ANNUAL REPORT 1983

North Canadian Oils Limited

COMPANY PROFILE

North Canadian Oils Limited is a Canadian company founded in 1947 with its principal office in Calgary, Alberta. The Company is engaged in the exploration for hydrocarbons, the development and production of these resources and the transmission of natural gas. Producing properties and prospective exploration lands are located in western Canada and in various areas in the United States.

The shares of the Company have been listed on the Toronto and American Stock Exchanges since 1952.

ANNUAL MEETING

The 1984 Annual Meeting of shareholders will be held Thursday, May 24, 1984, at 9:00 a.m. local time, the Westin Hotel, 320 - 4th Avenue S.W., Calgary, Alberta, Canada.

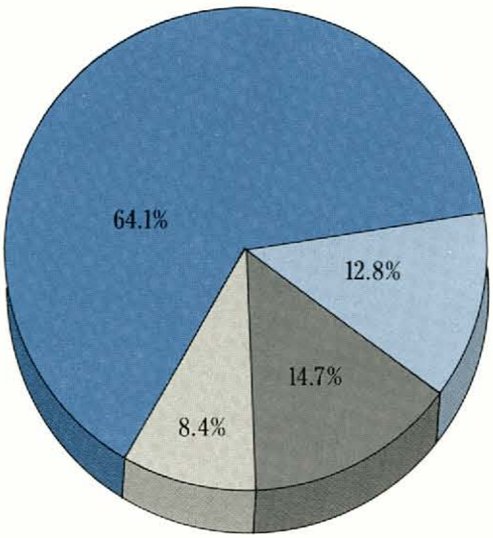
THE YEAR AT A GLANCE

Financial	1983	1982
Gross Revenue (before royalty)	$ 51,397,000	$35,119,000
Funds Provided from Operations	23,103,000	17,328,000
Net Income	16,577,000	11,894,000
Exploration Expenditures	5,599,000	2,443,000
Development Expenditures	9,652,000	6,873,000
Investments	135,946,000	67,075,000
Shareholders' Equity	102,172,000	66,251,000
Income per Common Share—Fully Diluted	2.35	2.07

Operating		
Natural Gas Production—billion cubic feet	17.5	17.0
Average per day—million cubic feet	48.0	46.6
Pipeline—		
Annual throughput, billion cubic feet	9.2	9.1
Oil and Natural Gas Liquids (NGL)—barrels	152,000	74,000

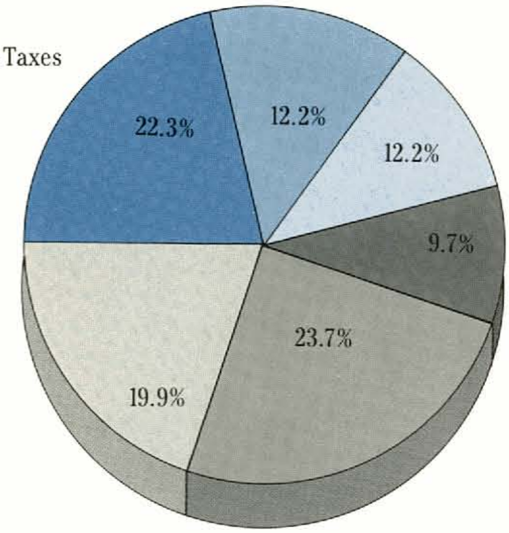
REVENUE

- Natural Gas
- Pipeline
- Dividend & Other
- Crude Oil



EXPENDITURES

- Government Royalties & Direct Taxes
- Administration & Operations
- Exploration
- Gas Purchased For Resale
- Development
- Debt Retirement & Interest



Proved and Probable Reserves (Gross)
December 31, 1983
NATURAL GAS .... 600 Billion cubic feet
CRUDE OIL & NGL ... 1,897 Thousand barrels

TO THE SHAREHOLDERS

The year was highlighted by continued improvement in financial results from Company operations and the successful issue of $61.5 million of convertible debentures and preferred shares. It is gratifying to report these accomplishments particularly during a period of severe recession in Canada and reduced demand for oil and natural gas.

Several factors contributed to this record performance, notably: increased production of both oil and natural gas from operations in Canada and the United States; higher average oil and gas prices; improved returns from pipeline operations; and increased investment income.

FINANCIAL

Net earnings were $16.6 million compared to $11.9 million in 1982. Fully diluted earnings per common share were $2.35 up from $2.07 earned the previous year. Funds generated from operations increased to $23.1 million compared with $17.3 million recorded in 1982, a gain of 34 percent. Return on average capital employed and shareholders equity improved over 1982 and were 18.5 percent and 18.0 percent respectively.

OPERATIONS

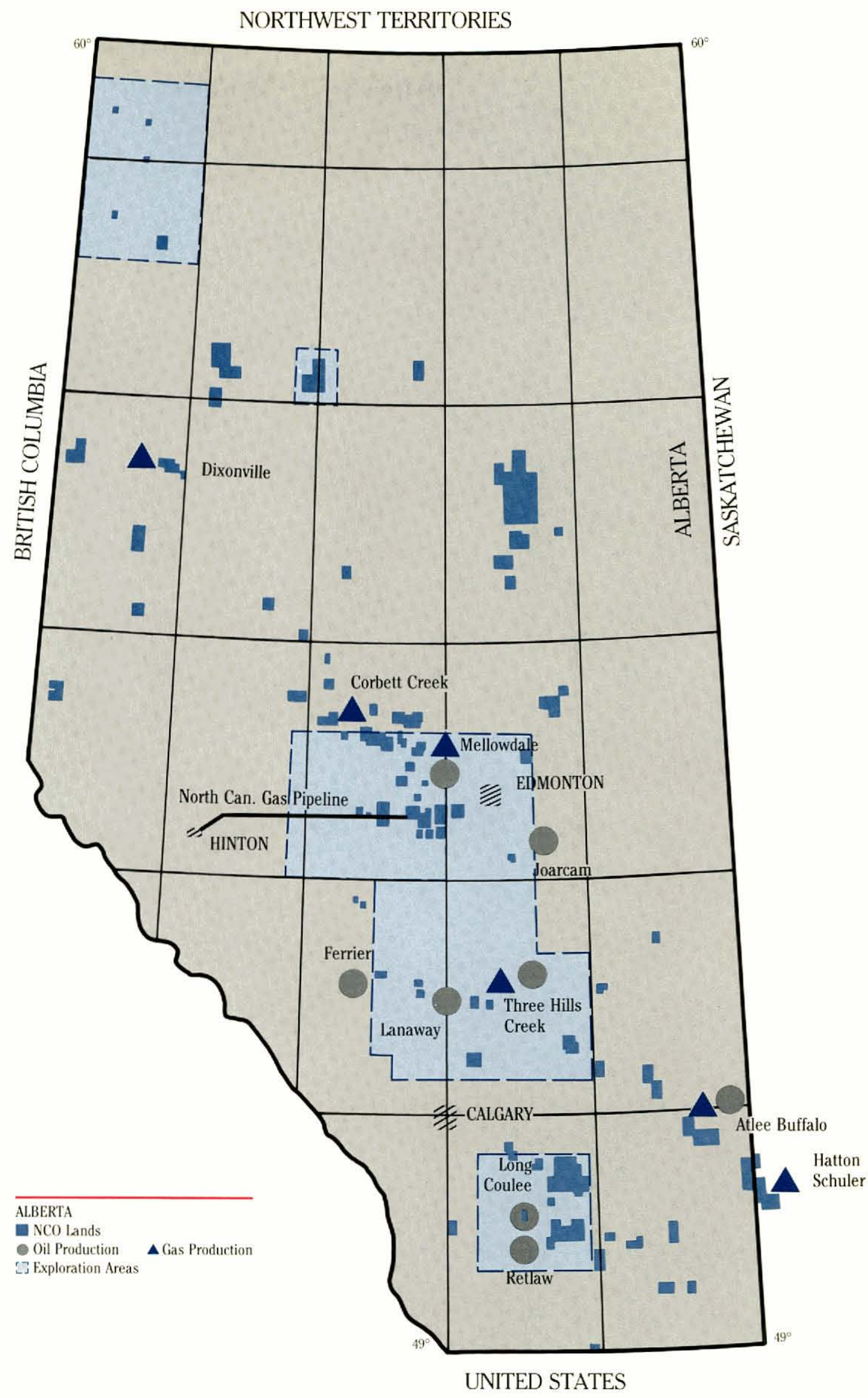
In recognition of improved economics for new oil, exploration activities focused on oil prospects in Alberta and Saskatchewan. Thirty-one exploratory wells were drilled resulting in seven oil and six gas discoveries. In addition, 158 infill development wells were successfully completed in the Company's major gas fields. In the United States, the results of the first of a ten well drilling commitment on a farm-out of 140,000 acres is currently being evaluated. The Company has a one-third interest in this highly prospective oil play in Colorado.

In 1983 crude oil and natural gas liquids production from Canada and the United States averaged 416 barrels per day, double the 1982 production level. The Company's average daily natural gas production was approximately 48 million cubic feet, marginally higher than last year but significant in light of the reduced demand for both domestic and export natural gas this year. Throughput of the Wabamun Hinton Pipeline totalled 9.2 billion cubic feet for the year.

OUTLOOK

During the period of lower demand and softer prices for hydrocarbons, the Company significantly improved financial gains by maximizing the return from established producing areas, and by participating in a broad spectrum of exploration plays. North Canadian has successfully weathered the downturn in the petroleum industry and emerged in a growth position. The long-term outlook for the petroleum industry beyond 1985 is encouraging as it is evident that non-renewable hydrocarbon resources will continue to be in demand. With improved cash flow and capital resources, the Company is well positioned to increase the search for new crude oil and natural gas reserves.

James F. Kay
Chairman of the Board
April 20, 1984

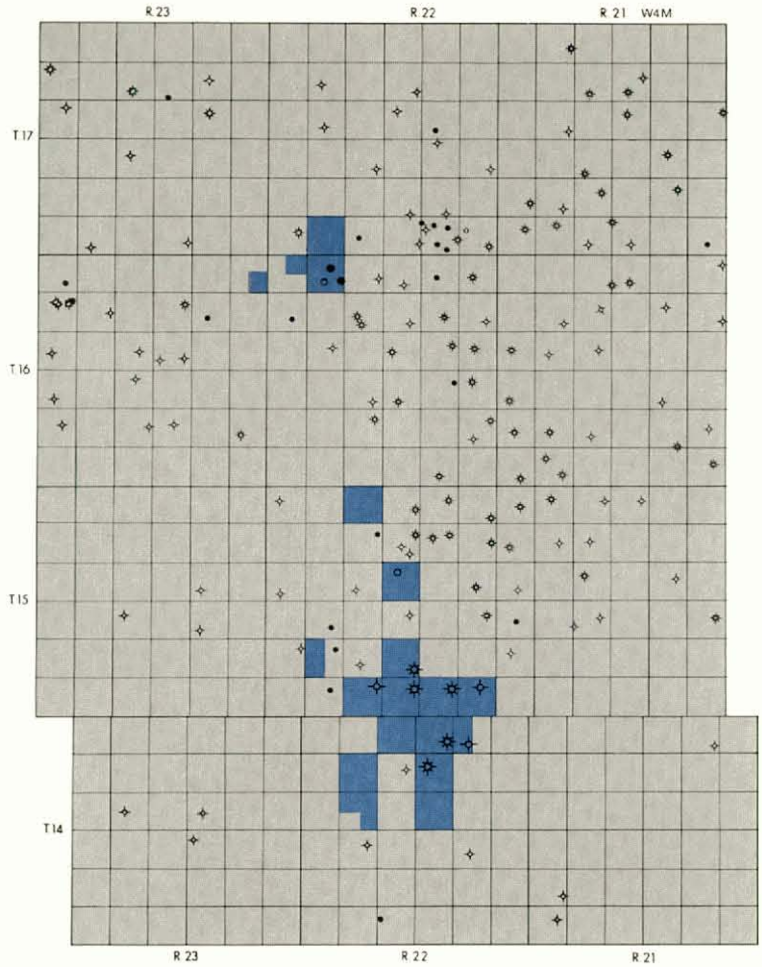


NORTHWEST TERRITORIES
60°
60°
BRITISH COLUMBIA
ALBERTA
SASKATCHEWAN
Dixonville
Corbett Creek
Mellowdale
EDMONTON
North Can. Gas Pipeline
HINTON
Joarcam
Ferrier
Lanaway
Three Hills
Creek
CALGARY
Atlee Buffalo
Hatton
Schuler
Long
Coulee
Retlaw
49°
49°
UNITED STATES
ALBERTA
NCO Lands
Oil Production
Gas Production
Exploration Areas

EXPLORATION

Exploration activity reached a high level in 1983 by broadening exposure to new prospects, mainly in western Canada. Seven exploration programs were successfully conducted, three in Alberta, three in Saskatchewan and one in Colorado. During the year, the Company participated directly in the drilling of 31 exploratory wells which resulted in 7 new oil discoveries and 6 new gas discoveries. Also, extensive geophysical evaluation and land acquisitions were carried out in a number of highly prospective areas.

North Canadian participated in the discovery of a large Cretaceous gas pool at Long Coulee which is estimated to contain 40 billion cubic feet of recoverable gas. Late in 1983, oil was also discovered in a separate Cretaceous pool. The first follow up well was completed for production testing in January, 1984. Twenty-four hundred acres of new land rights were acquired in this prospective area with the Company's interest ranging from 20 to 100 percent.



LONG COULEE AREA, ALBERTA
- NCO Lands
- Oil Well
- Gas Well
- Dry and Abandoned Well
- Well Location

The Company with partners evaluated the Devonian reef complex of south central Alberta. Recent advances in geophysical interpretation have assisted in defining new potential oil bearing reefs in this long-standing and prolific producing area. Extensive seismic evaluation and land acquisition commenced at mid-year and are actively being pursued as new prospects for drilling are defined.

UNDEVELOPED ACREAGE
DECEMBER 31, 1983

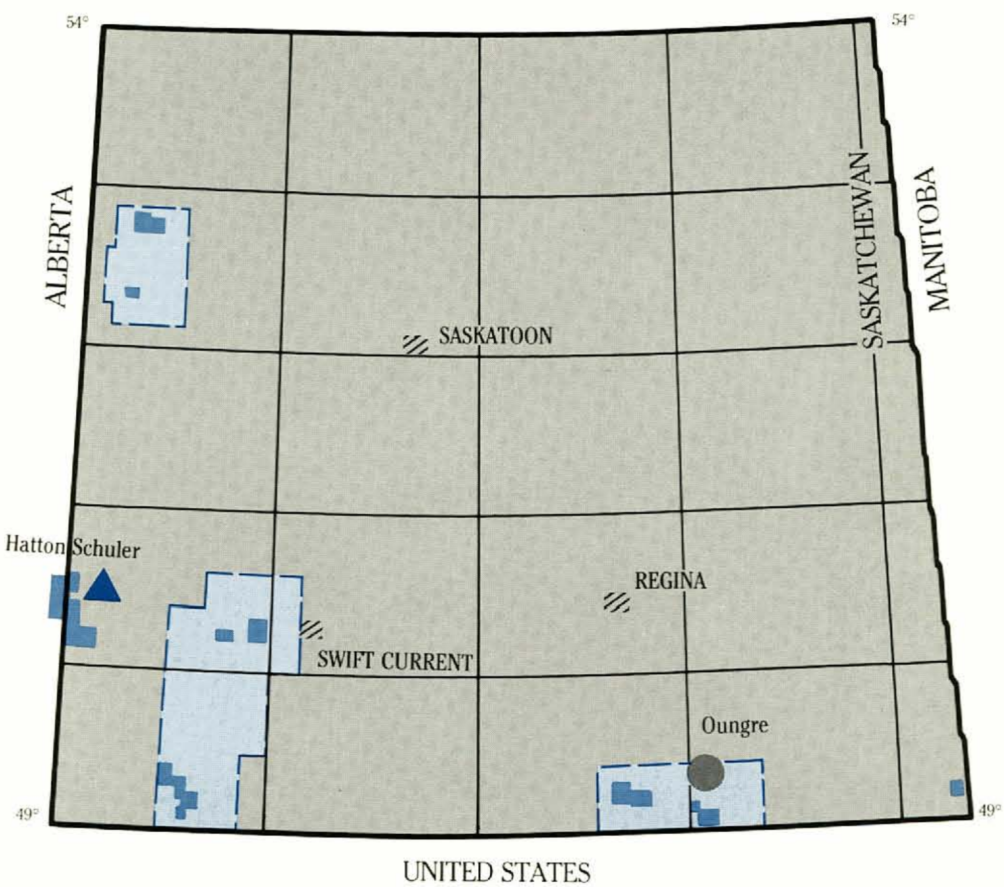
Area	Gross	Net
Alberta	635,219	123,912
Saskatchewan	65,161	29,514
United States	1,035,073	276,932
	1,735,453	430,358

A geophysical evaluation of the prolific oil producing Devonian Keg River reef basins of northwestern Alberta was launched in late 1983 following new oil discoveries and renewed activity in the area. Based on initial interpretation of 1000 miles of geophysical data, an interest in four tracts of land was acquired. Interpretation of new seismic data along with additional land acquisition will precede exploratory drilling during the coming winter.

North Canadian participated in exploring several prospects along the Jurassic oil producing belt in southwestern Saskatchewan. Based on 1,170 miles of seismic interpretation, a 25 percent interest in 13,595 acres of mineral leases was acquired. Four wildcat wells were drilled, one of which has been cased for production testing. A further six to ten wells are planned for drilling in 1984.

An active exploration program of geophysics, land acquisition and drilling resulted in two oil discoveries in southeastern Saskatchewan during 1983. A further well was drilling at year-end, and the Company will continue to aggressively expand its interests in this attractive play.

The Company's search for high reserve oil pools in the Coleville-Lloydminster heavy oil belt of west central Saskatchewan led to the drilling of two exploratory oil discoveries in which North Canadian's interest averages 40 percent.



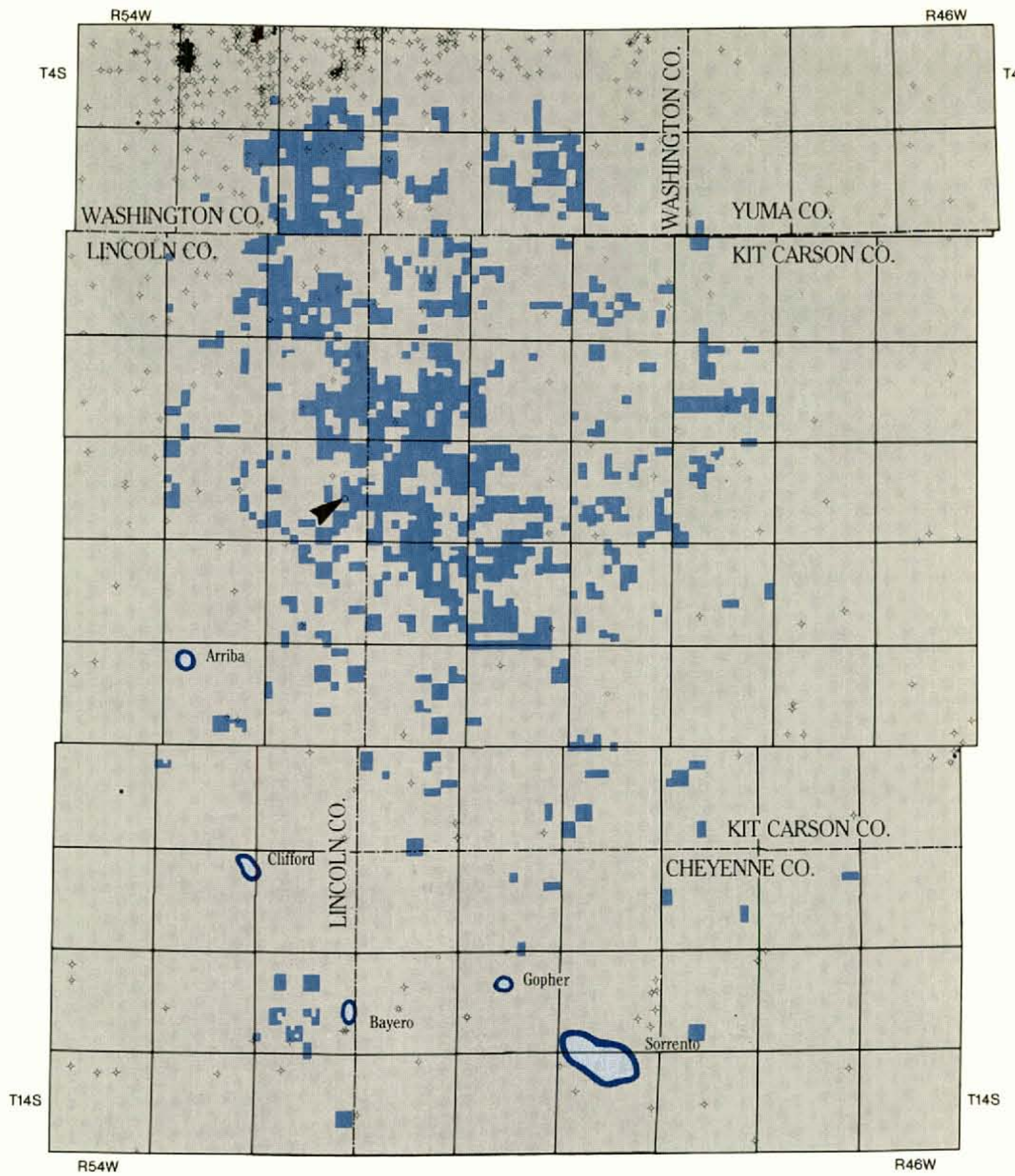
SOUTHERN SASKATCHEWAN
■ NCO Lands
● Oil Production ▲ Gas Production
⬚ Exploration Areas

In the United States, North Canadian farmed out to a major exploration company its one-third interest in a 140,000 acre block of land located in southeastern Colorado. The operator drilled a basement test as the first of a ten well commitment following seismic evaluation of this new oil area. The well was cased and several zones were being evaluated at year end.

DEVELOPMENT

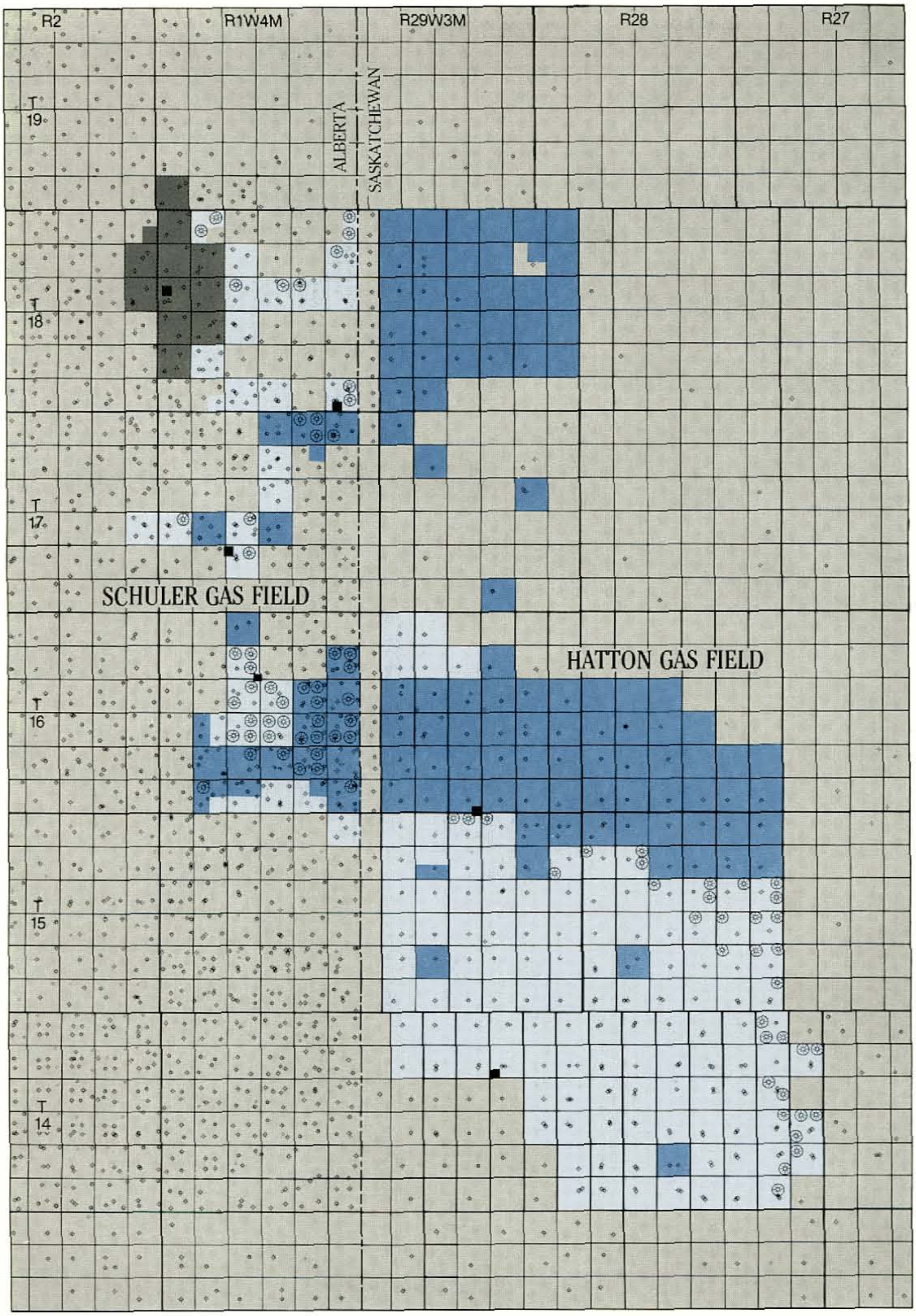
Development drilling in 1983 was concentrated in the Company's wholly owned major natural gas producing properties in Alberta and Saskatchewan. Production capability from both the Hilda Schuler and Atlee Buffalo fields located in southeastern Alberta was improved by the drilling of 123 wells which were completed in the Medicine Hat or Milk River zones. The addition of the new wells will sustain the level of deliveries to TransCanada PipeLines Limited under contracts which are not subject to curtailment due to restricted market requirements.

In Saskatchewan the Company commenced a two year drilling program to increase deliveries to Saskatchewan Power Corporation with the completion of 35 dual zone Medicine Hat and Milk River wells. Under this program the volume of natural gas to be produced will be restored to the original contract level of approximately 12 billion cubic feet annually.



SOUTHEAST COLORADO AREA
- NCO Lands
- Oil Well
- Gas Well
- Dry and Abandoned Well
- Oil Pool Outlines
- Cased Well

Early in 1984 the government of Saskatchewan introduced a new gas policy which could have a significant favorable long-term impact on the Company's natural gas holdings in that province. The new policy provides for the volume of natural gas deliveries from Saskatchewan fields to increase over 5 years in annual increments of 7 billion cubic feet from 35 billion cubic feet to 70 billion cubic feet per year. It is anticipated that a share of this new volume will be allocated by the gas purchaser, Saskatchewan Power Corporation, to the Company's 213 sections of gas leases located in the Hatton area.



HATTON SCHULER AREA
NCO LANDS
Medicine Hat Rights
Milk River Rights
Medicine Hat Rights and Milk River Rights
Compressor Station
1983 Development Wells

PRODUCTION

Production of natural gas, crude oil and gas liquids for the current year surpassed the volumes produced in 1982. Average daily production of natural gas was 48.0 million cubic feet, up from 46.6 million cubic feet in 1982. Crude oil and natural gas liquids averaged 416 barrels per day compared to 202 barrels per day produced in 1982.

Deliveries to TransCanada PipeLines Limited from the Company's major Alberta gas fields at Hilda Schuler and Atlee Buffalo averaged approximately 18.5 million cubic feet per day, up 10 percent over the preceding year. Natural gas production from the Hatton field in Saskatchewan averaged 28.2 million cubic feet per day during the first eleven months of the year. Since that time production levels have been sustained at greater than 36 million cubic feet per day as a result of the new wells which came on stream in December 1983.

In 1983, production of crude oil and natural gas liquids totalled 152,000 barrels, an increase of 105 percent over 1982. Canadian production increased 71 percent to an average of 360 barrels per day of which 312 barrels is from the Company's 10 percent working interest in Joarcam Viking Unit #2.

In the United States, production more than doubled to 20,386 barrels. The increase of 141 percent is primarily from the Company's interest in the Curtis Creek field in Arkansas.

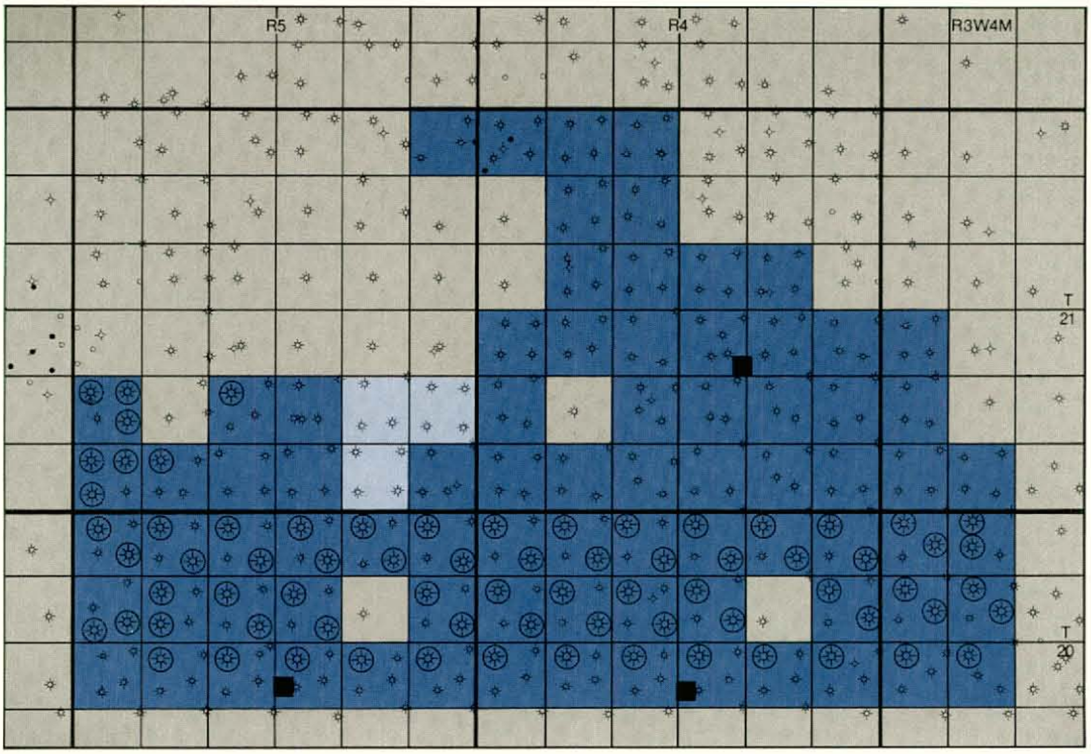
Production revenue for the year after royalty was up $10.7 million or 48 percent. The increase is attributable to higher production of both oil and gas and improved product prices. Higher netbacks for Saskatchewan gas and increased prices for crude oil more than offset reduced Alberta gas prices.

PIPELINE

Net operating revenue from the Company's 136 mile Wabamun to Hinton gas pipeline and from the sale of discount gas was up 44 percent over 1982. Sales to industrial customers and distributors, combined with fees on gas transported for utility companies, generated $2.1 million or about 6 percent of North Canadian's net operating revenue. The total throughput of the pipeline was 9.2 billion cubic feet, approximately the same as 1982.

Natural gas is purchased at a discount under several short-term contracts with producers, and sold under various terms to pipeline customers. North Canadian has maintained its long-term gas purchase contract with Alberta and Southern Gas Co. Ltd. to ensure a supply of natural gas for these customers. This contract protects supply to a maximum of 30 million cubic feet per day. Gas supplied to some customers under long-term contracts is fixed at the sum of the purchase price plus a surcharge for transportation.

During the year the Company constructed a six mile lateral line to move gas from the Hinton gas field to the Wabamun Hinton pipeline. Also North Canadian contracted to supply natural gas to a thermal coal project now under construction, and a new building material plant located at Edson, Alberta.



ATLEE BUFFALO AREA
NCO LANDS
100% Interest
50% Interest
Compressor Stations
1983 Development Wells

PROVEN AND PROBABLE RESERVES (Gross)
at December 31, 1983

	Proved Developed			
	Producing	Non-Producing	Probable	Total
Natural Gas				
(Billion Cubic Feet)				
Canada	542	37	21	600
Crude Oil & Natural Gas Liquids				
(Barrels—000's)				
Canada	1247	108	448	1803
U.S.A.	94	—	—	94
	1341	108	448	1897

CLASSIFICATION
PROVED RESERVES are those established by existing production, by adequate tests and by other information on cased zones in existing wells, or those existing beneath undeveloped tracts offsetting, or between, producing wells where geological control confirms the presence of these reserves.

PROBABLE RESERVES are those estimated for locations or areas beyond proved control, where geological and seismic data reasonably confirm satisfactory structural and formation characteristics; for those in cased zones in existing wells where data reasonably confirm the presence of these reserves, but where such data are inadequate to establish proof of the productivity of the reserves.

FINANCIAL REVIEW

RESULTS OF OPERATIONS

Comparison of 1983 to 1982

REVENUE

Natural gas and crude oil revenue net of royalties was $32.6 million, an increase of $10.7 million or 48 percent over fiscal 1982.

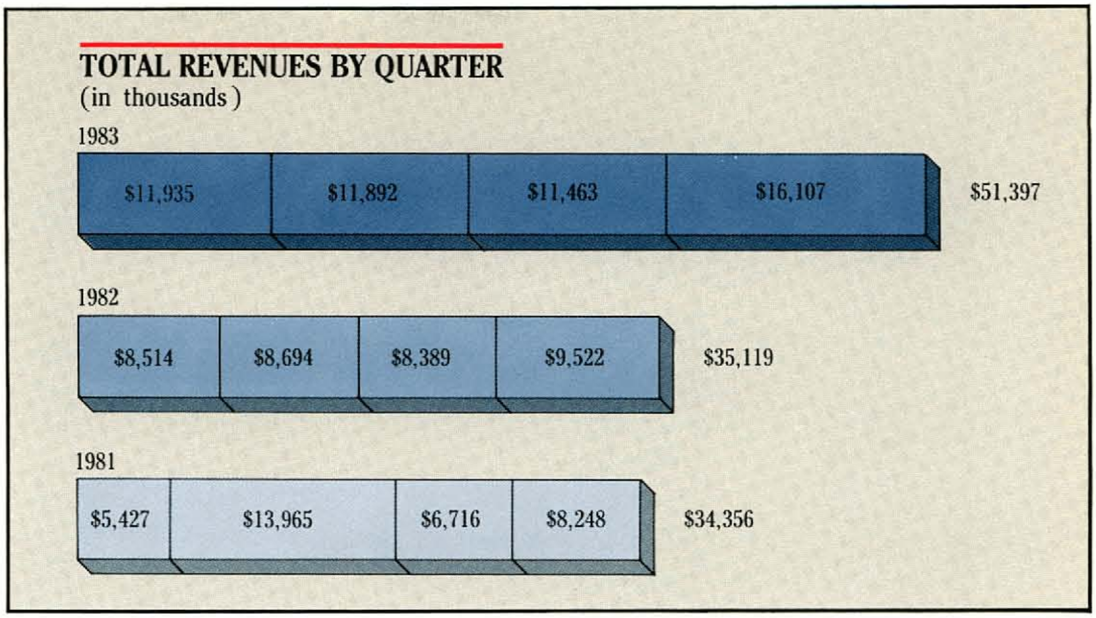
An increase of $8.5 million in natural gas revenue is directly attributable to increased production in Alberta and Saskatchewan at a higher average price than in 1982. Crude oil and condensate production more than doubled in 1983 compared to last year which, combined with increased prices, resulted in a $2.2 million gain.

Revenue from pipeline throughput and sales, net of the cost of gas, was $2.1 million, a 44 percent increase over 1982. The improvement is related to additional volumes, improved tariffs and the marketing of gas to new customers.

Investment and other income was up by $3.9 million as a result of an increase in short-term investments.

EXPENSES

Operating expenses of $4.7 million, up slightly over 1982, reflect the increase in the number of producing wells and higher plant and equipment maintenance costs. The change in interest expense reflects the increase in long-term debt outstanding during the period.



The 1983 provision for depreciation and depletion increased due to a greater net book value of resource property assets. Income and resource taxes for the year represented 33 percent of pre-tax income compared to 32 percent in 1982. The increase is in direct relation to higher resource and pipeline income.

NET INCOME

Net income was $16.6 million compared to $11.9 million in 1982. Fully diluted earnings per common share were $2.35 up from $2.07 earned the previous year.

Comparison of 1982 to 1981

REVENUE

Revenue from crude oil and natural gas operations, net of royalties was $21.9 million in the 1982 fiscal year compared to $15.2 million in the 1981 fiscal year. The increase is primarily related to the improved price and production of natural gas from the Company's Alberta gas fields and from higher crude oil production in Canada and the United States. A 25 percent improvement in net pipeline revenue took place in 1982 due to increases in pipeline throughput and marketing fees. Investment income, net of interest expense, at $1.8 million increased substantially over the 1981 figure.

EXPENSES

The costs associated with maintaining production from mature natural gas fields, combined with the increase in the number of producing wells contributed to higher operating expense in 1982. In addition, the Petroleum and Natural Gas Revenue Tax initially levied at 8 percent was increased to 16 percent on January 1, 1982. Depreciation and depletion increased $324,000 over 1981 as a result of an increased asset base. The Company's total tax provision for 1982 is $3.9 million compared to $7.3 million in 1981, a decrease attributable to an asset disposal in 1981.

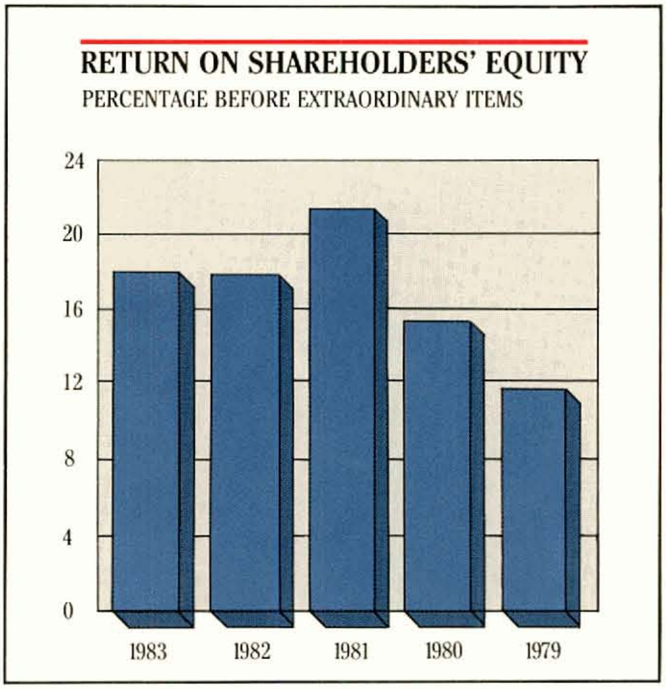
NET INCOME

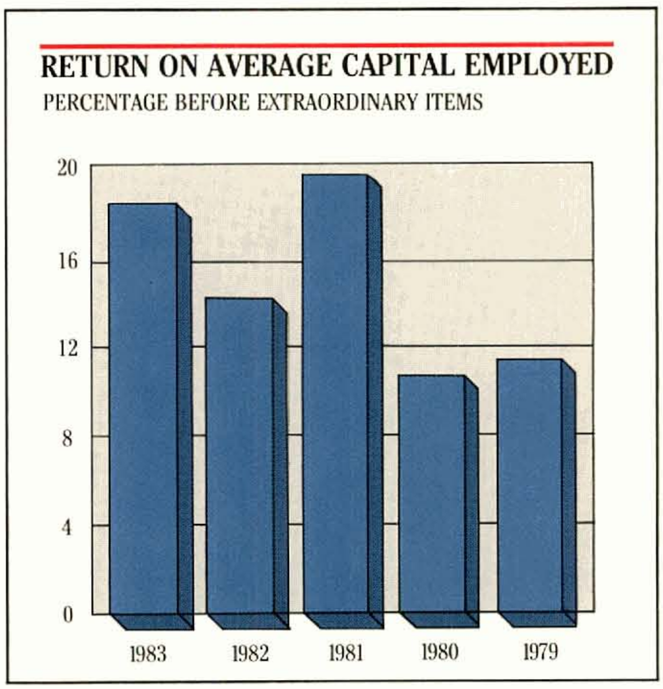
Net income for the year ended December 31, 1982 was $11.9 million or $2.07 per common share compared to $10.7 million or $2.02 per common share in 1981. The 1981 net income after tax included $4.1 million arising from the disposition of the Company's coal properties.

CAPITAL RESOURCES AND LIQUIDITY

During the year, the Company strengthened its financial position through the issue of $21.5 million of floating rate convertible debentures, $20 million of 8 percent convertible debentures and $20 million Class B junior preferred shares. The proceeds of $61.5 million were, at year end, invested in short term investments. This new debt and equity combined with lines of credit of $105 million established with three lending institutions, and against which $41 million was drawn at year end, has substantially improved the capital structure of the Company.

For the past several years, North Canadian's policy has been to finance its resource capital expenditure program through cash flow from operations. In 1983 and 1982, capital expenditures on oil and gas properties were approximately $16 million and $9 million respectively. Based on forecasts which take into consideration, among other things, the economic outlook and government policies directly related to the oil and gas industry, the Company will fund its 1984 capital expenditure program estimated at $25 million and its debt service obligations through internal cash flow. Projections beyond 1984 are positive given the Company's current financial position.





SELECTED FINANCIAL DATA OF THE COMPANY

The following table summarizes certain selected financial data in accordance with Generally Accepted Accounting Principles in Canada and the United States and is qualified in its entirety by the more detailed Consolidated Financial Statements of the Company appearing elsewhere in the report.

	Year ended December 31,				
	1983	1982	1981	1980	1979
	(Stated in thousands of dollars except for per share data)				
Net operating revenues	**$ 46,741**	$ 31,394	$22,786	$17,704	$15,600
Income before extraordinary items	**$ 16,577**	$ 11,894	$ 5,929(a)	$ 5,440(a)	$ 4,002(a)
Income before extraordinary items per common share	**$ 2.35**(c)	$ 2.07	$ 1.12	$ 1.22(b)	$ .89
Total assets (at end of period)	**$226,378**	$140,635	$84,440	$56,156	$69,656
Long-term obligations (at end of period) (d)	**$108,384**	$ 47,852	$ 6,851	$10,814	$17,843

(a) Before equity in operating income (loss) of an affiliate and after tax gain on disposal of coal properties.
(b) Before extraordinary loss of $2.99 per common share. Net loss for the year ended December 31, 1980 was $2.04 per common share.
(c) Basic for 1983 $2.81 per common share.
(d) Includes redeemable preferred shares and for 1983, Class B Junior preferred shares.

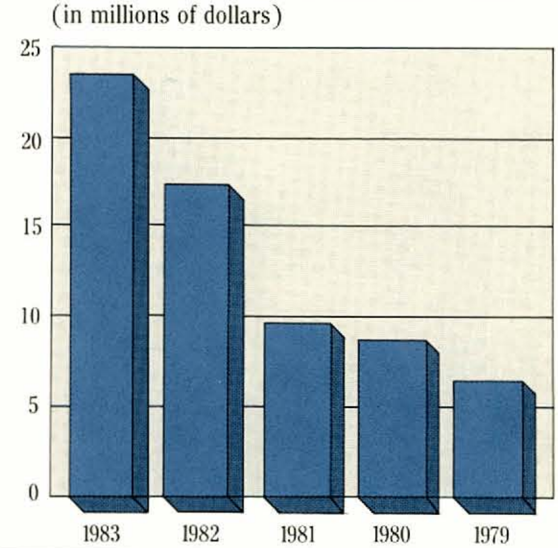
COMMON STOCK PRICE RANGE

	Toronto Stock Exchange (Can.)			
Quarter	1983		1982	
	High	**Low**	High	Low
First	**$18.25**	**$13.00**	$30.50	$10.75
Second	**19.00**	**13.63**	15.00	10.50
Third	**22.25**	**18.50**	16.00	9.50
Fourth	**19.50**	**17.00**	21.00	13.63

	American Stock Exchange (U.S.)			
Quarter	1983		1982	
	High	**Low**	High	Low
First	**$15.00**	**$10.88**	$25.25	$ 9.00
Second	**15.75**	**11.12**	11.25	8.13
Third	**17.75**	**15.00**	13.00	7.63
Fourth	**15.88**	**14.00**	16.50	11.00

FUNDS PROVIDED FROM OPERATIONS

(in millions of dollars)



Five Year Summary of Operations

	1983	1982	1981	1980	1979
	(Stated in thousands of dollars except for per share data)				
Operations					
Revenue					
Gas and Oil	**$ 37,282**	$25,646	$18,788	$12,989	$10,782
Less royalties	**4,656**	3,725	3,560	2,468	1,889
	32,626	21,921	15,228	10,521	8,893
Pipeline operations	**6,577**	5,842	6,076	6,113	5,561
Investment and other income	**7,538**	3,631	1,482	1,070	1,146
	46,741	31,394	22,786	17,704	15,600
Expenses					
Operating and administrative	**6,254**	5,605	3,970	2,554	2,274
Gas purchased for resale	**4,464**	4,374	4,910	4,723	4,408
Interest	**7,940**	1,802	1,523	1,679	2,320
Income tax—current (recovery)	**1,362**	648	1,680	325	(202)
Petroleum and gas revenue tax	**3,618**	1,625	1,228	—	—
	23,638	14,054	13,311	9,281	8,800
Funds Provided From Operations	**23,103**	17,340	9,475	8,423	6,800
Per common share—Fully Diluted	**3.09**	3.03	1.79	1.88	1.46
Depreciation and depletion	**3,232**	2,144	1,820	1,210	962
Gain on sale of coal properties	**—**	—	8,010	—	—
Equity in operating income (loss) of affiliate	**—**	—	1,699	(1,127)	359
Income before undernoted	**19,871**	15,196	17,364	6,086	6,197
Income tax—deferred	**3,294**	3,302	5,635	1,773	1,836
Net income before undernoted	**16,577**	11,894	11,729	4,313	4,361
Extraordinary items	**—**	—	(982)	(13,385)	6,066
Net income (loss)	**$ 16,577**	$11,894	$10,747	$ (9,072)	$10,427
Per common share—Fully Diluted★	**$ 2.35**	2.07	2.02	(2.04)	2.32
Assets					
Investments	**$135,946**	67,075	17,600	8,819	27,430
Property and equipment—net	**$ 78,147**	$64,891	$57,756	$42,019	$33,256
Capital Structure					
Long-Term debt	**$ 87,553**	$46,823	$ 5,769	$ 9,600	$16,547
Deferred taxes	**25,061**	21,767	18,465	12,830	11,057
Shareholders' equity	**$102,172**	$66,251	$54,422	$28,510	$37,506
Capital expenditures					
Exploration	**$ 5,599**	$ 2,443	$ 4,769	$ 5,995	$ 2,800
Development	**$ 9,652**	$ 6,873	$ 8,791	$ 5,311	$ 5,100
Shares outstanding—thousands					
Common—no par value	**5,723**	5,723	5,304	*4,477	*4,453
Class B Junior Preferred Series 1	**1,000**	—	—	—	—
Preferred—par value $50 per share	**17**	21	22	24	26

★Basic $2.81

* Excludes shares owned by affiliate.

	1983	1982	1981	1980	1979
Production and Sales					
Natural Gas Production—billion cubic feet	**17.5**	17.0	*17.0	*18.0	*18.1
Average per day—million cubic feet	**48.0**	46.6	46.6	49.3	49.6
Pipeline—					
Annual throughput, billion cubic feet	**9.2**	9.1	7.2	8.5	9.2
Crude oil and natural gas liquids	**152,000**	74,000	50,000	50,000	47,700

* Includes production of affiliate.

CONSOLIDATED BALANCE SHEET

	December 31 (in thousands) 1983	1982
ASSETS		
CURRENT ASSETS		
Cash	**$ –**	$ 95
Investments (Note 2)	**135,946**	—
Accounts receivable	**11,074**	7,268
Prepaid expenses	**59**	33
	147,079	7,396
LONG-TERM INVESTMENTS (Note 2)	**–**	67,075
PROPERTY, PLANT AND EQUIPMENT ("Full cost" Note 3)	**78,147**	64,891
OTHER ASSETS, at cost	**1,152**	1,273
	$226,378	$140,635
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	**$ 7,848**	$ 5,171
Income and other taxes payable	**3,364**	318
Current portion of long-term debt	**380**	305
	11,592	5,794
LONG-TERM DEBT (Note 4)	**87,553**	46,823
DEFERRED INCOME TAXES (Note 5)	**25,061**	21,767
SHAREHOLDERS' EQUITY		
Share capital (Note 6)		
5½% cumulative redeemable preferred shares—16,628 shares (1982—20,589)	**831**	1,029
Class B junior preferred shares—1,000,000 shares	**20,000**	—
Common shares—5,722,865 shares	**23,511**	23,511
Capital redemption reserve fund	**–**	2,471
Contributed surplus	**125**	90
Retained earnings	**57,705**	39,150
	102,172	66,251
	$226,378	$140,635

On behalf of the Board:

Director Director

See accompanying notes.

CONSOLIDATED STATEMENT OF INCOME

	Years ended December 31 (in thousands) 1983	1982	1981
Revenue			
Gas and oil, net	**$32,626**	$21,921	$15,228
Pipeline operations	**6,577**	5,842	6,076
Investment and other income	**7,538**	3,631	1,482
	46,741	31,394	22,786
Expenses			
Operating	**4,659**	4,462	2,899
Gas purchased for resale	**4,464**	4,374	4,910
Administrative	**1,595**	1,143	1,071
Interest on long-term debt	**7,940**	1,802	1,523
Depreciation and depletion	**3,232**	2,144	1,820
	21,890	13,925	12,223
Income from continuing operations	**24,851**	17,469	10,563
Gain on sale of coal properties	**—**	—	8,010
Income before taxes	**24,851**	17,469	18,573
Income and resource taxes (Note 5)			
Current	**1,362**	648	1,680
Deferred	**3,294**	3,302	5,635
Petroleum and gas revenue tax	**3,618**	1,625	1,228
	8,274	5,575	8,543
Income before the undernoted	**16,577**	11,894	10,030
Equity in operating income of affiliate	**—**	—	1,699
Income before extraordinary items	**16,577**	11,894	11,729
Extraordinary items (Note 7)	**—**	—	(982)
Net income	**$16,577**	$11,894	$10,747
Basic income per common share			
Income before extraordinary items	**$ 2.81**	$ 2.07	$ 2.21
Extraordinary items	**—**	—	(.19)
Net income	**$ 2.81**	$ 2.07	$ 2.02
Fully diluted income per common share	**$ 2.35**		

See accompanying notes.

CONSOLIDATED STATEMENT OF CHANGES IN FINANCIAL POSITION

	Years ended December 31 (in thousands) 1983	1982	1981
SOURCE OF FUNDS			
Funds provided from operations	**$ 23,103**	$17,328	$ 9,475
Proceeds on:			
Sale of properties and other assets	**123**	73	8,610
Sale of common shares	**—**	28	211
Issue of convertible debentures	**41,460**	—	—
Issue of Class B junior preferred shares	**20,000**	—	—
Redemption of investment in affiliate	**—**	16,900	1,500
Sale of long-term investments	**41,279**	—	—
Increase in long-term debt	**—**	41,359	—
Proceeds on sale of investment in affiliate, net	**—**	—	22,447
Assumption of long-term debt of affiliate	**—**	—	8,093
Reclassification of long-term investments (Note 2)	**25,796**	—	—
Current liabilities increase (decrease)			
Accounts payable	**2,677**	1,316	405
Due to affiliate	**—**	—	(1,331)
Income and other taxes payable	**3,046**	(1,611)	1,494
Long-term debt due within one year	**75**	305	—
Total funds provided	**157,559**	75,698	50,904
USE OF FUNDS			
Purchase of long-term investments	**—**	67,075	19,219
Expenditures for property, plant and equipment	**16,490**	9,316	18,165
Reduction of long-term debt	**730**	305	9,600
Redemption of preferred shares	**163**	35	100
Dividends on preferred shares	**493**	58	62
Current assets increase (decrease)			
Accounts receivable	**3,806**	917	1,918
Current portion of long-term investments	**—**	(1,000)	1,000
Prepaid expenses	**26**	(8)	(119)
Total funds used	**21,708**	76,698	49,945
Increase (decrease) in cash and investments	**135,851**	(1,000)	959
Cash and investments, beginning of year	**95**	1,095	136
Cash and investments, end of year	**$135,946**	$ 95	$ 1,095

See accompanying notes.

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

	1983	1982	1981
	Years ended December 31 (in thousands)		
Balance, beginning of year	**$39,150**	$27,367	$16,814
Net income	**16,577**	11,894	10,747
Transfer from capital redemption reserve fund (Note 6)	**2,493**	—	—
	58,220	39,261	27,561
Deduct			
Transfer to capital redemption reserve fund	**22**	53	132
Dividends on preferred shares	**493**	58	62
Balance, end of year	**$57,705**	$39,150	$27,367

See accompanying notes.

AUDITORS' REPORT

To the Shareholders of
North Canadian Oils Limited

We have examined the consolidated balance sheet of North Canadian Oils Limited as at December 31, 1983 and the consolidated statements of income, retained earnings and changes in financial position for the year then ended. Our examination was 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, these consolidated financial statements present fairly the financial position of the Company as at December 31, 1983 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

The consolidated balance sheet of North Canadian Oils Limited as at December 31, 1982 and the consolidated statements of income, retained earnings and changes in financial position for the years ended December 31, 1982 and 1981 were examined by other auditors whose report dated March 2, 1983 expressed an unqualified opinion on those financial statements.

Calgary, Alberta
March 15, 1984

Touche Ross & Co.
Chartered Accountants

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

North Canadian Oils Limited is authorized to conduct business under the Canada Business Corporations Act, and is principally engaged in the exploration for, and production of, oil and gas in North America.

These consolidated financial statements are stated in Canadian dollars and have been prepared in accordance with accounting principles generally accepted in Canada and except as indicated in Note 11, with accounting policies generally accepted in the United States. A summary of the Company's significant accounting policies is described below.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. Certain items in the consolidated financial statements of prior years have been reclassified to conform to the presentation adopted for the current year.

Oil and Gas Operations

The Company follows the full cost method of accounting for exploration and development expenditures, wherein all costs related to the exploration for and development of oil and gas reserves in North America are capitalized. These costs include leasehold acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells, oil and gas field production equipment, gathering lines, compressors and gas plants, and overhead expenses related to exploration activities after deducting related government grants. All such costs are being amortized on the unit-of-production method based on estimated proven recoverable reserves. Proceeds from disposal of properties are normally deducted from the full cost pool without recognition of gain or loss.

Pipeline assets are depreciated over the term of the existing gas contracts and other equipment is depreciated over the estimated useful lives of the assets. Leasehold improvements are amortized over the term of the lease.

Investments

Investments are valued at the lower of cost and estimated net realizable value.

Income Per Share

Basic income per common share is computed by dividing net income, after provision for preferred dividend requirements, by the weighted average number of common shares and common share equivalents outstanding (1983—5,723,644; 1982—5,723,483; 1981—5,308,759). Fully diluted income per common share has been computed as above and also assumes the conversion of all instruments effective the date of issue (weighted average of 7,480,406 shares) and the related adjustments to net income.

2. INVESTMENTS

	1983	1982
	(in thousands)	
Current		
No quoted market value	**$135,946**	$ —
Long-term		
Quoted market value—$36,842,000	—	36,179
No quoted market value	—	30,896
	$ —	$67,075

The investments held at December 31, 1983, are readily marketable and therefore, the remaining investment in the amount of $25,796,000 held at December 31, 1982 has been reclassified into current assets.

3. PROPERTY, PLANT AND EQUIPMENT

	Canada	U.S.A.	Total
		(in thousands)	
December 31, 1983			
Petroleum and natural gas leases, rights, exploration and development costs and related equipment thereon	**$83,452**	**$7,518**	**$90,970**
Accumulated depreciation and depletion	**14,421**	**585**	**15,006**
	69,031	**6,933**	**75,964**
Pipeline, other equipment and leasehold improvements	**6,522**	—	**6,522**
Accumulated depreciation and depletion	**4,339**	—	**4,339**
	2,183	—	**2,183**
	$71,214	**$6,933**	**$78,147**

	Canada	U.S.A.	Total
		(in thousands)	
December 31, 1982			
Petroleum and natural gas leases, rights, exploration and development costs and related equipment thereon	$68,781	$6,934	$75,715
Accumulated depreciation and depletion	11,698	338	12,036
	57,083	6,596	63,679
Pipeline, other equipment and leasehold improvements	5,302	—	5,302
Accumulated depreciation and depletion	4,090	—	4,090
	1,212	—	1,212
	$58,295	$6,596	$64,891

Grants under petroleum incentive programs aggregating $2,845,000 in 1983 and $1,833,000 in 1982 have been accrued in accordance with the regulations and treated as a reduction in the cost of related exploration and development expenditures.

4. LONG-TERM DEBT

	1983	1982
	(in thousands)	
11¼% sinking fund debentures	**$ 4,905**	$ 5,748
Floating rate convertible debentures	**21,460**	—
8% convertible debenture	**20,000**	—
Bank indebtedness	**41,568**	41,380
	87,933	47,128
Less current portion of long-term debt	**380**	305
	$87,553	$46,823

The 11¼% sinking fund debentures are secured by certain gas properties and are redeemable at 105% of the principal amount to August 31, 1984 declining by 1.25% annually to 100% in the year ending August 31, 1988. In addition, the Company is required to make sinking fund payments sufficient to retire on August 31, in each of the years 1984 to 1987 inclusive, $917,000 principal amount of debentures and $1,775,000 in 1988. The 1984 requirement has been purchased to the extent of $538,000.

The floating rate convertible debentures bear interest at the average prime rate of a Canadian chartered bank, mature on April 30, 1988 and are convertible after December 31, 1984 into common shares of the Company at a price of $15 per share. Of the total, $6,345,000 is payable to a related party.

The 8% convertible debenture is due September 2, 1993 and is convertible into Class B junior preferred series 2 shares at a price of $25 per share, each of which in turn is convertible into one common share of the Company, all prior to September 2, 1993. Under certain conditions, the debenture and preferred shares are redeemable by the Company.

The Company has lines of credit in the amount of $105,000,000 which when drawn down bear interest at rates from prime to prime plus ½%, and are repayable on demand. The Company's bankers have agreed not to require repayment of the bank indebtedness prior to December 31, 1984 and accordingly the indebtedness has been classified as long-term.

5. INCOME AND RESOURCE TAXES

The provisions made for income taxes differ from the amounts which would have been expected if it were assumed that the reported pretax earnings were subject to the Canadian federal statutory income tax rate for the year. The principal reasons for the differences between such "expected" income tax provisions and the amounts actually provided are as follows:

	1983	1982	1981
		(in thousands)	
Computed "expected" income tax at 48%	**$10,167**	$7,605	$8,325
Increase (decrease) in income taxes resulting from:			
Non-deductibility of royalties and other payments to the crown	**3,384**	2,351	2,119
Federal resource allowances	**(3,638)**	(2,356)	(1,654)
Allowance for earned depletion	**(107)**	(181)	(105)
Provincial taxes less federal abatement	**291**	194	246
Provincial rebates and credits	**(1,504)**	(2,308)	(1,179)
Non-taxable Canadian dividends	**(4,357)**	(1,598)	(515)
Petroleum and gas revenue tax	**3,618**	1,625	1,228
Other	**420**	243	78
Actual income tax provision	**$ 8,274**	$5,575	$8,543

Deferred income taxes arise from differences in the rates at which certain costs have been written off for tax purposes and for financial reporting purposes. The principal items which give rise to such timing differences, and the amount of deferred income taxes attributable thereto, are as follows:

	1983	1982	1981
		(in thousands)	
Excess of capital cost allowances deducted for income tax purposes over depreciation recorded in the accounts	**$ 420**	$ 411	$ 800
Excess exploration and development expenses and lease acquisition costs deducted for income tax purposes over depletion and amortization recorded in the accounts	**2,874**	2,891	4,835
Total deferred income taxes	**$3,294**	$3,302	$5,635

6. SHARE CAPITAL

Authorized share capital

As approved by the shareholders, the Company was continued under the Canada Business Corporations Act with an authorized capital of 20,149 5½% cumulative redeemable sinking fund preferred shares, each share having a par value of $50, 10,000,000 Class A and 10,000,000 Class B junior preferred shares issuable in series, 20,000,000 Class A shares and 20,000,000 common shares each without nominal or par value. On continuance, the capital redemption reserve fund in the amount of $2,493,000 was transferred to retained earnings.

5½% Cumulative Redeemable Preferred Shares

The terms of these preferred shares require the Company to purchase for cancellation 2,000 preferred shares in each year. The shares may be redeemed at par from the holders on 30 days notice or purchased on the market. At December 31, 1983 the requirements have been met for the year ending June 1, 1984 and 1,372 shares applicable to the year ending June 1, 1985 have been cancelled. The preferred share indenture imposes certain restrictions on the payment of common share dividends. During 1983, 3,961 preferred shares (1982—1,062; 1981—2,634) were redeemed and the difference between the acquisition cost and the par value of the preferred shares redeemed of $35,000 (1982—$18,000; 1981—$32,000) was credited to contributed surplus.

Class B Junior Preferred Series 1

The Class B junior preferred shares series 1 rank junior to the 5½% cumulative redeemable preferred shares with respect to all rights, privileges, restrictions and other conditions. Each Class B junior preferred share series 1 is convertible into one common share after December 31, 1984 and prior to April 1, 1993. These shares are redeemable by the Company under certain conditions.

Common Shares Reserved

The Company has reserved for issue a total of 3,248,700 common shares under conversion rights of the issued junior preferred shares, convertible debentures, and outstanding stock options.

7. EXTRAORDINARY ITEMS

	1981
	(in thousands)
Loss on sale of investment in affiliate (including related income taxes of $226,000)	$(2,335)
Deduct: Equity in extraordinary items of affiliate:	
Reduction of income taxes on application of losses brought forward	941
Gain on sale of investments	412
Net loss	$ (982)

8. STOCK OPTION PLAN

The Employee Stock Option Plan expired during 1983 and the unexercised stock options totalling 18,000 common shares (1982—18,000) expire in 1986 and 1987. In 1982, 3,000 common shares (in 1981—23,700) were issued for a total consideration of $28,000 (1981—$211,000) under this plan.

Notes receivable in respect of the stock option plan in the amount of $220,000 at December 31, 1983 and $382,000 at December 31, 1982 are due from directors, officers, a retired director and the estate of a deceased officer and are carried on the balance sheet under other assets.

9. OTHER INFORMATION

Employee Profit Sharing Plan

The Company adopted an Employee Profit Sharing Plan in 1979 which is available to technical and other personnel directly involved in exploration and development. Contributions to the plan by the Company may be made in cash or as a royalty interest in petroleum natural gas and related hydrocarbons attributable to the Company's interest in certain non-producing exploration lands. The Company's contributions to the plan in 1983 and 1982 consisted of a gross overriding royalty interest having a nominal fair market value at the time of contribution. The royalty interest vests in each participant at the rate of 20% per year until fully vested; however, all amounts received in respect of the contingently vested portion of any royalty interest is fully vested as and when received.

Related Party Transactions

In 1982 the company made the following transactions with related parties; purchase of long-term investments for a cost of $60,896,000, sale of long-term investments (at no gain or loss) for proceeds of $30,000,000. The long-term investment with a carrying value of $36,179,000 is preferred shares of a related party. The Company received dividends of $1,061,000 with respect to this investment in the year ended December 31, 1982. Three directors of the Company are officers of certain of the related parties.

In 1981, the Company sold its investments in an affiliate for a consideration of $23,400,000 to a corporation holding 1,488,286 common shares of the Company. Such corporation is wholly owned by a director of the Company. Immediately prior to the sale, the Company reacquired from the affiliate certain gas property interests for a consideration of $8,093,000 and assumed the affiliate's 11¼% debentures in the amount of $8,093,000 (including $2,325,000 of such debentures held by the Company) secured by the gas property interests. The gas properties were assigned a carrying value of $7,274,000 being the Company's cost of investment in the affiliate at the date of sale. The Company, from the proceeds of the sale purchased 736,000 redeemable preference shares of the affiliate having an aggregate par value of $18,400,000. During 1982 the affiliate redeemed all the preference shares at par.

The Company accrued or paid professional service fees aggregating $237,000, $157,000 and $517,000 to three legal firms in which certain directors of the Company are partners for the years ended December 31, 1983, 1982 and 1981 respectively.

During 1983, the Company issued $11,540,000 floating rate convertible debentures to affiliated companies and paid interest of $828,000 related to this debt. At December 31, 1983, $6,345,000 was held by a related party. The Company received from an affiliate $87,000 in respect of interest on debentures for the year ended December 31, 1981 and $836,000 in preferred share dividends for the year ended December 31, 1982.

Pension Plan

The Company pension plan, which is available to all employees, was amended during 1983 to a defined benefit plan. Based on an actuarial evaluation, the unfunded liability at December 31, 1983 was approximately $440,000 which is being funded and charged to earnings over a fourteen year period.

10. DEPENDENCE UPON LIMITED CUSTOMERS

Three customers to whom the Company sold natural gas accounted individually for more than 10% of gross revenue as follows:

	Amounts		% of Total revenue	
	1983	1982	1983	1982
	(in thousands)			
Company				
TransCanada PipeLines Limited	**$18,063**	$17,337	**46**	55
Saskatchewan Power Corporation	**14,502**	5,511	**37**	18
St. Regis (Alberta) Ltd.	**4,784**	3,317	**12**	10
Total	**$37,349**	$26,165	**95**	83

11. UNITED STATES ACCOUNTING PRINCIPLES DIFFERENCES

The accounting principles followed in the preparation of the financial statements of the Company and the affiliate accounted for on the equity method differ in certain respects from accounting principles generally accepted (GAAP) in the United States. Such differences relate to the financial statements of the affiliate accounted for by the equity method in 1981. The aggregate effect of the adjustments on reported income for the year ended December 31, 1981 would be to reduce income before the understated of $10,030,000 and extraordinary items of ($982,000) to $7,694,000 and nil respectively, and to increase the equity in operating income of the affiliate from $1,699,000 to $3,053,000.

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Three months ended (in thousands)			
	March 31	June 30	September 30	December 31
1983				
Net revenue	**$10,889**	**$10,718**	**$10,326**	**$14,808**
Net income	**$ 4,031**	**$ 4,242**	**$ 3,079**	**$ 5,225**
Net income per common share				
Basic	**$ .70**	**$ .74**	**$ .54**	**$ .83**
Fully diluted	**$ .70**	**$ .61**	**$ .36**	**$ .68**
1982				
Net revenue	$ 7,422	$ 7,970	$ 7,230	$ 8,772
Net income	$ 2,671	$ 3,328	$ 2,653	$ 3,242
Net income per common share after preferred share dividends	$ .46	$ .58	$ .46	$ .57

13. DISCLOSURE OF OIL AND GAS PRODUCING ACTIVITIES AS REQUIRED BY STATEMENT OF FINANCIAL ACCOUNTING STANDARD NO. 69

Capitalized costs relating to oil and gas producing activities.

At December 31, 1983 and 1982 there were no significant unproved oil and gas properties included in capitalized costs relating to oil and gas properties.

Costs incurred in oil and gas property acquisitions, exploration and development activities for the years ended December 31:

	Canada	U.S.A.	Total
		(in thousands)	
1983			
Acquisition of properties	**$2,898**	**$ 38**	**$2,936**
Exploration	**2,484**	**193**	**2,677**
Development	**9,648**	**4**	**9,652**
1982			
Acquisition of properties	817	202	1,019
Exploration	2,393	189	2,582
Development	4,978	—	4,978
1981			
Acquisition of properties	904	974	1,878
Exploration	894	988	1,882
Development	4,893	—	4,893

Results of operations for producing activities ending December 31:

	Canada	U.S.A.	Total
1983			
Revenue			
Sales (net)	**$31,997**	**$ 629**	**$32,626**
Production costs	**4,074**	**93**	**4,167**
Depreciation and depletion	**2,844**	**247**	**3,091**
	25,079	**289**	**25,368**
Income tax expenses	**4,656**	**—**	**4,656**
Results of operations from producing activities (excluding corporate overhead and interest costs)	**$20,423**	**$ 289**	**$20,712**
1982			
Revenue			
Sales (net)	$21,622	$ 299	$21,921
Production costs	4,370	92	4,462
Exploration costs	2,393	189	2,582
Depreciation and depletion	1,965	179	2,144
	12,894	(161)	12,733
Income tax expenses	4,510	—	4,510
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 8,384	$ (161)	$ 8,223
1981			
Revenue			
Sales (net)	$17,366	$ 117	$17,483
Production costs	2,991	67	3,058
Exploration costs	894	988	1,882
Depreciation and depletion	1,735	159	1,894
	11,746	(1,097)	10,649
Income tax expenses	4,100	—	4,100
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 7,646	$(1,097)	$ 6,549

For the year 1981, $146,000 of development expenditures, $1,883,000 of net sales, $159,000 of production costs and $74,000 of depreciation and depletion attributable to an affiliate of the Company have been included as part of the Canadian producing activities.

Quantities of oil and gas reserves as at December 31 for Canada (unaudited).

	1983		1982		1981	
	Oil*	Gas**	Oil*	Gas**	Oil*	Gas**
Beginning of year	**1,313,137**	**590.9**	1,210,282	604.4	568,993	560.0
Revision of previous estimates	**(44,956)**	**(0.5)**	—	—	125,437	(9.3)
Improved recovery	**—**	**—**	—	—	559,000	—
Purchase of minerals-in-place	**—**	**—**	—	—	—	69.5
Extensions and discoveries	**65,940**	**5.9**	158,051	3.6	—	—
Production	**(110,774)**	**(17.5)**	(55,196)	(17.1)	(43,148)	(15.8)
Sales of minerals-in-place	**—**	**—**	—	—	—	—
End of year	**1,223,347**	**578.8**	1,313,137	590.9	1,210,282	604.4

There were no long-term supply agreements with foreign governments. There were no significant foreign geographic reserves.

*Oil stated in barrels before royalty interests.

**Gas stated in billion cubic feet before royalty interests.

Standard measure of discounted net cash flows and changes therein relating to proved oil and gas reserves at December 31 (unaudited).

	1983	1982	1981
		(in thousands)	
Future cash inflows	**$1,106,872**	$689,553	$674,475
Future production and development costs	**323,994**	230,587	267,147
Future income tax expenses	**301,472**	144,402	142,565
Future net cash flows	**481,406**	314,564	264,763
10% annual discount for estimated timing of cash flows	**312,915**	191,670	166,875
Standardized measure of discounted net cash flows	**$ 168,491**	$122,894	$ 97,888

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

	1983	1982	1981
		(in thousands)	
Sales and transfers of oil and gas produced, net of production costs	**$(28,459)**	$(17,459)	$(14,128)
Net changes in prices and production costs	**315,423**	50,794	85,828
Extensions, discoveries, and improved recovery, less related costs	**6,858**	3,551	691
Development costs incurred during the period	**(9,652)**	(4,978)	(4,839)
Accretion of discount	**12,289**	9,789	9,507
Net changes in income taxes	**(157,070)**	(1,837)	(80,935)
Other	**(93,792)**	(14,854)	6,057

Amortization per equivalent physical unit of production (Mcf):

	1983	1982	1981
Depreciation and depletion	**$ .13**	$ .11	$ .09

ACCOUNTING FOR THE EFFECTS OF CHANGING PRICES —Supplemental Information (Unaudited)

The Canadian Institute of Chartered Accountants (CICA) recommends the disclosure of supplementary financial information on a current cost basis commencing with the fiscal year ended December 31, 1983. The CICA deemed this disclosure necessary to reflect the economic effects of changes in the general purchasing power of the monetary unit and changes in specific prices of goods and services during periods of significant inflation.

The Company generally supports the initiative in requiring companies to disclose information of the effects of changing prices. However, it is the opinion of the Company that further work is required in the area of specialized assets, as in the oil and gas industry, in order to provide more meaningful information to the reader.

It is, therefore, important to recognize that this information is, at best, an approximation of replacing the Company's existing assets, in the same location and having the same earning capacity, at December 31, 1983 prices and in no way does it represent the fair market value of these assets.

The recommendations of the CICA have generally been adopted in preparing information on the effects of changing prices. The Company, however, has made certain subjective modifications as allowed by the CICA guidelines which are presented below.

The Company follows the full cost method of accounting for oil and gas properties. The historical costs for property, plant and equipment have been adjusted by the consumer price index instead of by a specific price index for each class of asset. Fixed assets, other than property, plant and equipment, which represent less than 5% of total assets, have not been adjusted, as it is the opinion of the Company that the historical costs approximate current costs.

Depreciation, depletion and income taxes have been calculated on the same basis as for historical costs but using the current cost base. No adjustment to the income tax expense has been made as per the CICA guidelines. Taxes would have been reduced if an adjustment had been made.

Financing adjustments reflect the benefit or cost to common shareholders of using borrowed funds to finance the purchase of fixed assets during inflationary periods. Although this concept might have certain theoretical validity, it has not received professional acceptance because of its controversial nature. In contrast to financing adjustments the gain in general purchasing power arises due to the fact that during periods of significant inflation the value of the monetary unit declines. Therefore, if the monetary liabilities exceed the monetary assets, as in the case of the Company, a gain will result.

STATEMENT OF INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS ON A CURRENT COST BASIS (in thousands)

Historical income for the year		$16,577
Less: Preferred share dividend		(493)
Historical cost income attributable to common shareholders		$16,084
Less: Current cost adjustments		
Depreciation and depletion	$1,001	
Financing adjustment	(240)	
		(761)
Income attributable to common shareholders on a current cost basis		$15,323

The financing adjustment amounts to $8,735,000 based on the amount of changes during the reporting period in the current cost amounts of property, plant and equipment.

Other supplementary information

Increase in the current cost amounts of property, plant and equipment due to the effects of general inflation	$ 5,877
Gain in general purchasing power from holding net monetary liabilities	$ 2,426

Schedule of Fixed Assets—1983

	Historical Costs	Current Costs
Property, plant and equipment—net	$ 78,147	$114,542
Net assets (common shareholders' equity)	$102,172	$180,028

DIRECTORS

DONALD F. CHRISTENSEN
Senior Vice President, Operations
of the Company
Calgary, Alberta

MICHAEL A. CORNELISSEN
President and Chief Executive Officer of
Royal Trustco Limited
Toronto, Ontario

* MARSHALL A. JACOBS
Senior Partner, Jacobs Persinger & Parker
New York, New York

* JAMES F. KAY
Chairman of the Board of Dylex Limited
Toronto, Ontario

*■★ DAVID W. KERR
Executive Vice President and
Chief Operating Officer of
Hees International Corporation
Toronto, Ontario

WILLARD J. L'HEUREUX
Senior Vice President of
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Senior Vice President, Finance &
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■★ HAROLD P. MILAVSKY
President and Chief Executive Officer of
Trizec Corporation
Calgary, Alberta

* Member of Executive Committee
■ Member of Compensation Committee
★ Member of Audit Committee

FORM 10K

North Canadian Oils Limited will furnish upon written request to any registered shareholder, without charge, a copy of its most recent Annual Report - Form 10K, as filed with the United States Securities and Exchange Commission.

OFFICERS

DONALD F. CHRISTENSEN
Senior Vice President, Operations

BENJAMIN L. COOK
Vice President, Land

BILL A. KURUCZ
Controller/Treasurer

CHARLES K. LOUGH
Senior Vice President, Finance and
Administration

W. KEITH MILLER
Vice President, Marketing

REGISTRARS AND TRANSFER AGENTS
GUARANTY TRUST COMPANY OF CANADA
Calgary and Toronto

The BANK of NOVA SCOTIA TRUST COMPANY
of NEW YORK (Common Shares Only)
New York, New York

PREFERRED SHARE REGISTRAR AND TRANSFER AGENT
GUARANTY TRUST COMPANY OF CANADA
Calgary and Toronto

COMMON SHARES LISTED
TORONTO STOCK EXCHANGE (NCOT)
AMERICAN STOCK EXCHANGE (NCD)

PREFERRED SHARES LISTED
TORONTO STOCK EXCHANGE

AUDITORS
TOUCHE ROSS & CO.
Calgary, Alberta

BANKERS
BANK of MONTREAL
CONTINENTAL BANK of CANADA

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