drilling on Canadian frontier lands during the year.

Texaco Canada's seismic and drilling activities were concentrated in the western Canadian Sedimentary Basin where the Company has identified significant hydrocarbon potential. Large tracts of land were acquired in Brazil, Peru and Guinea Bissau as the Company expanded its foreign exploration activities. In Canada, 14 450 hectares were purchased in the oil prone Desan area of British Columbia.

Western Provinces

Exploratory drilling in western Canada was conducted throughout Alberta and in northeastern British Columbia. Five exploratory wells drilled in northwestern Alberta on the Doe Creek/Knopcik sand play resulted in three oil wells and one gas well.

An extensive drilling program was carried out in the greater Pembina area of west-central Alberta. Of 27 wells drilled, nine were oil discoveries and four were gas discoveries.

Several additional wells drilled near the end of 1984 are awaiting completion in 1985.

Seismic programs were conducted on a wide range of prospective plays throughout Alberta and in northeastern British Columbia. The results of these programs will lead to further exploratory drilling during 1985.

Expenditures at land sales in western Canada increased by 44 per cent over 1983, resulting in the acquisition of 48 500 gross hectares of high quality land concentrated in areas prospective for oil. Working interests were also acquired from other companies through farm-ins.

East Coast

Offshore Nova Scotia, the fourth appraisal well drilled on the Venture structure, Venture H-22, flowed gas in significant quantities from three zones. The well is located two kilometres southeast of the D-23 well where natural gas was discovered in 1979. During 1984, Texaco Canada farmed out to AT&S Exploration Ltd. half of its 18 per cent interest in two 18 000 hectare blocks on which two additional wells are being drilled in the Sable Island area.

Near year-end, drilling of an exploratory well began on the Albatross block, southeast of Nova Scotia. Under the terms of a farm-out agreement, the well is being drilled at no cost to the Company. Following completion of the drilling program, Texaco Canada's interest in the 114 000 hectare block will be 27.5 per cent.

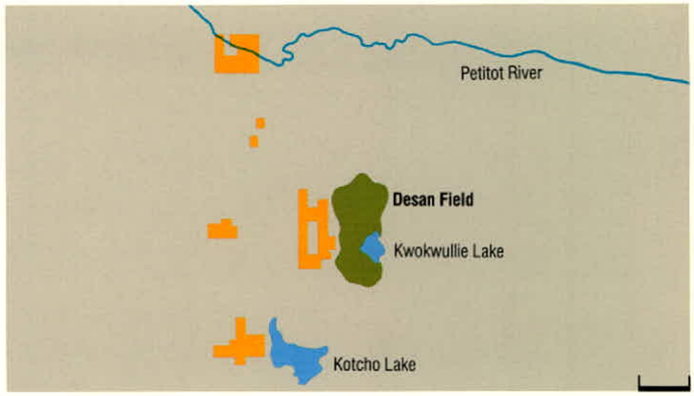
In 1984, a Chamber of the International Court of Justice reached a decision concerning the boundary between Canada and the United States in the Georges Bank area off Nova Scotia. The decision left all but 40 000 hectares of Texaco Canada's 922 000 hectare Georges Bank block under Canadian jurisdiction. Exploration on the block, which had been under suspension for a number of years pending the decision, is planned for 1985.

The Company surrendered landholdings in two offshore blocks in eastern Canada. One, a 50 per cent working interest in 1.4 million hectares of Quebec and federal permits in the Gulf of St. Lawrence, was relinquished after the drilling of a dry hole on adjacent land. The other, a 20 per cent working interest in a 728 000 hectare federal exploration agreement in the Newfoundland Basin, was surrendered following an in-depth evaluation of available technical data.

AT&S Exploration Ltd.
AT&S actively pursued exploration opportunities in 1984 through farm-ins both on Texaco Canada lands and on prospects held by other companies. South Griffin J-13, the first well on the East Banquereau block off Nova Scotia, was abandoned as a dry hole. Drilling of a second well on the block, Hesper P-52, was continuing early in 1985. AT&S will earn 50 per cent of Texaco Canada's interest in 18 000 hectares encompassing each farm-out well upon its completion.

Under another farmout from Texaco Canada, AT&S is participating in two wells evaluating gas potential west of the previous Venture tests offshore Nova Scotia. One well, West Venture N-91, experienced subsurface well control problems and efforts to regain control were continuing at year-end. The other West Venture well, C-62, was being tested early in 1985.

AT&S conducted a detailed seismic program on Texaco Canada lands in the Norman Wells area of the Northwest Territories during 1984. Two wells, by which AT&S earned a 50 per cent interest in the Texaco Canada blocks, were drilled in late 1984 and early 1985 and



Texaco Interest Lands

Desan Area

Km 0 10

Texaco Interest Lands

Effect on Texaco Canada's Georges Bank block of the International Court of Justice boundary decision.

Georges Bank

Km 0 300

Oil and Gas Rights

December 31	1984		1983	
Thousands of Hectares	**Gross**	**Net**	Gross	Net
Canada				
Western Provinces	**1 186**	**736**	1 199	725
Quebec Onshore	**120**	**120**	120	120
Eastern Canada				
Offshore	**3 644**	**2 007**	5 885	2 754
Beaufort Sea	**106**	**53**	106	53
Other	**151**	**103**	156	114
Total Canada	**5 207**	**3 019**	7 466	3 766
International				
Brazil	**16 608**	**8 304**	–	–
Peru	**1 000**	**212**	–	–
Guatemala	**198**	**33**	198	33
Guinea Bissau	**450**	**76**	–	–
Total International	**18 256**	**8 625**	198	33
Total	**23 463**	**11 644**	7 664	3 799

subsequently abandoned. The second earning well is expected to be drilled and evaluated during the first quarter of 1985.

AT&S also entered into agreements to earn working interests in frontier land in the MacKenzie Delta, the shallow water region of the Beaufort Sea, the Flemish Pass area offshore Newfoundland and in the Fort Norman area of the Northwest Territories through farm-ins from companies other than Texaco Canada. One of the farm-in wells, East Amauligak J-44, located in the Beaufort Sea, tested significant quantities of oil and natural gas. AT&S anticipates participating in over 30 frontier wells during the next two years.

Foreign

Texaco Canada significantly expanded its foreign exploration program in 1984, entering agreements in three additional countries as well as continuing its activity in Guatemala. The Company has identified potential for major oil discoveries in these areas which would contribute to Texaco Canada's reserves in the medium term.

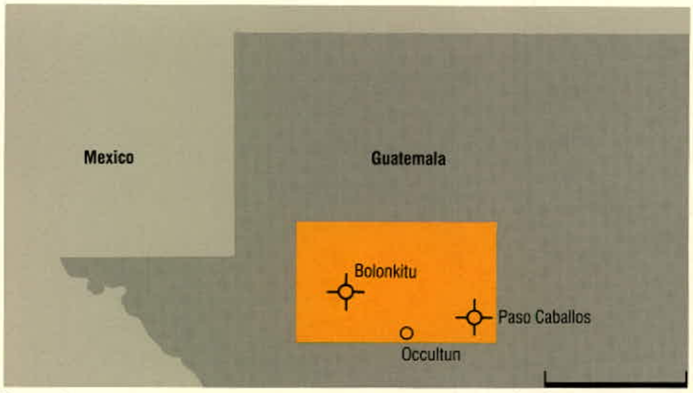
The largest foreign acquisition was a 50 per cent working interest in 16.6 million hectares in the Marajo area of northeastern Brazil. The holdings are being evaluated through aeromagnetic and seismic programs. The Company also acquired a 21.25 per cent working interest in a one million hectare block in the Oriente of Peru. Drilling of the first well on the land began in late December.

Contract requirements with the government of Guinea Bissau were satisfied by the drilling of a well off the West African country's coast. Texaco Canada earned a 16.875 per cent interest in a 450 000 hectare offshore block by participating in the well, which was abandoned in July.

In Guatemala, Texaco Canada holds a 16.67 per cent interest in 198 000 hectares. The first well on the block had an indicated oil show, but could not be tested because of technical difficulties. Early in 1985, a second well was abandoned and a third well was spudded.

Lands in Central and South America in which Texaco Canada holds an interest.

Texaco Interest Lands
Dry hole
Drilling Well



Guatemala

Peru

Brazil

Drilling began on
Mahuaca well in Peru
in late 1984.

Service company employee Greg Wansbrough and Texaco Canada Petroleum Engineer Cameron Hall adjust a well casing inspection tool.

Development

Development activities are directed towards delineation of, and maximizing recovery from, identified oil and gas reservoirs. In 1984, Texaco Canada increased its activities significantly. As a result, the number of gross development wells increased five fold and production facilities were expanded. In addition, new enhanced oil recovery projects were implemented, gas plant facilities were modified to increase the extraction of natural gas liquids and pipeline systems were extended.

Drilling

Texaco Canada participated in 176 development wells in 1984, all in western Canada. This resulted in 166 oil wells and three gas wells for an overall success rate of 96 per cent.

Four operated wells were drilled in the mature Wizard Lake field to improve productive capability. In addition, the Company operated eight wells in the Pembina area with three of these being drilled as part of enhanced oil recovery projects in the Pembina Nisku pinnacle reefs and the remaining 5 wells being drilled as delineation wells in the Cyn Pem and Pembina Cardium oil pools.

The largest number of wells was drilled in the Nipisi area northwest of Edmonton. Revisions introduced in 1983 which provided the New Oil Reference Price (essentially world price) for oil from infill wells within the Nipisi Unit resulted in 38 wells being drilled to optimize oil recovery from the field. An additional 34 wells were drilled in the Swan Hills area of north-central Alberta in preparation for the implementation of a miscible flood in 1985.

Twenty oil wells were drilled in the Valhalla area of northwestern Alberta, continuing a program begun in 1983. The majority of the remaining Alberta wells were drilled as infill wells in the Clive, Pembina and Mitsue Gilwood fields to improve recovery. In addition, 24 wells were drilled in Saskatchewan for enhanced oil recovery and infill purposes.

Enhanced Oil Recovery

Five enhanced oil recovery projects in which Texaco Canada has an interest, comprising three hydrocarbon miscible floods and two waterfloods, were implemented during the last year. Three of the projects (two hydrocarbon miscible floods and one waterflood) are in West Pembina Nisku pools in west-central Alberta.

The West Pembina miscible floods are in the Pembina Nisku "L" Pool (100 per cent Texaco-owned) and the Pembina Nisku "Q" Pool (96.125 per cent owned). Together they ultimately will add 1 150 cubic metres of production per day to the Company's total.

Texaco Canada's extensive enhanced oil recovery commitment in the West Pembina area resulted in the construction of strategically important high pressure pipelines, pump stations, and injection facilities.

The third hydrocarbon miscible flood was implemented in the Nipisi Gilwood Unit in north-central Alberta. Initiation of an expansion to this project is expected in 1985.

Pipelines
Miscible floods such as those in which Texaco Canada is extensively involved require large amounts of natural gas and natural gas liquids (NGL's) to be injected into certain wells to maintain formation pressure and to act as solvent to achieve maximum oil recovery. To supply the NGL requirements for these projects, Texaco Canada in 1984 completed construction of 145 kilometres of pipeline from the Bonnie Glen area to West Pembina, and to Wizard Lake. The pipelines are capable of delivering 2 100 cubic metres per day of NGL's to Wizard Lake, and 2 000 cubic metres per day to West Pembina.

Federated Pipe Lines Ltd. (50 per cent owned by Texaco Canada) is converting existing pipeline facilities and adding new facilities for the shipment of ethane-rich natural gas liquids from Fort Saskatchewan (northeast of Edmonton) to an enhanced oil recovery project scheduled for implementation in 1985 in the Swan Hills area of north-central Alberta.

Production Facilities
Additional equipment was installed at the West Pembina 3-28 Battery to increase the battery's capacity to handle production resulting from the implementation of enhanced oil recovery projects.

The Bonnie Glen and Wizard Lake fields have reached a mature stage of depletion, requiring the installation of further pumping equipment and water handling facilities in order to optimize production.

Natural Gas
Texaco Canada has increased its activities to supply gas for enhanced oil recovery schemes. A major increased requirement in 1984 for such gas was in the West Pembina area. Available uncontracted gas reserves were brought on stream, and excess volumes from contracts not currently being taken at full contract rate were made available.

Texaco Canada's development of gas processing facilities in 1984 concentrated on the extraction of natural gas liquids for use in enhanced oil recovery projects. At the Bonnie Glen Gas Plant, facilities were installed to liquefy ethane extracted from the natural gas. The ethane will be used primarily in the nearby Wizard Lake miscible flood.

At the Elmworth Gas Plant near Grande Prairie, construction is continuing on facilities for the extraction of ethane and heavier natural gas liquids. As a result of its 31.55 per cent interest in the facilities, Texaco Canada's natural gas liquids production capacity will increase by

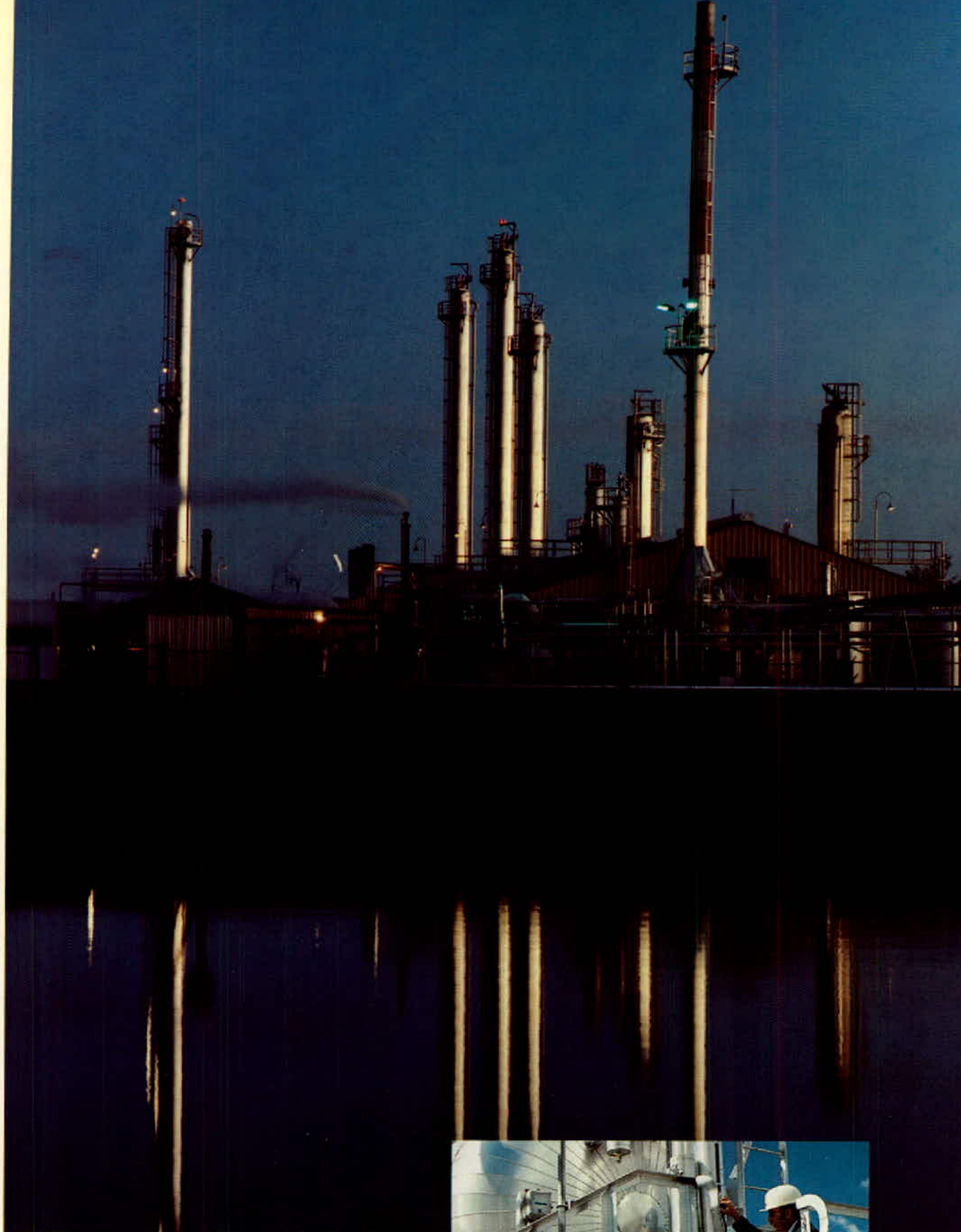
Overhead pipe supports are fabricated at Elmworth Gas Plant.

over 800 cubic metres a day. On completion of the project in 1985, the NGL's will be used in the Swan Hills miscible flood. The product will be transported by pipeline to storage at Fort Saskatchewan and then through the Federated pipeline to Swan Hills.

One gas processing plant in which Texaco Canada has an interest in the Brazeau River area of west-central Alberta was completed in May, while construction began on another in the same region during the year. The latter, to be completed in mid-1985, will allow the recovery of condensate, liquefied petroleum gas and sulphur from gas cycling operations.

Texaco Canada has been negotiating with prospective U.S. buyers to market its share of gas production from the East Sable area located offshore Nova Scotia.

A gas export application to the National Energy Board is to be followed by an NEB facilities application to construct the required gas handling pipelines. The buyer would also file applications with U.S. regulatory agencies to import the gas and build the necessary U.S. pipelines. Depending on the timing of the regulatory process and the confirmation of sufficient reserves, gas could flow by 1990 when it is projected that the current U.S. deliverability surplus will have ended.



Above:
Natural gas liquids extraction and processing facilities at Bonnie Glen.

Right:
Bonnie Glen Gas Plant Foreman Larry Kobeluck examines section of new ethane liquefaction facilities.

Production

Liquids

Texaco Canada's crude oil and natural gas liquids production increased by three per cent from the 1983 level to an average of 24 100 cubic metres per day. Production gains resulted from higher allowables, successful drilling programs and enhanced recovery schemes in the West Pembina Nisku area, offsetting naturally declining production in older fields.

Oil production from the West Pembina area increased as a result of a full year of production in 1984 from two miscible floods implemented in late 1983. The area was responsible for 12 per cent of Texaco's total oil production in 1984 compared to about nine per cent in 1983.

Natural Gas Sales

Sales of natural gas were 3.2 million cubic metres daily in 1984, essentially the same as in the previous year.

Gas sales were affected for most of the year by the uncertainty of government policy in both Canada and the United States. Under the new Canadian gas export policy announced in July, 1984, the pricing provisions on over 80 per cent of flowing licensed exports had by year-end been freely renegotiated between buyers and sellers, and had received approval from the federal government.

Reserves

The replacement ratio for crude oil and natural gas liquids in 1984 was 90 per cent of production. Reserves of natural gas liquids increased substantially in 1984 primarily as a result of the addition of ethane liquefaction facilities at the Bonnie Glen Gas Plant.

The decline of 18.7 per cent in natural gas reserves was due to the conversion of the method of reporting reserves from a "wet" gas to a "dry" gas basis and to a downward revision of Deep Basin reserves following a reevaluation based on pool performance. Dry gas reserves are those resulting from the processing of "raw" produced gas for the removal of natural gas liquids and other components entrained therein.

Oil Sands

Texaco Canada holds 227 000 net hectares of leases and permits in the oil sands deposits of Alberta, which contain an estimated 11 billion cubic metres of bitumen, a thick, tar-like hydrocarbon.

As part of an increased emphasis on exploitation of its oil sands holdings, Texaco Canada completed a nine well drilling program in late 1984 on its Frog Lake lease in the Cold Lake area of east-central Alberta. Core samples of the oil bearing formations were obtained and are currently being analyzed in the laboratory. Additional drilling is planned in 1985 to delineate further resources necessary for the design and location of possible pilot recovery operations.

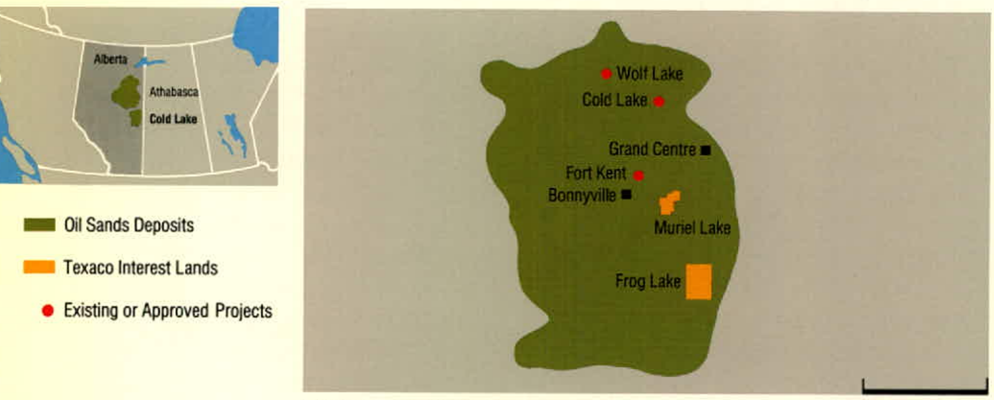
Both the Company's Frog Lake and Athabasca leases are in areas where the depth of the oil sands below ground level does not allow economic bitumen recovery by open pit mining procedures. Consequently, Texaco Canada is concentrating on developing new technology for in-situ recovery.

The development of the Company's Athabasca oil sand leases is assisted by proprietary research programs carried out by a number of agencies, notably the Alberta Research Council and the University of Alberta. The joint research efforts of Texaco Canada and the Alberta Research Council have resulted in the development of a down hole solids control filter for which a U.S. Patent has been granted and a Canadian Patent application has been made.

The device is undergoing field testing to demonstrate its efficiency and cost effectiveness for use in oil sands, heavy oil and appropriate conventional reservoirs. Texaco Canada is currently evaluating the commercialization of the filter through manufacturing licensing.

Continued activity at Texaco Canada's Fort McMurray pilot in northeastern Alberta complements these laboratory research programs in working towards the goal of developing a commercial recovery process. During 1984, activity concentrated on Patterns II and III.

Pattern III consists of three long, parallel, horizontal wells drilled to test recovery from horizontal drain holes. A down hole pump was installed in one of the wells during 1984, and the resultant bitumen recovery has been encouraging.



Cold Lake Oil Sands Deposit

A Technical Information Purchase Agreement for Pattern III data was successfully negotiated with the Alberta Oil Sands Technology and Research Authority (AOSTRA).

In Pattern II, which is nearly depleted, hot water was injected to recover bitumen mobilized by previous steam injection. Operations in this pattern are being phased out because bitumen recoveries are approaching marginal levels.

No reserves are attributed to the Company's oil sands deposits because no portion of the bitumen is currently economically recoverable.

Canadian Reserve Oil and Gas

The purchase of Canadian Reserve Oil and Gas Ltd. from a subsidiary of Texaco Inc. on January 2, 1985 substantially increased Texaco Canada's landholdings and its reserves of crude oil, natural gas liquids and natural gas.

Canadian Reserve was a wholly-owned subsidiary of Getty Oil Company which was acquired by Texaco Inc. in early 1984. The acquisition of Canadian Reserve, with its high quality producing and exploratory holdings complementing Texaco Canada's operations represents an important step in Texaco Canada's growth.

The purchase provided Texaco Canada with additional gross proved reserves of 6.9 million cubic metres of crude oil and natural gas liquids and 12.4 billion cubic metres of natural gas. Additional reserves will be added through further exploratory and development work on the acquired holdings.

Included in the Canadian Reserve liquid reserves are 1.3 million cubic metres of heavy oil, providing Texaco Canada with a heavy oil production base. Canadian Reserve holds interests in over 107 000 gross hectares of heavy oil properties.

Canadian Reserve's total land holdings in Canada amount to approximately 2.2 million gross hectares. Almost half of the land rights are located in western Canada and will provide additional opportunities for Texaco Canada's expanded exploration efforts. Both the heavy oil and conventional properties are expected to provide near-term production gains and significant reserve additions.

Exploratory drilling by Canadian Reserve in 1984 was concentrated in eastern Alberta and western Saskatchewan, northeastern British Columbia and northwestern Alberta. The 30 gross exploratory wells in which Canadian Reserve participated resulted in 10 oil wells and 6 gas wells. An additional six wells were still drilling or being evaluated at year-end.

Gross production of crude oil and natural gas liquids by Canadian Reserve averaged 1 892 cubic metres daily, an increase of 38 per cent from 1983 levels. The increase was primarily due to added production from two West Pembina miscible floods which were operational for the full year.

Canadian Reserve's sale of natural gas increased by 12 per cent in 1984 over 1983 levels to 640 thousand cubic metres per day. The increase was due to production from the Hinton and Morningside fields, which were operational for the full year.

During 1984, Canadian Reserve participated in 189 gross development wells, all in western Canada, resulting in 120 oil wells and 60 gas wells–a success rate of 95 per cent. The majority of the wells were in the Progress area northwest of Grande Prairie, Alberta, and the heavy oil area of western Saskatchewan.

Drilling in conjunction with thermal recovery pilot projects at Lone Rock and Eyehill in Saskatchewan accounted for 21 of the development wells. Most of the other development activity was directed towards infill drilling and pool extensions in the Manito-Marsden and Ear Lake areas of Saskatchewan and the Bodo-Hayter area of Alberta.

As part of Canadian Reserve's commitment to develop its extensive heavy oil properties through enhanced recovery, a steam pilot project was constructed at Lone Rock, Saskatchewan during 1984. The recovery of oil in place is expected to be 40 per cent compared to 5 per cent under primary depletion.

Canadian Reserve also holds a 1.6 per cent interest and a 33.3 per cent interest respectively in the Aberfeldy and Eyehill thermal recovery pilot projects in Saskatchewan. The drilling of the first well of the nine well Bodo steam pilot in Alberta commenced in late 1984. Canadian Reserve has a 6.25 per cent interest in this experimental project which is anticipated to be on stream by the end of 1985. Success in these thermal pilot projects will provide support necessary for expansion of the existing projects and the initiation of new projects, both of which could result in significant increases in reserves and production.

Producing wells in Canadian Reserve's Lone Rock Steamflood Pilot Project.

From left,
Stuart J. Walker,
Senior Vice-President;
Leslie F. Tye, Vice-President, Refining;
Norman E. Taylor,
Vice-President,
Marketing.

Marketing

A continuing decline in overall consumer demand for petroleum products and severe retail price competition in some parts of Canada, particularly Ontario, led to increased emphasis on productivity in 1984 through consolidation, technology and overall improved methods of operation.

The company continued to rationalize its service station network in 1984 through the System 2000 program in preferred markets and through the closing of low volume high cost outlets. The total number of retail service stations was reduced from 2,661 to 2,497 as a result of closures and new outlets.

The opening of 12 System 2000 service stations in 1984 marked a major step in the company's program to upgrade its marketing facilities across Canada. The System 2000 stations feature high volume pump islands and "families of buildings" housing convenience food stores, car washes or service bays, and the most modern electronic equipment. Stations which have been converted to the System 2000 concept have experienced outstanding volume increases. Potential sites for System 2000 stations are identified through a sophisticated computer model.

A $2 million expansion and automation of the Calgary Refined Products Terminal in 1984 makes the facility the company's largest and most technologically advanced distribution facility. The improvements enable the terminal to handle a tripling of throughput created through the negotiation of new supply arrangements.

Studies were launched during the year for a pilot project to develop and implement an automated marketing system at key service station outlets. The system will incorporate such features as electronic financial and inventory control systems.

A new lubricant profit centre was established to emphasize this market segment. It includes engineering services and the production, packaging and marketing of Texaco oils, greases and specialty products.

In the wholesale market, a detailed analysis was completed which will assist in streamlining this phase of petroleum marketing, and implementation is planned for 1985.

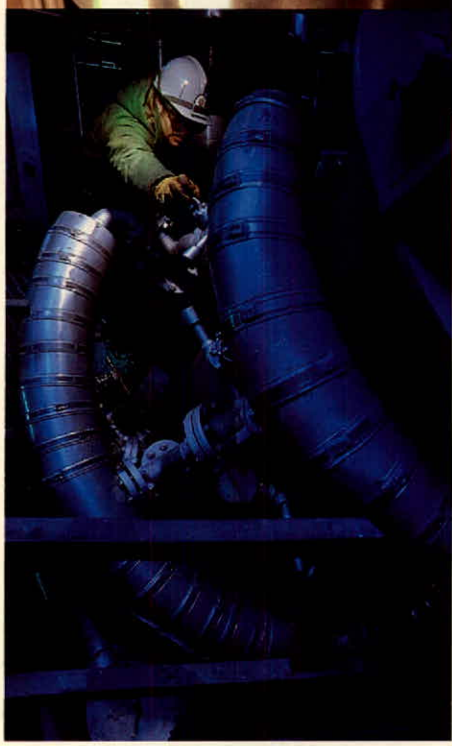
A new credit card descriptive billing system was introduced during the year in which credit card customers receive statements listing credit card transactions for the billing period instead of copies of each credit card invoice. This innovation lays the groundwork for the introduction of an electronic billing system.

The Company's sales of petroleum products, including sales under reciprocal arrangements, averaged 30 200 cubic metres daily during 1984 compared with 28 400 cubic metres daily in 1983, an increase of about seven per cent.

Texaco Canada supplying diesel fuel to the Polish tall ship Dar Mlodziezy.

New System 2000 service stations provide one-stop shopping for petroleum and automotive products, groceries, and car washes.

New fractionation apparatus tests crude oil at Nanticoke Plant laboratory.



New multi part feed injection nozzle at Nanticoke Plant's fluid catalytic cracking unit improves the unit's clean product yield.

Refining

Considerable progress was made during 1984 toward making the Company's refineries more efficient and cost effective. This continuing upgrading program employs advanced technology to achieve two major goals–the reduction of energy consumption, and the improvement of product yields.

Computerization of the refining processes helps to produce greater quantities of the lighter, more valuable products, such as gasoline, from every barrel of crude oil processed. A computer-centred instrument system also increases energy efficiency by continually monitoring and adjusting refining processes to optimum levels not attainable by manual supervision.

These programs at Nanticoke Plant helped produce savings during the year of $10 million through improved product yields and $1.5 million through energy conservation. The installation of computer controls was completed on the crude stilling and vacuum unit in 1984, and similar work on the fluid catalytic cracking, catalytic reforming, alkylation, and sulphur recovery units is scheduled for completion in 1985.

Another extremely cost effective investment was a $1 million computerized material management and maintenance planning and scheduling system brought into operation in 1984. The improved productivity provided by this system is yielding savings at the rate of about $1 million per year.

At Halifax Plant improvements in energy efficiency and clean product yield have produced savings of more than $2 million per year.

The Company's 4 450 cubic metre per day Edmonton Plant, which was too small to continue operating competitively in the changing market, ceased refining operations in April, 1984. Texaco Canada continues to supply products to its Alberta customers under supply arrangements completed with Gulf Canada Limited.

Refinery input averaged 20 900 cubic metres daily in 1984, a decrease of 1.9 per cent from the level of 21 300 cubic metres daily in 1983. The decline reflects the closing of Edmonton Plant and shutdowns of five weeks each at the Halifax and Nanticoke refineries for major scheduled maintenance. The Halifax and Nanticoke plants ran at close to full capacity during 1984 exclusive of the maintenance shutdown periods.

Supply and Distribution

New computer applications were developed during the year to improve downstream profitability by increasing the efficiency of the company's supply and distribution operations.

A computerized on line inventory management system began integrating the monitoring of all product flows such as sales, exchanges, product transfers, and in transit volumes, as well as inventory levels at all company locations.

The Supply Group implemented a computer program to support crude and petroleum product trading activities. The program ranks crude oil values based on yield and spot purchase prices, and allows the relative economics of domestic refined products and imported products to be quickly determined. The system increases the company's flexibility in responding to volatile markets.

The Company purchased certain assets of Texaco Chemicals Canada Limited from Texaco Inc. in 1984, and began distributing a line of specialty chemicals in Canada. All petrochemical and natural gas liquids activities were consolidated under the control of the Petrochemicals and N.G.L.(s). Division within the Supply and Distribution Department. The group operates as a profit centre, enhancing the Company's position in the substantial North American petrochemical and natural gas liquids markets.

The Company began product throughput operations during the year for Gulf Canada Limited at the Texaco Canada refined products terminal in Calgary. Gulf began processing products for Texaco at its Edmonton and Montreal refineries as well as terminalling for Texaco at its Clarkson facility. Texaco began processing for Gulf at Nanticoke Plant.

Texaco Canada realized significant savings as a result of these agreements. Additional savings will be achieved in 1985 as Gulf begins product throughput operations for Texaco at its facility in Burnaby, British Columbia.

The Company's supply operations in 1984 involved the transportation of an average of 42 600 cubic metres of crude oil and petroleum products daily, compared with 44 500 cubic metres daily in 1983. This total volume included the movement of 21 700 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 20 900 cubic metres daily.

Company-owned vessels carried an average 2 400 cubic metres of crude oil and products daily. Vessels chartered by the Company transported an additional 2 700 cubic metres daily.

The Alberta Products Pipeline system, in which Texaco Canada holds a 20 per cent interest, transported a daily average of 7 500 cubic metres of petroleum products.

Trans-Northern Pipelines Inc. one-third owned by Texaco Canada, carried 23 400 cubic metres of petroleum products daily. Through this system, products can be delivered to the Ottawa area from refining centres in either Montreal or Nanticoke.

A daily average of 9 900 cubic metres of imported crude oil was moved through the Montreal Pipe Line system, 16 per cent owned by Texaco Canada, to refineries in Montreal from its east coast terminal facilities in Portland, Maine.

Federated Pipe Lines Ltd., 50 per cent owned by Texaco Canada, carried 20 100 cubic metres daily of crude oil from Alberta producing fields to Edmonton refineries.

Texaco Canada's Rimbey-Edmonton Oil Pipeline carried an average of 26 700 cubic metres of crude oil daily from central Alberta to Edmonton.

The Texaco Mile provided tough competition for both Texaco Canada employees and the world's top runners.

Public Affairs

Texaco Canada's communications activities reached their highest levels ever in 1984 as the company addressed diverse audiences on a wide variety of subjects.

The company launched a television advertising campaign designed to increase public awareness of Texaco Canada and its new System 2000 service stations. The messages, designed for major markets across the country, underlined the Company's commitment to remain a major marketer of petroleum products in Canada.

The Company increased its support to organizations across Canada in the fields of education, health and welfare, arts and culture, community service, and youth work.

Texaco Canada hosted seven historic performances by the Metropolitan Opera at the Toronto International Festival in 1984 as part of the Ontario bicentennial celebrations. It also began its 45th consecutive season of sponsoring live Metropolitan Opera radio broadcasts and its second year of Canadian Opera Company broadcasts on the Canadian Broadcasting Corporation's English and French radio networks. Other sponsored events included The Texaco Mile, the National Young Drivers Rally, the Texaco Invitational at Spruce Meadows, the Drummondville Folklore Festival, and various events surrounding the 450th anniversary of Quebec and the arrival of the Tall Ships at Quebec.

A Speakers' Bureau was activated during the year with 38 senior executives and managers receiving training in public speaking and media relations techniques. Press coverage of Bureau activities enabled the company to express its views on product pricing, petroleum industry taxation, the National Energy Program, Canadian crude oil self sufficiency and other matters to a much larger audience. Speakers' Bureau activities are being expanded in 1985.

The installation of an in-house audio visual production studio helped increase the effectiveness and scope of communications with employees. The President and Chief Executive Officer launched an internal communication video series titled "People and Programs" highlighting the activities of the company in all parts of Canada. Other video presentations highlighted the Company's donations and promotions programs.

Texaco Canada's Government Relations activities have supported the federal government's policy of ensuring that there is wide consultation between government and the private business sector on important public policy issues. Subjects of interest to Texaco, including proposed modification of the National Energy Program, gasoline tetraethyl lead usage and auto emissions, were discussed with the federal government in order to develop mutual understanding of regulatory effects on Company operations, reinvestment and job creation. The company-government consultation process is also practised at the provincial and municipal levels of government.

Events which the Company sponsored or participated in included (top) National Young Drivers Rally; (centre) Molson International Car Race at Sanair, Quebec; (bottom left) Quebec tourist guides; (bottom right) Wayne Gretzky Celebrity Tennis Classic.

Employee Relations

Texaco Canada had a total of 3,635 employees at year-end, compared with 3,904 at December 31, 1983. Payroll and benefit plan costs of $171 million were 1.7 per cent lower in 1984 than in 1983.

Relocation counselling for the 225 Edmonton Plant employees and the 50 Montreal Terminal employees affected by the shutdown of these operations continued during the year. At year end, more than 80 per cent of these employees had either found employment or were receiving a pension. Retirement counselling was made available to employees of the Refining and Marketing Departments who were offered the Voluntary Early Retirement Incentive Plan.

These staff reductions, combined with normal retirements at age 65, resulted in a total of 116 employees beginning to draw benefits under the Company's pension plan during the year.

During 1984, retirement pensions and spouses' benefits paid out under the Company's Pension Plan to almost 1,100 people totalled about $7.5 million. The Company's Life Insurance Plan paid out benefits totalling $944,000.

Thirty-eight employees received their 25-year Service Awards in 1984. There were 523 active employees with 25 or more years of Company service at the end of 1984.

At year-end, 105 children of employees held active scholarships awarded under the Company's Merit Scholarship Program. These provide tuition assistance to selected students who successfully complete each year to a maximum of four years in a degree course.

Continued emphasis was placed on employee health and fitness during the year. Company-sponsored external and in-house fitness programs received an enthusiastic response and wide participation from employees.

All 15 collective labour agreements were successfully renegotiated in 1984 without work stoppage. These agreements were negotiated with six different unions representing 378 employees in the Refining and Marketing Departments. During these negotiations the Company maintained its policy of encouraging open dialogue in order to continue achieving improvements in labour relations, productivity and efficiency.

In-house fitness programs received enthusiastic employee participation.

Index to Financial Section

Net Income

Consolidated net income for the year ended December 31, 1984 was $423 million compared with $344 million in 1983 and $275 million in 1982. Net income per common share was $3.41 in 1984 compared with $2.74 in 1983 and $2.15 in 1982.

The 1984 results included charges amounting to $21 million associated with the ceasing of refining operations at Edmonton and the closing of terminal facilities. Similarly, 1983 net income included the write-off of the Montreal East terminal facilities and a marine vessel totalling $15 million. Net income for 1982 included charges of $22 million associated with the shutdown of surplus refining capacity, principally the Montreal East plant and the favourable impact of an upward revaluation of inventory due to a revision in estimates of the crude oil component included in inventory. As a result of the refining rationalization plan, long-term supply arrangements with another refiner were implemented in 1984. Pursuant to these arrangements Texaco Canada obtains refined products for its customers in Alberta and Quebec and in turn supplies refined products to that refiner in Ontario.

A significant turnaround in the operating results of the petroleum products segment and the continued improved performance of the energy resources segment contributed to the higher operating income in 1984 compared to 1983. The improvement in operating income in 1983 compared to 1982 resulted largely from the energy resources segment and was partially reduced by the operating losses in the petroleum products segment which were caused by intense price competition.

The rate of return on average capital employed increased to 16.2% in 1984, from 14.3% in 1983 and 12.2% in 1982.

Revenues from sales and services amounted to $6.2 billion in 1984, $5.7 billion in 1983 and $4.8 billion in 1982.

A discussion of the impact of changing prices on the Corporation's results of operations and financial position is set out on pages 40 and 41.

Segmented Net Income

The energy resources segment operating income was $373 million in 1984, $347 million in 1983 and $234 million in 1982. The improvement in operating income in 1984 compared to 1983 resulted primarily from higher crude oil and natural gas liquids production and higher prices for crude oil and natural gas, partially offset by higher energy costs attributable to increased miscible flood activity and an increase of $13 million in the Petroleum and Gas Revenue Tax (PGRT). Higher production reflected increased demand by refiners for crude oil, increased exports, new enhanced recovery projects and new well completions, offsetting naturally declining production in older fields. Higher crude oil prices were realized because of an increase in the New Oil Reference Price (NORP), which approximates world prices, and because a greater portion of the Corporation's crude oil production qualified for NORP.

The $113 million increase in the energy resources segment operating income in 1983 compared to 1982 was mainly due to increased crude oil and natural gas liquids production, lower provincial royalty rates on crude oil production and higher prices for crude oil and natural gas liquids. These factors were partially offset by reduced natural gas sales volumes and higher operating expenses, in particular the PGRT which increased $34 million. Higher industry crude oil exports authorized during 1983 accounted for most of the increased crude production in 1983.

Depreciation, depletion, and amortization charges were $44 million in 1984, $44 million in 1983 and $34 million in 1982. The increase in 1983 was principally due to higher amortization of non-productive leases.

Petroleum products operating income before write-offs in 1984 was $18 million. This compared to an operating loss on the same basis of $46 million in 1983 and an operating income of $31 million in 1982. A general improvement in petroleum product margins was the main factor in the return to profitability in this segment. The decline in operating results in 1983 compared to 1982 was largely attributable to lower product margins caused by intense competition in the marketplace especially for retail gasoline in Ontario and Quebec which prevailed through most of 1983.

Additionally, operating results for 1984 and 1983 were impacted by rate changes in the Petroleum Compensation Charge which resulted in inventory profits in 1984 and losses in 1983.

Taxes and Crown Royalties

Taxes and Crown royalties, including taxes collected for governments, amounted to $1,981 million in 1984, $1,885 million in 1983 and $1,883 million in 1982.

The aggregate amount of these taxes and Crown royalties in 1984 was equivalent to 4.7 times the net income and nearly 13 times the amount that preferred and common shareholders received as dividends. Income taxes increased to $526 million in 1984 from $446 million in 1983 and $389 million in 1982. The effective income tax rate was 55% in 1984, 56% in 1983 and 59% in 1982. A detailed analysis of taxes and Crown royalties is contained in the Five-Year Review on page 24.

Capital and Exploration Expenditures

Total capital and exploration expenditures in 1984 increased significantly compared to the previous two years. Expenditures on exploration and production increased in an aggressive effort to maintain the Corporation's production capability and to find profitable new reserves. This is evidenced by the total number of exploratory and development wells drilled which was 246 in 1984 compared to 92 in 1983 and 58 in 1982. The Corporation's commitment to the gasoline business is reflected in the 1984 marketing expenditures, which increased mainly pursuant to a program to remodel its retail outlets.

In conjunction with Foreign Investment Review Act approval obtained in respect of the acquisition of Canadian Reserve Oil and Gas Ltd. (Canadian Reserve), the Corporation has undertaken to make capital and exploration expenditures of $800 million (inclusive of the acquisition cost of Canadian Reserve) in 1985, and $300 million in each of the years 1986 through 1988 inclusive. Subject to meeting certain conditions, this period may be extended beyond 1988.

Capital and Exploration Expenditures

Years ended December 31	1984	1983	1982
	Millions of Canadian dollars		
Exploration and production	**$161**	$128	$134
Manufacturing	**23**	18	28
Marketing	**50**	36	30
Other	**11**	5	5
Total capital and exploration expenditures	**245**	187	197
Deduct: Exploration expenditures and development dry holes charged against current income	**44**	52	56
Total expenditures capitalized	**$201**	$135	$141

Liquidity and Capital Resources
The Corporation continued in 1984 to maintain and improve its strong liquidity position, as evidenced by the level of working capital, the current ratio, and other generally applied balance sheet and cash flow ratios. During 1984, funds required for capital expenditures, dividend payments and the redemption of preferred stock were entirely generated from funds provided by operations. It is anticipated that the strong liquidity position will continue in 1985 and that working capital will provide adequate support for the ongoing operations. In addition to the strong year-end 1984 cash, cash investments and marketable securities position, the Corporation's liquidity is enhanced by the nature of its accounts receivable and inventories. Rapid turnover of accounts receivable resulting from sound credit and collection policies and prudent collection follow-up, make these receivables highly liquid. Inventories of crude oil and petroleum products are, in the normal course of business, readily convertible to cash.

On January 2, 1985 Texaco purchased Canadian Reserve from a subsidiary of Texaco Inc. This acquisition has been fully funded from cash reserves. For additional information on this acquisition reference is made to other sections of this Report and to Note 15 to the Consolidated Financial Statements.

The Corporation has ample capacity to maintain liquidity and provide capital resources by virtue of its capacity to borrow. Continuing strong earnings again in 1984 has given the Corporation the availability of funds necessary to support planned increases in capital investment.

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 of dividends paid per common share was $1.20 in 1984, $1.05 in 1983, and $1.00 in 1982.

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:

1984	Price Range		Dividends
Quarter	High	Low	Paid
First	**$41½**	**$37½**	**$0.30**
Second	**39¾**	**36**	**0.30**
Third	**41**	**33⅞**	**0.30**
Fourth	**41¼**	**35**	**0.30**

1983	Price Range		Dividends
Quarter	High	Low	Paid
First	$32⅜	$26¼	$0.25
Second	38	29¾	0.25
Third	41	36⅛	0.25
Fourth	42¾	36⅝	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:

1984	Price Range		Dividends
Quarter	High	Low	Paid
First	**$33**	**$29⅞**	**$0.24**
Second	**31⅛**	**27½**	**0.23**
Third	**31½**	**25½**	**0.23**
Fourth	**31⅛**	**26¾**	**0.23**

1983	Price Range		Dividends
Quarter	High	Low	Paid
First	$26¼	$21⅞	$0.20
Second	31	24⅛	0.20
Third	33	29½	0.20
Fourth	34¾	30	0.24

On January 31, 1985, there were 4,029 individual, financial and other institutional holders of the Corporation's common shares. This compares with a total on December 31 of 4,045 in 1984, 4,338 in 1983, and 5,049 in 1982. In February 1985, Texaco Inc. announced a public offering for the sale in Canada of 14 million common shares in Texaco Canada Inc.

Common Shareholders' Equity
Common shareholders' equity was $2,089 million or $17.30 per share, $1,822 million or $15.09 per share and $1,617 million or $13.40 per share as at December 31, 1984, 1983 and 1982 respectively. Net income for the year 1984 represented a 21.0% return on average shareholders' equity which was higher than the return of 19.2% for 1983 and 16.7% for 1982.

Financial Summary	1984	1983	1982	1981	1980
	Millions of Canadian dollars except where noted				
Revenues					
Sales and services	**$6,156**	$5,652	$4,768	$4,375	$3,503
Investment and other income	**111**	74	74	86	69
	6,267	5,726	4,842	4,461	3,572
Net income	**423**	344	275	316	373
Per common share (dollars)	**3.41**	2.74	2.15	2.45	2.92
Per dollar of revenues (cents)	**6.8**	6.0	5.7	7.1	10.5
Dividends paid or accrued					
Common shares	**145**	127	121	99	70
Per common share (dollars)	**1.20**	1.05	1.00	0.82	0.585
Second preferred shares: Series A	**11**	13	13	13	13
Series B	**–**	–	2	7	9
Funds provided by operations	**549**	449	384	404	461
Capital and exploration expenditures	**245**	187	197	209	224
Taxes and Crown royalties					
Income taxes	**526**	446	389	370	341
Federal sales tax	**137**	138	139	135	98
Petroleum and gas revenue tax	**182**	169	135	72	–
Petroleum compensation charge	**261**	256	391	513	101
Crown royalties	**380**	361	335	289	242
Other taxes and levies	**58**	51	55	50	41
	1,544	1,421	1,444	1,429	823
Motor fuel and excise taxes collected for governments	**437**	464	439	372	318
	$1,981	$1,885	$1,883	$1,801	$1,141
Financial Position (at year-end)					
Capital employed					
Current assets	**$1,828**	$1,784	$1,466	$1,397	$1,198
Current liabilities	**663**	743	631	640	537
Working capital	**1,165**	1,041	835	757	661
Net properties, plant, and equipment	**1,372**	1,300	1,290	1,280	1,204
Investments, long-term receivables and other assets	**209**	204	210	202	201
	2,746	2,545	2,335	2,239	2,066
Total assets	**3,409**	3,288	2,966	2,879	2,603
Long-term debt	**94**	87	83	86	98
Deferred gas production revenue and other income	**72**	63	54	16	11
Deferred income taxes	**401**	403	410	408	384
Redeemable preferred stock	**90**	170	170	250	290
Preferred stock	**–**	–	1	1	3
Common stock and retained earnings	**2,089**	1,822	1,617	1,478	1,280
Equity per common share (dollars)	**17.30**	15.09	13.40	12.25	10.62
Rate of return on average capital employed	**16.2%**	14.3%	12.2%	14.9%	19.9%
Current ratio	**2.8**	2.4	2.3	2.2	2.2
Share Ownership (at year-end)					
Common shares outstanding (thousands)	**120,768**	120,768	120,684	120,681	120,569
Common shareholders	**4,045**	4,338	5,049	5,366	5,592
First preferred shares outstanding	**–**	–	10,759	11,197	25,198
First preferred shareholders	**–**	–	87	132	308

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

Operations Statistical Summary	1984 Gross	1984 Net	1983 Gross	1983 Net	1982 Gross	1982 Net	1981 Gross	1981 Net	1980 Gross	1980 Net
Production										
Crude oil (thousands of cubic metres daily)	**21.8**	**14.2**	20.8	13.7	20.5	12.9	21.2	12.9	21.9	13.5
*Natural gas liquids (thousands of cubic metres daily)	**2.3**	**2.3**	2.6	2.6	2.5	2.5	2.3	2.3	2.1	2.1
*Natural gas (millions of cubic metres daily)	**3.6**	**2.0**	3.8	2.3	4.3	2.6	4.0	2.3	3.1	1.8
Estimated Proved Reserves (at year-end)										
Crude oil (millions of cubic metres)	**45.6**	**30.5**	50.8	33.8	53.1	35.4	58.5	36.5	67.9	42.7
Natural gas liquids (millions of cubic metres)	**18.4**	**13.0**	14.1	10.0	14.0	9.9	13.3	9.3	13.7	9.7
**Natural gas (billions of cubic metres)	**51.4**	**36.0**	62.8	44.4	63.3	44.7	65.2	44.3	60.9	43.7
Oil and Gas Landholdings (at year-end) (thousands of hectares)										
Producing	**507**	**231**	489	223	482	232	488	237	480	230
Undeveloped	**22956**	**11413**	7175	3576	6481	3416	6751	3695	5595	3215
Total	**23463**	**11644**	7664	3799	6963	3648	7239	3932	6075	3445
Wells Drilled										
Exploratory wells										
Oil	**21**	**9.5**	14	6.1	6	4.4	6	4.6	4	3.1
Gas	**12**	**4.3**	9	5.9	6	5.1	8	3.7	13	2.7
Dry	**37**	**17.5**	35	18.9	17	9.4	19	9.2	12	4.6
Development wells										
Oil	**166**	**38.3**	28	18.0	17	12.5	29	12.3	76	18.3
Gas	**3**	**1.8**	3	1.0	8	4.5	46	11.7	131	39.9
Dry	**7**	**1.2**	3	2.3	4	2.2	6	1.7	4	2.5
Total	**246**	**72.6**	92	52.2	58	38.1	114	43.2	240	71.1
Wells in the Process of Drilling (at year-end)	**12**	**4.7**	9	4.1	10	3.9	4	3.2	15	9.9
Wells Capable of Producing (at year-end)										
Oil	**5016**	**1132**	4883	1077	4806	1029	4819	1022	6184	1297
Gas	**1172**	**298**	1177	293	1245	306	1173	288	1125	276
Multiple completions included in the above	**150**	**18.8**	136	15.6	137	16.5	136	15.6	126	17.4

Refining and Sales	1984	1983	1982	1981	1980
***Refinery input (thousands of cubic metres daily)	**20.9**	21.3	23.5	28.2	29.8
†Refinery crude oil capacity at year-end (thousands of cubic metres daily)	**18.3**	22.7	22.7	34.6	33.9
Petroleum product sales (thousands of cubic metres daily)	**30.2**	28.4	28.0	31.6	33.8
Natural gas sales (millions of cubic metres daily)	**3.2**	3.2	3.7	3.3	2.4
Employees					
Number at year-end	**3,635**	3,904	4,418	4,522	4,442
Payroll and benefits (millions of Canadian dollars)	**$ 171**	$ 174	$ 165	$ 147	$ 126

*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 refineries 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 2.3 thousand cubic metres daily.

†Refinery crude oil capacity at December 31, 1980 through 1983 included the refinery crude oil capacity at Edmonton, Alberta and at December 31, 1980 and 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. 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 a new 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.

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.

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. Amounts charged to pension expense are based on amortizing the cost of pension benefits on an actuarial basis over the remaining estimated service of the employees involved.

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	1984	1983	1982
	Millions of Canadian dollars except per share data		
Revenues			
Sales and services	**$6,156**	$5,652	$4,768
Investment and other income	**111**	74	74
	6,267	5,726	4,842
Deductions			
Cost of sales and operating expenses	**4,590**	4,211	3,495
Selling, general and administrative expenses	**175**	180	168
Maintenance and repairs	**58**	53	59
Exploration expenses and development dry holes	**44**	52	56
Depreciation, depletion, and amortization	**85**	83	72
Interest charges	**9**	9	9
Petroleum and gas revenue tax	**182**	169	135
Taxes, other than income taxes (Note 11)	**175**	179	184
	5,318	4,936	4,178
Income before Income Taxes	**949**	790	664
Income Taxes (Note 12)			
–current	**525**	438	391
–deferred	**1**	8	(2)
	526	446	389
Net Income	**$ 423**	$ 344	$ 275
*Net income per common share	**$ 3.41**	$ 2.74	$ 2.15
Retained Earnings			
Beginning of year	**$1,785**	$1,581	$1,442
Add–Net income	**423**	344	275
Deduct–Dividends on preferred shares	**11**	13	15
–Dividends on common shares	**145**	127	121
End of year	**$2,052**	$1,785	$1,581
Cash dividends per share			
First Preferred, Series A	**$ –**	$ 4.52	$ 6.00
Second Preferred, Series A	**7.50**	7.50	7.50
Second Preferred, Series B	**–**	–	5.44
Common	**1.20**	1.05	1.00

*Net income per common share is based on the average number of common shares outstanding (120,768,176 shares in 1984, 120,699,735 shares in 1983 and 120,683,439 shares in 1982).

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

December 31	1984	1983
	Millions of Canadian dollars	
Assets		
Current Assets		
Cash	$ 83	$ 7
Cash investments and marketable securities, at cost, which approximates market value	340	539
Accounts and notes receivable, less allowance for doubtful accounts of $6 in 1984 and $8 in 1983 (includes a note receivable from an affiliate of $264 in 1984) (Note 2)	878	650
Inventories (Note 3)	501	564
Prepaid expenses and deferred income taxes	26	24
Total current assets	1,828	1,784
Investments and Advances (Note 4)	180	180
Properties, Plant, and Equipment (Notes 5 and 9)	1,372	1,300
Deferred Charges	29	24
Total	$3,409	$3,288
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable	$ 393	$ 417
Accrued liabilities	99	88
Income and other taxes payable	164	234
Other	7	4
Total current liabilities	663	743
Long-term Debt (Note 6)	94	87
Deferred Gas Production Revenue and Other Income	72	63
Deferred Income Taxes	401	403
Redeemable Preferred Stock (Note 7)	90	170
Common Stock and Retained Earnings		
Common stock—Issued and outstanding: 120,768,176 shares (Note 8)	37	37
Retained earnings	2,052	1,785
Total common stock and retained earnings	2,089	1,822
Total	$3,409	$3,288

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

Jacques Bock, Director

Consolidated Statement of Changes in Financial Position

Years ended December 31	1984	1983	1982
	Millions of Canadian dollars		
Source			
Net income	$423	$344	$275
Depreciation, depletion, and amortization	85	83	72
Write-off of non-operating manufacturing assets, terminal facilities and marine vessel, before deferred income taxes	38	31	41
Income taxes—deferred	(2)	(7)	2
Other	5	(2)	(6)
Provided by operations	549	449	384
Investments and advances (net)	3	12	–
Properties, plant, and equipment retirements, sales, and investment tax credits	6	11	18
Deferred gas production revenue	1	9	38
Long-term debt	10	9	–
	569	490	440
Disposition			
Properties, plant, and equipment expenditures	201	135	141
Long-term debt	3	5	3
Redeemable preferred stock	80	–	80
Dividends	156	140	136
Changes in working capital, excluding funds			
Accounts and notes receivable	228	101	48
Inventories	(63)	44	(63)
Accounts payable	24	(136)	18
Accrued liabilities	(11)	4	9
Income and other taxes payable	70	20	(18)
Other	(1)	(13)	9
Other net disposition	5	4	2
	692	304	365
Funds			
Increase (decrease) for year	(123)	186	75
Beginning of year	546	360	285
End of year	$423	$546	$360

Funds are defined as cash and cash investments and marketable securities.

See accompanying Description of Significant Accounting Policies and 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. Related Party Transactions

Accounts and notes receivable 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. Additionally, amounts due from an affiliated company under direct financing leases are shown in Note 4.

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.

3. Inventories

December 31	1984	1983
Crude oil	**$150**	$164
Petroleum products and other merchandise	**341**	390
Materials and supplies	**10**	10
Total	**$501**	$564

4. Investments and Advances

December 31	1984	1983
Non-subsidiary companies accounted for:		
On equity method	**$ 32**	$ 20
At cost	**1**	1
	33	21
Other investments		
Direct financing leases–affiliated company	**142**	144
Notes, mortgages and other long-term receivables	**5**	15
Total	**$180**	$180

Texaco Canada's equity in the net income of the non-subsidiary companies accounted for on the equity method aggregated $3 in 1984, $6 in 1983, and $5 in 1982. Dividends received from companies accounted for by this method amounted to $8 in 1984, $6 in 1983, and $5 in 1982. Undistributed income of these non-subsidiary companies included in Texaco Canada's retained earnings amounted to $11 as at December 31, 1984 and $16 as at December 31, 1983.

5. Properties, Plant, and Equipment

	Cost		Accumulated depreciation, depletion, and amortization	
December 31	1984	1983	1984	1983
Exploration and production	**$ 947**	$ 836	**$326**	$286
Manufacturing	**580**	639	**118**	137
Marketing	**411**	361	**159**	144
Marine	**17**	16	**6**	5
Pipelines	**12**	12	**6**	6
Other	**32**	25	**12**	11
Total	**$1,999**	$1,889	**$627**	$589
Net properties, plant, and equipment	**$1,372**	$1,300		

6. Long-term Debt

December 31	1984	1983
10¾% debentures, 1974 series, due 1994 ($5 annual sinking fund requirement 1985-1993)	**$ 75**	$80
5% debentures, from joint venture partner, due not later than 1997	**19**	9
Capital lease obligations (Note 9)	**6**	8
	100	97
Less:		
10¾% debentures held for sinking fund requirements	**5**	8
Capital lease obligations due within one year included in other current liabilities	**1**	2
Total	**$ 94**	$87

7. Redeemable Preferred Stock

December 31	1984	1983
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: 1984, 900,000 shares and 1983, 1,700,000 shares	**$90**	$170

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

Millions of Canadian dollars except per share data

7. Redeemable Preferred Stock (continued)

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 1984 a total of 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.

8. Capital Stock

December 31	1984	1983
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 redemp-ion 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, 1984, 1983 and 1982, the following changes were reflected in the number of common shares and First Preferred Shares, Series A:

	1984	1983	1982
Common Shares			
Outstanding at beginning of year	120,768,176	120,684,376	120,680,872
Add:			
Conversion of First Preferred Shares into Common Shares	–	83,800	3,504
Outstanding at end of year	120,768,176	120,768,176	120,684,376
First Preferred Shares, Series A			
Outstanding at beginning of year	–	10,759	11,197
Deduct:			
Conversion of First Preferred Shares into Common Shares	–	10,475	438
Redemption of First Preferred Shares	–	284	–
Outstanding at end of year	–	–	10,759

9. Capital Leases, Lease Commitments and Rental Expense

As at December 31, 1984 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 consid-ered 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	1984	1983
Land	$ 9	$ 9
Buildings and equipment	20	23
	29	32
Less: Accumulated amortization	18	20
Net capital leases	$11	$12

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

Future minimum lease payments on non-cancellable operating leases and capital leases as at December 31, 1984 are:

	Operating Leases	Capital Leases
1985	**$12**	**$2**
1986	**11**	**1**
1987	**9**	**1**
1988	**6**	**1**
1989	**5**	**1**
After 1989	**11**	**3**
Total minimum lease payments	**$54**	**9**
Less: Amount representing interest		**3**
Present value of capital lease obligations (Note 6)		**$6**

Future minimum rental income from non-cancellable sub-leases amount to $21 in respect of operating leases and $7 in respect of capital leases.

Rental expense comprises:

Years ended December 31	1984	1983	1982
Minimum rentals	**$44**	$39	$36
Contingent rentals	**6**	5	6
	50	44	42
Less: Rental income from sub-leased properties	**31**	30	30
Net rental expense	**$19**	$14	$12

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.

10. 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 total consolidated assets of the Corporation and its subsidiaries.

11. Taxes, Other Than Income Taxes

Years ended December 31	1984	1983	1982
Federal sales tax	**$137**	$138	$139
Mineral tax	**10**	14	13
Property tax	**17**	17	15
Other	**11**	10	17
Total	**$175**	$179	$184

In addition, federal excise tax and provincial motor fuel and oil taxes paid or due to taxing authorities for the years ended December 31, 1984, 1983 and 1982 in the amounts of $437, $464, and $439, respectively, have not been included in the income statement.

12. Income Taxes

The provision for current income taxes includes Incremental Oil Revenue Tax (IORT) for the period January 1, 1982 to May 31, 1982 amounting to $20. In the Corporation's opinion, this tax is considered to be a component of income tax. For the period June 1, 1982 to May 31, 1985, IORT has been suspended and all income during this period is subject to federal and provincial income taxes.

The provision for deferred income taxes relates to:

Years ended December 31	1984	1983	1982
Intangible drilling costs	**$ 3**	$ 7	$ –
Depreciation	**(9)**	(9)	1
Inventories	**3**	16	(4)
Other	**4**	(6)	1
Total	**$ 1**	$ 8	$ (2)

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

Years ended December 31	1984		1983		1982	
	Amount	**%**	Amount	%	Amount	%
Income taxes at statutory rates	**$445**	**47**	$377	48	$321	48
Petroleum and gas revenue tax	**86**	**9**	81	10	65	10
Resource allowance	**(174)**	**(18)**	(170)	(22)	(135)	(20)
Disallowed royalties	**188**	**20**	183	23	165	25
Provincial tax credits and rebates	**(13)**	**(2)**	(17)	(2)	(14)	(2)
Other	**(6)**	**(1)**	(8)	(1)	(13)	(2)
Income taxes and their effective rates as reflected in the consolidated statement of income	**$526**	**55**	$446	56	$389	59

Millions of Canadian dollars except per share data

13. Segmented Financial Data

Business Segments	Energy Resources			Petroleum Products			Consolidated		
Years ended December 31	**1984**	1983	1982	**1984**	1983	1982	**1984**	1983	1982
Sales and services									
Outside	**$1,016**	$ 860	$ 602	**$5,140**	$4,792	$4,166	**$6,156**	$5,652	$4,768
Intersegment	**382**	446	421	**2**	1	1	**–**	–	–
	1,398	1,306	1,023	**5,142**	4,793	4,167	**6,156**	5,652	4,768
Income (loss) after income taxes									
Operating income (loss) before write-offs	**373**	347	234	**18**	(46)	31	**391**	301	265
Write-off of manufacturing, terminal and marine assets	**–**	–	–	**(21)**	(15)	(22)	**(21)**	(15)	(22)
Operating income (loss)	**373**	347	234	**(3)**	(61)	9	**370**	286	243
Non-operating income, unallocated corporate expenses and consolidation adjustments							**53**	58	32
Net Income							**423**	344	275
Identifiable Assets									
Segment assets	**896**	1,079	985	**1,770**	1,865	1,815	**2,666**	2,944	2,800
Corporate assets and consolidation adjustments							**743**	344	166
Total assets							**3,409**	3,288	2,966
Depreciation, depletion, and amortization	**44**	44	34	**41**	39	38	**85**	83	72
Capital and exploration expenditures	**$ 161**	$ 128	$ 134	**$ 84**	$ 59	$ 63	**$ 245**	$ 187	$ 197

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.

14. Pension Plan

The total expense for the employee pension plan amounted to $8 in 1984, $10 in 1983 and $9 in 1982. The present value of the unfunded liability of $10 in respect of prior service at December 31, 1983 has been provided in 1984 through the application of a portion of the plan's surplus determined by an actuarial valuation of the pension plan.

Accumulated plan benefits and plan net assets were:

January 1	1984
Actuarial present value of accumulated plan benefits:	
Vested	$120
Nonvested	16
Total	$136
Net assets available for benefits at fair market value	$203
Weighted average assumed rate of return used in determining the actuarial present value of plan benefits	7%

15. Subsequent Event

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 inter-company promissory note of Canadian Reserve Oil and Gas Ltd., ("Canadian Reserve") representing the net book value of Canadian Reserve at that date which approximates fair market value. An independent valuation was obtained as to the fair market value of the outstanding shares of Canadian Reserve. Canadian Reserve, which had been previously acquired by Texaco Inc. in 1984, is an exploration and producing company active primarily in western Canada.

In conjunction with Foreign Investment Review Act approval obtained in respect of the acquisition of Canadian Reserve, the Corporation has undertaken to make capital and exploration expenditures of $800 (inclusive of the acquisition cost of Canadian Reserve) in 1985, and $300 in each of the years 1986 through 1988 inclusive. Subject to meeting certain conditions, this period may be extended beyond 1988.

The following summarizes the net assets acquired:

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

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, 1984 and 1983, and the related consolidated statements of income, retained earnings and changes in financial position for each of the three years in the period ended December 31, 1984. 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, 1984 and 1983, and the results of their operations and changes in their financial position for each of the three years in the period ended December 31, 1984, in accordance with generally accepted accounting principles applied on a consistent basis.

Arthur Andersen & Co.

Toronto, Ontario
February 6, 1985

Millions of Canadian dollars except where noted

The information set out in this section is prepared in accordance with the United States Financial Accounting Standards Board Statement No. 69 (FASB 69). This Statement amends the disclosure requirements of FASB Statements 19 and 25. The Securities and Exchange Commission has also adopted these disclosures.

Capitalized Costs

December 31	**1984**	1983
Proved properties	**$800**	$707
Unproved properties	**110**	88
Support equipment and facilities	**12**	14
Gross capitalized costs	**922**	809
Less: Accumulated depreciation, depletion, and amortization	**315**	276
Net capitalized costs	**$607**	$533

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	**1984**	1983	1982
Acquisition of unproved properties	**$ 25**	$ 17	$ 7
Exploration costs	**56**	60	54
Development costs	**81**	46	64
Total costs incurred	**$162**	$123	$125

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.

Results of Operations from Producing Activities

Years ended December 31	1984	1983	1982
Revenues			
Sales to unaffiliated entities	**$ 948**	$ 804	$542
Transfers within Texaco Canada and sales to unconsolidated affiliates	**341**	401	388
Total	**1,289**	1,205	930
Production costs			
Petroleum and gas revenue tax	**182**	169	135
Other production costs	**148**	122	102
Total	**330**	291	237
Exploration and development expenses	**41**	49	55
Depreciation, depletion, and amortization	**42**	43	32
Results of operations from producing activities before estimated income tax	**876**	822	606
Estimated income tax	**505**	476	373
Results of operations from producing activities (excluding corporate overhead and interest costs)	**$ 371**	$ 346	$233

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 cost of purchased oil and gas, including royalties, and the revenues from the sale thereof 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	1984	1983	1982
	Canadian dollars per cubic metre		
Average sales prices			
Crude oil	**$214.56**	$205.56	$162.79
Natural gas liquids	**171.73**	157.38	121.17
Natural gas	**.11**	.10	.10
Average production costs	**48.91**	43.72	36.61

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.

Millions of Canadian dollars except where noted

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, 1981	36.5	9.3	44.3
Increase (decrease) during 1982 attributable to:			
Revisions of previous estimates	3.5	0.3	0.8
Extensions, discoveries and other additions	0.2	1.0	0.5
Production	(4.8)	(0.7)	(0.9)
*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**
*Includes net proved developed reserves of Texaco Canada Inc. and subsidiary companies:			
As at December 31, 1981	36.5	9.2	41.1
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**

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 and 1981, net reserves have been computed giving consideration to known price increases in old oil resulting from pricing agreements between the governments of Canada and the producing provinces. 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 and 1981. The effect of this change is reflected in the revisions of previous estimates in 1981. Net reserves as at December 31, 1984 and 1983 have been determined using prices and the royalty structure in effect at these dates.

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

December 31	1984	1983	1982
Future cash inflows	$13,002	$12,387	$12,855
Future development and production costs	3,888	3,758	3,695
Future income tax expenses	5,139	4,910	5,422
Future net cash flows	3,975	3,719	3,738
10% Annual discount for estimated timing of cash flows	2,057	1,802	1,728
Standardized measure of discounted future net cash flows	$ 1,918	$ 1,917	$ 2,010

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

Years ended December 31	1984	1983	1982
Standardized measure at beginning of year	$1,917	$2,010	$1,589
Increases (decreases):			
Sales and transfers of oil and gas produced, net of production costs	(955)	(914)	(693)
Net changes in prices and production costs	568	(212)	142
Changes in estimated future development costs	(108)	(5)	(61)
Extensions, discoveries, other additions and improved recovery, less related costs	316	472	121
Development costs incurred during the year	76	41	57
Revisions of previous quantity estimates	(415)	(376)	629
Accretion of discount	467	517	449
Net change in income taxes	52	384	(223)
Standardized measure at end of year	$1,918	$1,917	$2,010

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.

As at December 31, 1982 the future cash inflows were based on prices and royalties in effect at year-end except for old oil. The prices and royalties for old oil have been increased in accordance with the pricing agreements between the governments of Canada and the producing provinces, but the prices have been limited to 75 per cent of current world price. As at December 31, 1984 and 1983 future cash inflows were computed using year-end prices. The future costs were computed using year-end costs, and year-end statutory tax rates, adjusted for permanent differences, that relate to existing proved oil and gas reserves in which the Corporation has mineral interests.

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. The adjusted amount was computed under a compound interest method which resulted in an effective rate of approximately 10.5 per cent.

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. The CICA has also recommended the disclosure of information relating to quantities of reserves of crude oil and natural gas as well as certain exploration costs. This information is disclosed as part of "Oil and Gas Producing Activities" on pages 36 to 39.

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

	As reported in the Historical Cost Statements		Current Cost Basis
Years ended December 31	1984	1984	1983*
Revenues	$6,267	$6,267	$5,975
Deductions			
Cost of sales and operating expenses	4,590	4,608	4,419
Depreciation, depletion, and amortization	85	186	202
Other expenses	643	643	671
	5,318	5,437	5,292
Income before Income Taxes	949	830	683
Income Taxes			
—current	525	525	457
—deferred	1	1	8
	526	526	465
Net Income	$ 423	$ 304	$ 218

Consolidated Balance Sheet Items

December 31	1984	1984	1983*
Inventories	$ 501	$ 503	$ 588
Net properties, plant, and equipment	1,372	2,505	2,663
Net assets (common shareholders' equity)	2,089	3,224	3,207

Other Supplementary Information

Years ended December 31	Current Cost Basis 1984	1983*
Increase in the current cost of inventories and properties, plant, and equipment held during the year was attributed to:		
Effect of general inflation	$112	$140
Increase (decrease) in specific prices	(75)	48
Total increase in the current cost of inventories and properties, plant, and equipment	$ 37	$188
Loss in general purchasing power from having net monetary assets	$ 17	$ 10

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

Current Cost Estimates
In accordance with CICA requirements, only cost of goods sold included in the caption "Cost of sales 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 residual 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 55 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 63 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 1984 entirely accounted 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			
1984				
March 31	**$1,656**	**$240**	**$119**	**$0.96**
June 30	**1,463**	**187**	**90**	**0.72**
September 30	**1,432**	**211**	**104**	**0.83**
December 31	**1,605**	**209**	**110**	**0.90**
1983				
March 31	1,268	157	76	0.61
June 30	1,344	160	75	0.59
September 30	1,473	231	107	0.86
December 31	1,567	177	86	0.68
1982				
March 31	1,225	145	66	0.51
June 30	1,078	134	72	0.56
September 30	1,164	170	71	0.56
December 31	1,301	150	66	0.52

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.

Canadian Ownership Rate (COR)
A measurement of the degree to which a petroleum company is owned by Canadians. This rate is certified by the Government of Canada as the basis for awarding cash grants under the Petroleum Incentives Program.

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.

Conventional Old Oil Price (COOP)/ Old Oil
Currently any oil to which NORP pricing does not apply. In principle, old oil prices cannot exceed 75% of the world prices.

Current ratio
Current assets divided by current liabilities.

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.

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

Loss of control
The uncontrolled movement of oil, gas or water up the well bore in a well being drilled or serviced. Also includes circumstances in which the control valving of an operating well becomes ineffective.

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 interest of others.

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

New Oil Reference Price (NORP)
NORP is the government-set price applied to all conventional oil from pools discovered since 1973, oil recovered by an enhanced recovery technique, production from infill wells meeting specific requirements, synthetic crude oil and crude oil from Canada Lands. NORP is generally comparable to world prices.

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.

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.

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

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 the 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.

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, and 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.

Metric 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

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

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