NORTH CANADIAN OILS LIMITED

1986 Annual Report

Contents

The Company

North Canadian Oils Limited is an oil and gas exploration and development company whose activities are primarily concentrated in the Western Canadian Sedimentary Basin. The Company's net proven natural gas reserves are the 19th largest in Canada and it ranks 12th in natural gas production. The Company is also involved in the mining of lead and zinc through its 87% owned subsidiary, Bankeno Resources Limited.

The largest shareholder is Hees International Corporation, a Canadian company. Hees provides a wide range of merchant banking services to a select group of clients and invests in established companies where it believes its initiatives can enhance values. Hees owns 33% (directly and indirectly) of the common shares of NCO.

For the year ended December 31, 1986, the Company had \$761 million in assets, \$60 million in annual cash flow and \$17 million in net earnings. Long-term debt was \$211 million but was completely offset by \$274 million of securities providing a debt free balance sheet.

Exchange Rates

Range of spot prices for the Canadian dollar in United States dollars (rounded to the nearest cent).

	High	Low	Close	Average
1982	\$0.84	\$0.77	\$0.81	\$0.81
1983	0.82	0.80	0.80	0.81
1984	0.80	0.75	0.76	0.77
1985	0.76	0.71	0.72	0.73
1986	0.73	0.69	0.72	0.72

Noon buying rate on March 11, 1987 was \$0.75.

Annual Meeting

The Annual and Special Meeting of North Canadian Oils Limited will be held in the Lakeview Room of the Westin Hotel in Calgary, Alberta at 9:00 a.m. on May 21, 1987.

Metric Conversion

The measurements presented in this report are in the Imperial system of Units. The table below is provided to assist in converting to the International measurement system equivalents.

To convert from	to	Multiply by
Barrels (bbls)	Cubic metres (m^3)	0.1590
Thousand cubic feet (mcf)	Thousand cubic metres (10^3m^3)	0.0282
Acres (ac)	Hectares (ha)	0.4050

Highlights

	Years Ended December 31	
	1986	1985
Financial		
(Dollars in thousands except per share amounts)		
Gross revenues net of royalties	**$112,160**	$143,748
Net earnings	**16,825**	22,966
Per common share		
— Basic	**0.30**	1.21
— Fully diluted	**0.30**	1.10
Cash flow	**60,232**	71,959
Dividends on preferred shares	**13,224**	9,881
Capital expenditures	**31,812**	51,474
Investments and note receivable	**274,337**	313,397
Long-term debt	**211,344**	327,622
Shareholders' equity	**433,633**	290,917
Number of common shares outstanding	**18,434,217**	10,821,739
Operating		
Production		
Natural gas		
Millions of cubic feet	**47,687**	48,624
Millions of cubic feet per day	**131**	133
Crude oil and natural gas liquids		
Barrels	**840,261**	747,767
Barrels per day	**2,302**	2,050
Reserves		
Natural gas, billions of cubic feet		
Proved	**760**	784
Probable	**128**	130
Crude oil, thousands of barrels		
Proved	**6,478**	5,329
Probable	**1,126**	1,269
Finding costs ($ per equivalent barrel)	**4.44**	3.67
Land holdings (thousands of acres)		
Gross	**4,047**	3,653
Net	**1,708**	1,633
Wells drilled		
Gross	**192**	286
Net	**79**	153
Number of employees	**221**	242

Report to Shareholders

The new NCO made good progress during 1986 despite the downturn in the Industry caused by the severe drop in oil and natural gas prices. Because of our financial and operational strengths we were able to maintain an active exploration and development program. For the future, we believe our competitive advantages will ensure our success in the new, highly volatile, commodity based, deregulated environment now faced by the Industry.

Our view is that oil prices will continue to fluctuate for the foreseeable future but prices for natural gas will bottom out in 1987. Increased demand from the United States commencing in 1988 will improve volumes and cause prices to firm. We are poised to take advantage of that upturn because of our large natural gas reserve base, our excess deliverability, our significant inventory of undeveloped land, and our marketing initiatives. In the meantime, our low cost existing reserve base allows us to be competitive in the current market thereby continuing to generate substantial cash flow with which to carry on an active exploration and development program.

The amalgamation of Merland Explorations Limited with NCO, which was effective July 1, 1986, has been a great success. The two employee groups have been combined into an effective team and morale in the Company is high. All employees are to be congratulated on making the amalgamation work. NCO now has the financial strength to weather the down cycles in the Industry and the technical skills to take full advantage of exploration and development opportunities.

Although gross revenues, net earnings and cash flow are all down compared to 1985, it is significant that NCO remained profitable and generated substantial cash flow during 1986. Since the amalgamation, the capital structure has been further improved through the conversion of $50 million of debentures into common shares and the issuance of $7.4 million of common shares at a premium as part of a sale of investment tax credits not required by the Company. NCO's shareholders' equity now stands at $434 million, which provides a solid base for the future.

During 1986, long-term debt was reduced by $116 million and stood at $211 million at year end. However, this debt was completely offset by an investment portfolio plus note receivable of $274 million providing a debt free balance sheet. Since year end a further $50 million of the investment portfolio has been sold with the proceeds again being used to reduce long-term debt. As of March 1st the investment portfolio plus note receivable were $212 million and long-term debt was $148 million.

Natural gas production during 1986 of 131 million cubic feet per day (mmcfd) was close to 1985 levels of 133 mmcfd. The Company, through its marketing initiatives, was able to substantially offset reduced takes by its major purchaser. Crude oil and natural gas liquids production increased from 2,050 barrels of oil per day (bopd) in 1985 to 2,302 bopd in 1986.

We used the amalgamation as an opportunity to take a fresh look at the organizational structure, our management philosophy and future strategies. Management personnel were reassigned for greater efficiency. For example, senior operating personnel were moved from Calgary to our District Offices to provide for more immediate, on the spot, decision making. We have put into place a revised benefits package, a new stock option plan that applies to all employees and a salary administration program that is performance based.

We have also recognized how important Saskatchewan is to the Company by opening a corporate office in Regina and a new operations office in Richmond. In addition, Mr. Paul J. Hill, a prominent businessman from Regina, is standing for election to the Board of Directors. Some 41% of our natural gas reserves and 30% of our natural gas production are in Saskatchewan. Also, 26% of our oil reserves and 40% of our oil production are in that province. We see major opportunities to increase both reserves and production in Saskatchewan as a result of changing energy policy which will encourage direct sales within the province and sales to eastern Canada and the United States. We have uncontracted gas available in Saskatchewan which will allow us to take advantage of these markets.

Following the amalgamation on July 1, 1986, we sent to all shareholders a corporate profile on the new NCO. In that profile we set out some short and long-term strategies. It is now time to be accountable and we would like to bring you up-to-date on what has been accomplished:

— by year end, marketing initiatives increased direct sales of natural gas in Alberta from 1.3 mmcfd to 13 mmcfd and at times reached 30 mmcfd. In addition, contracts have been signed for the delivery of 15 mmcfd of natural gas to industrial customers in Ontario;

— 226 thousand gross acres (138 thousand net acres) of prospective land was acquired for approximately 50% of land costs in 1985;

— low cost gas reserves have been developed and placed on stream using existing facilities, particularly in the Hatton area of Saskatchewan;

— our strong technical staff have made significant oil and gas finds which will be reflected in 1987 and beyond;

— operating and administrative expenses have been reduced by about 10%;

— operatorship has been maintained at above industry averages, with 83% of gas production and 59% of oil production coming from NCO operated wells;

— exploration and development expenditures were maintained within self-generated cash flow.

Our objectives for 1987 are as follows:

— aggressively seek out additional gas sales in Alberta, Saskatchewan, eastern Canada and the United States;

— increase the search for new natural gas reserves so as to be well positioned for the increased demand expected from the United States in 1988 and beyond;

— continue to look for and develop low cost conventional crude oil so as to increase cash flow by taking advantage of immediate assured sales;

— continue the program of acquiring quality exploratory land;

— carefully examine acquisition opportunities which can add reserves and cash flow to the Company;

— continue the program of reducing operating and administrative expenses;

— take further steps to increase the awareness of the new NCO in the investment and business community.

The strength of an oil and gas company's technical staff is demonstrated by its drilling success and finding costs. NCO continued to perform at above industry averages with the success ratio for exploratory wells at 67% and for development wells at 89%. Finding costs were approximately 70% of the industry average.

The mix and quality of a company's land inventory is also critical and NCO has an excellent balance with 863,000 net acres of undeveloped land and 845,000 net acres of developed land. The large inventory of undeveloped land is the Company's future upside potential.

Proved and probable reserves are a key asset and the objective is to add more reserves each year than are produced. During 1986, NCO increased its proved and probable reserves of crude oil and natural gas liquids from 6.6 million to 7.6 million barrels. Natural gas reserves decreased from 914 to 888 bcf in 1986. Under normal circumstances this would be cause for concern, however, in a deregulated, oversupply environment, the market becomes the overriding force. The Company, having excess natural gas deliverability, chose not to replace reserves for which it had no immediate market, but instead to intensify marketing initiatives. As new markets develop, the Company can add substantial low cost gas reserves from its large inventory of undeveloped lands.

Outlook

The outlook for NCO is a bright and exciting one. We view the current environment as an opportunity and intend to take full advantage of it. We believe we can show continued good progress for the following reasons:

— the Company has a debt free balance sheet on a net basis and substantial shareholders' equity;

— the size and liquidity of the investment portfolio allows us to pursue attractive acquisition opportunities;

— the Company has a large reserve base in natural gas with excess deliverability which means we can take full advantage of the projected increase in demand from the United States;

— a number of marketing initiatives are underway to ensure we fully participate in natural gas sales opportunities;

— the Company has been successful in finding low cost conventional crude oil which can be sold profitably at current price levels;

— we have a capable, hard working staff who have the same motivation for success as all shareholders.

The shareholders will be asked to increase the Board of Directors from nine to ten members at the Annual and Special Meeting. Mr. Paul J. Hill, President of McCallum Hill Limited of Regina and Mr. Paul M. Marshall, Vice Chairman of Brascan Limited of Toronto, are new directors standing for election. Mr. E. Donald Patterson of Toronto is not standing for re-election and we thank him for his significant contribution to the Board.

We are confident we can add real value for shareholders during 1987 and beyond.

On behalf of the Board.

Norman R. Gish
President

March 23, 1987
Calgary, Canada

Operations Review

Marketing

Deregulation within the Canadian Energy Industry has created new marketing challenges for oil and gas producers. Approximately 90% of the Company's natural gas reserves are dedicated under long-term contracts. Requested deliveries have been less than one-half contracted volumes and are expected to remain at these low levels for the next two years.

In response to these conditions, the Company expanded its marketing efforts both within Alberta, for gas excess to contract volumes, and outside the province for uncontracted reserves.

Within Alberta, the Company has established itself as a reliable supplier of natural gas. The 1986 direct sales of natural gas averaged 13 mmcfd, peaking at 30 mmcfd by year end. This was a ten-fold increase over 1985 direct sales volumes.

The Company has been actively pursuing markets in eastern Canada and the United States. It is currently selling an average of 15 mmcfd to industrial consumers in Ontario. This gas comes from producing properties in both Alberta and Saskatchewan.

Natural Gas Sales — Major Purchasers

	Years ended December 31			
	1986		1985	
	mmcfd	%	mmcfd	%
TCPL	**61.5**	**47**	70.7	53
SPC	**39.0**	**30**	42.8	32
Intra Alberta	**13.0**	**10**	1.3	1
Other	**17.1**	**13**	18.4	14
	130.6	**100**	133.2	100

Average prices for natural gas sales declined significantly to an average of $1.96 in 1986 from $2.36 in 1985. Decreased export sales during the first part of the year reduced the export flow back, thus dropping prices. Deregulation on November 1, 1986 caused them to reduce further.

Approximately 45% of the Company's crude oil from operated properties is being sold through Canpet Marketing Ltd., 30% to Mobil Oil Canada Ltd., 20% to Murphy Oil Canada Ltd. and 5% to others. Crude oil prices fell dramatically during the year before rebounding slightly at year end. The Company received an average price of $18.68 for its oil in 1986, down from the 1985 average of $35.46.

Revenue Net Backs

	Years ended December 31			
	Oil		Gas	
	1986	1985	**1986**	1985
	($/bbl)		($/mcf)	
Revenue	**$18.68**	$35.46	**$1.96**	$2.36
Royalties	**2.75**	7.32	**.42**	.46
Operating costs	**4.31**	6.00	**.34**	.36
	$11.62	$22.14	**$1.20**	$1.54

Major Areas of Activity

In 1986, NCO's development and exploration activities were centered in Saskatchewan and Alberta.

Saskatchewan

A significant portion of the Company's oil and gas reserves are in Saskatchewan. Currently, some 30% of its natural gas production and 40% of its oil production is from this province. In addition, 41% of the Company's natural gas reserves and 26% of its oil reserves are in Saskatchewan.

Gas is produced from over 500 wells in the Hatton field, located in the southwest corner of the province. Gas production averaged 39 mmcfd in 1986 and is sold to the Saskatchewan Power Corporation.

Oil production in the province totalled 914 bopd. The majority of this oil was produced from 97 wells in the Dodsland/Plato field and 18 wells at Manito Lake, all located in southwestern Saskatchewan.

NCO participated in the drilling of 16 exploratory wells in the province resulting in eight gas and three oil discoveries. All of the drilling was in southwestern Saskatchewan, primarily in the Hatton/Maple Creek, Plato/Dodsland, Fort Pitt and Fairmont areas. In addition, 53 development wells were drilled resulting in two gas wells in Hatton/Maple Creek and 47 oil wells in the Plato/Dodsland area. Approximately 300 miles of seismic data was acquired in the Tablelands and Makwa areas. The Company purchased 29,565 net acres of land at an average price of $36 per acre during the year.

Alberta

Alberta continued as the main focus of NCO's activity. Currently, 70% of its natural gas production and 60% of its oil production is from Alberta. The province also accounts for 58% and 73% of the Company's natural gas and oil reserves respectively.

NCO had an active exploration program in Alberta throughout 1986. The Company participated in the drilling of 60 exploratory wells which resulted in 13 gas wells and 23 oil wells. In addition, 1,620 miles of new seismic data was acquired. An average price of $38/acre was paid for 104,847 net acres of prospective Crown land during the year.

Southern Alberta

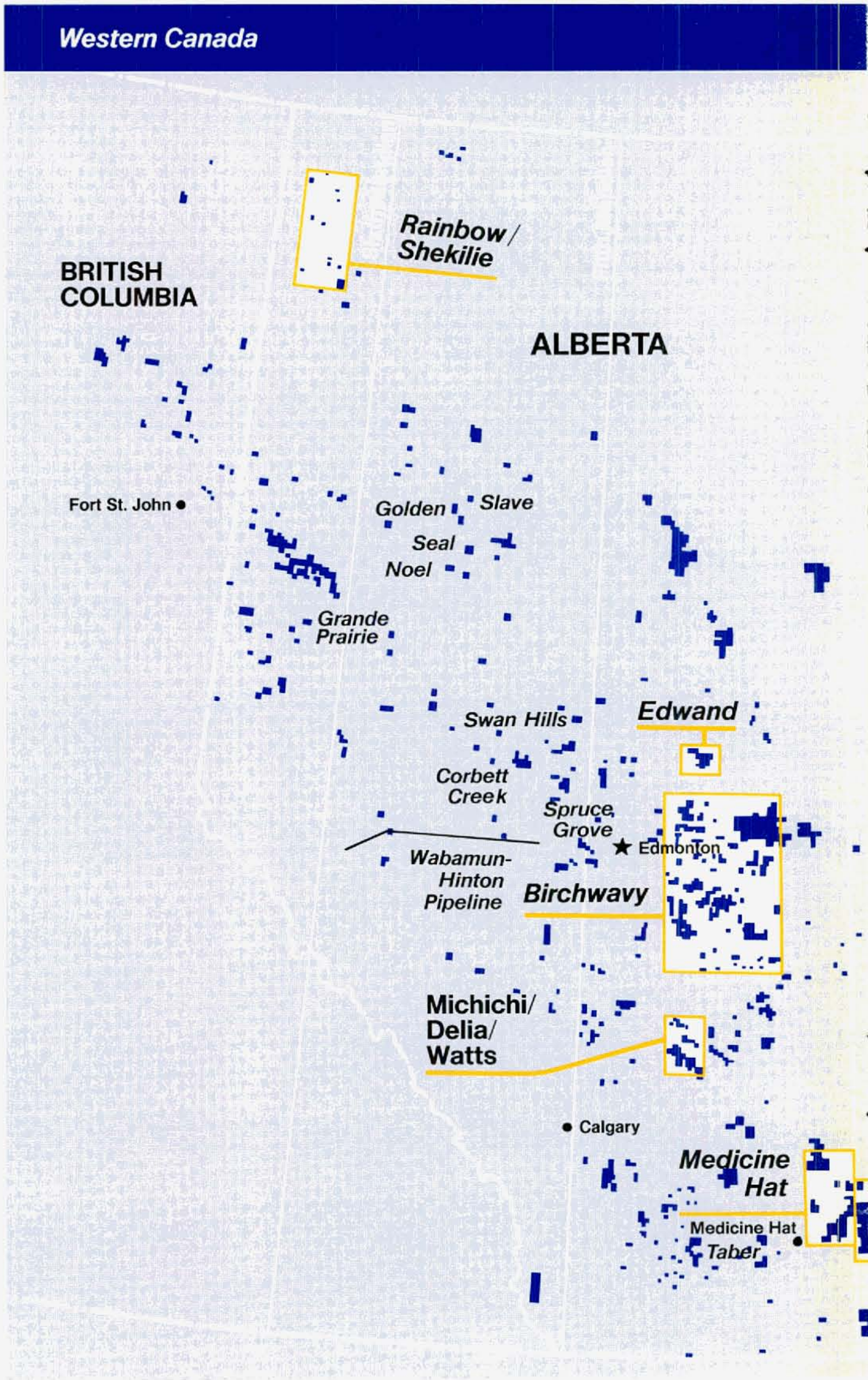
In the Medicine Hat area in southeastern Alberta, the Company has an interest in over 1,300 wells producing to 10 processing plants. NCO's share of production averaged 33 mmcfd in 1986. This gas, 95% operated, is contracted to TransCanada PipeLines Limited and SPC.

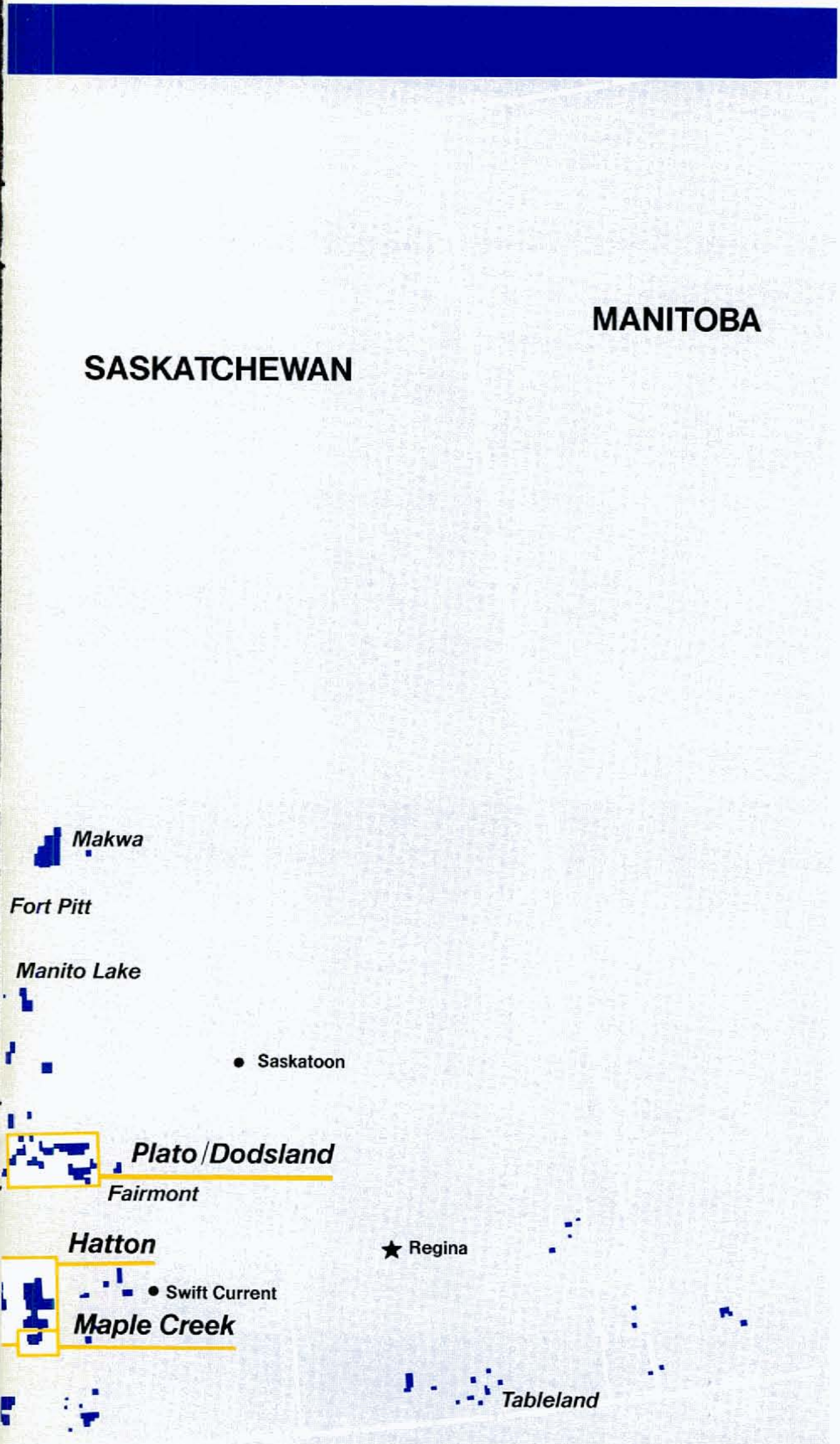
At Taber daily oil production was 255 barrels and is produced from an established field of 43 operated oil wells.

Exploration activity was centered in the Michichi/Delia/Watts area. The Company acquired 230 miles of new seismic data and 6,000 acres of Crown land. In addition, 14 exploratory wells were drilled resulting in six oil and two gas discoveries.

Central Alberta

The Birchwavy area of east central Alberta continues to be the Company's largest gas producing area. The Company has a 70% working interest in 650 wells and 18 gas processing plants. In 1986, NCO





produced over 40 mmcfd of natural gas from this area to its TCPL contract and drilled 26 development wells, resulting in 20 successful gas wells.

Forty-five thousand net acres of highly prospective land were purchased in the Birchwavy contract area with an additional 19,000 acres acquired in the Swan Hills, Spruce Grove and Corbett Creek areas. Approximately 320 miles of new seismic data was analyzed to aid in evaluating land purchases and assist in locating the 26 well development drilling program.

Northern Alberta

The Company added approximately 1,200,000 bbls of proven oil reserves in the Rainbow/Shekilie area in 1986. Because of the seasonal accessibility of the area and limited facilities, 1986 production averaged only 206 bopd. It is projected that this area will average at least 500 bopd in 1987.

More than 50 percent of the Company's1986 exploration expenditures were dedicated to Northern Alberta. At Edwand, in northeastern Alberta, 4,500 acres of land were acquired and six exploratory wells were drilled. This drilling resulted in five gas discoveries. Two oil wells, one at Seal and one at Noel, were drilled in northwestern Alberta and 27,000 net acres were acquired in the Golden, Slave and Grande Prairie areas.

In the Rainbow/Shekilie Devonian reef basins located in the northwestern corner of the province, the Company conducted an extensive and very successful exploration program. Seismic data totalling 800 miles was acquired and 13 exploratory wells were drilled resulting in eleven cased oil discoveries. In addition, 6,100 acres of Crown land were purchased during the year at an average price of $172 per acre. Four exploratory tests spudded just prior to year end were subsequently completed as oil wells in early 1987.

Production

Natural gas production averaged 130.6 mmcfd in 1986, down marginally from the 1985 level of 133.2 mmcfd. Reduced contract rates of take by the Company's major purchasers were primarily responsible for the decline, however, this was substantially offset by increased direct sales to Alberta industrial consumers.

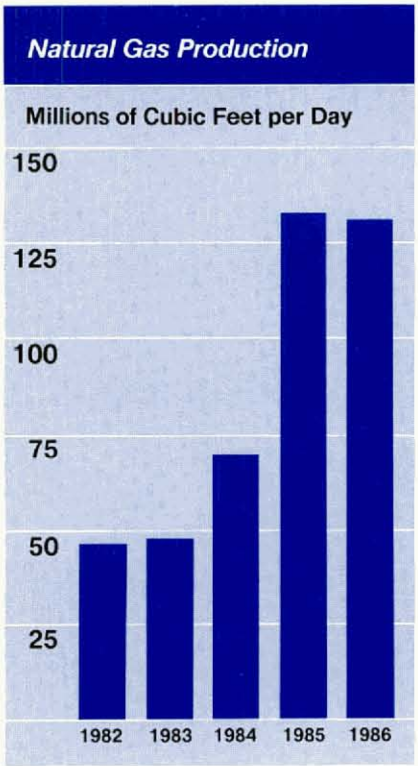
Oil and natural gas liquids production continued its growth, increasing to 2,302 bopd from 2,050 bopd in 1985. Continued development in the Plato/Dodsland area of southwestern Saskatchewan and the Rainbow/Shekelie area of northern Alberta, more than offset production declines in the mature areas such as Taber in southern Alberta and Joarcam in east central Alberta.

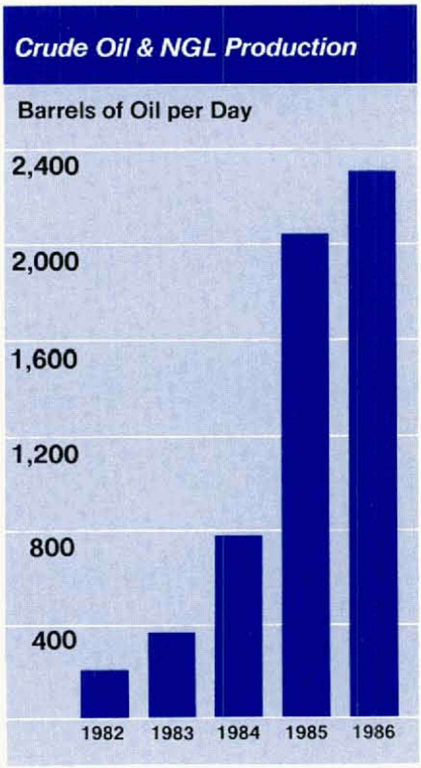
Natural Gas Production

	Years ended December 31			
	1986		1985	
	mmcfd	%	mmcfd	%
East Central Alberta	**41.6**	**32**	31.3	24
Saskatchewan	**39.0**	**30**	40.5	30
Southeast Alberta	**33.3**	**26**	37.5	28
Southern Alberta	**12.2**	**9**	18.3	14
Northern Alberta	**4.5**	**3**	5.6	4
	130.6	**100**	133.2	100

Oil and Natural Gas Liquids Production

	Years ended December 31			
	1986		1985	
	bopd	%	bopd	%
Saskatchewan	**914**	**40**	631	31
Southern Alberta	**622**	**27**	606	30
Northern Alberta	**497**	**21**	463	22
East Central Alberta	**269**	**12**	350	17
	2,302	**100**	2,050	100





Finding Costs

NCO's average finding cost continued to be very favourable relative to industry averages. A review of Western Canadian expenditures and reserves data reported by the Canadian Petroleum Association indicates an industry average finding cost, calculated on the same basis, of $6.44 per barrel in 1985 whereas NCO's finding costs for proved developed reserve additions were only $4.44 per barrel in 1986.

Finding Costs

	Years ended December 31			
	1986		1985	
Proved developed reserves added *(mbbls)	**4,372**		9,637	
	$000	$/bbl	$000	$/bbl
Drill and complete	**11,000**	**2.52**	19,400	2.01
Land	**5,000**	**1.14**	11,300	1.17
Seismic	**3,400**	**.78**	4,700	0.49
	19,400	**4.44**	35,400	3.67

*Gas converted to oil equivalent using 10 thousand cubic feet (mcf) per barrel.

Proved and Probable Reserves

	Natural Gas (bcf)			Crude Oil and NGL (mbbls)		
	Proved	Probable	Total	Proved	Probable	Total
Reserves at 1/1/86	784	130	914	5,329	1,269	6,598
Reserves added	23	–	23	1,862	–	1,862
Improved recovery	1	–	1	181	–	181
Reserves produced	(48)	–	(48)	(840)	–	(840)
Revisions to previous estimates	–	(2)	(2)	(54)	(143)	(197)
Reserves at 12/31/86	760	128	888	6,478	1,126	7,604

Reserves and Values

Proven gas reserves added during the year, totalled 23 bcf or 48% of production, with more than half discovered in the Birchwavy area of east central Alberta. Because of the reduced takes by the major purchasers of natural gas in Alberta and the lack of new gas markets, the emphasis of the 1986 program was on oil prospects. The Company, however, continues to hold a large portfolio of prospective lands for natural gas. These will be developed as markets become available.

Drilling of oil prospects resulted in the addition of some 1.9 million barrels of proven oil, or 222% of yearly production, the majority of which came from Rainbow/Shekilie area of northern Alberta and Plato/Dodsland area in southwest Saskatchewan.

Reserve Values

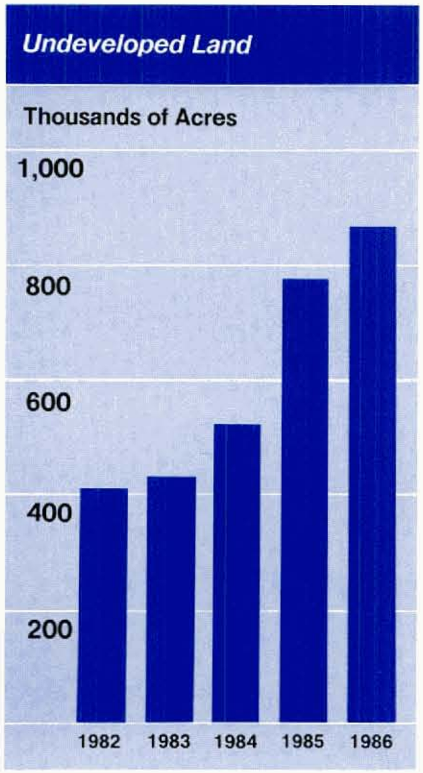
The estimated present value of NCO's proved and probable reserves, as determined by an independent engineering consultant, are outlined in the accompanying table. These values represent the forecast of income derived from the production and sale of net reserves, less capital expenditures, wellhead taxes and operating costs, but before the deduction of interest, income tax or other corporate costs. Average oil and natural gas prices used for the next five years are outlined below with real price increases, above a 6% inflation factor, averaging 1% and 1.3% respectively, from 1992 onward.

Price Forecast

	Oil ($/bbl)	Natural Gas ($/mcf)
1987	22.89	1.79
1988	24.16	1.86
1989	25.42	2.12
1990	27.20	2.45
1991	29.09	2.65

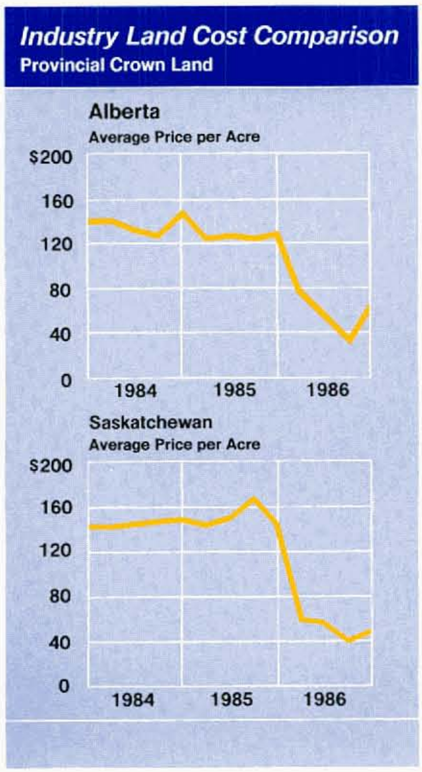
Reserve Values ($000)

	Undiscounted	10% Discount	15% Discount
Proved	$1,675,213	$683,956	$510,588
Probable	325,267	79,256	47,620
	2,000,480	763,212	558,208
Tax credits	106,599	39,371	28,875
Total	**$2,107,079**	**$802,583**	**$587,083**



Land Position

During 1986, NCO acquired 226,097 gross acres (137,550 net acres), the majority of which was purchased at Crown land sales at a cost of $5.3 million. Average prices paid were $38 per acre in Alberta and $36 per acre in Saskatchewan, down from $74 and $67 per acre respectively for land acquired in 1985. Much of this acreage was purchased in prime exploration and development areas, backed by seismic information. The depressed economic environment in 1986 provided the Company with an opportunity to build a quality land portfolio at a relatively low cost.



Land — Land Holdings as at December 31, 1986

	Developed Acres* Gross	Developed Acres* Net	Undeveloped Acres Gross	Undeveloped Acres Net
British Columbia	6,556	1,617	88,749	17,930
Alberta	1,597,517	646,764	1,418,843	528,141
Saskatchewan	297,145	196,878	627,686	311,980
Manitoba	160	—	10,710	5,035
	1,901,378	**845,259**	**2,145,988**	**863,086**

*Developed acres are those defined by the drilling spacing unit or as designated so by the Crown.

Drilling

The Company participated in the drilling of 192 gross (79.4 net) wells during 1986 compared to 286 gross (153 net) during 1985. Exploration and development expenditures totalled $18.9 million, while seismic costs totalled $3.7 million. Government grants reduced these expenditures by $5.8 million. The Company continued its policy of assuming the role of operator wherever possible, drilling 34 gross (18.9 net) of the exploration wells and 65 gross (41.2 net) of the development wells.

Exploratory Drilling

	Years ended December 31			
	1986		1985	
	Gross	Net	Gross	Net
Oil wells	**25**	**6.8**	36	12.3
Gas wells	**22**	**10.4**	43	17.3
Dry and abandoned	**30**	**8.3**	31	11.9
	77	**25.5**	110	41.5
Success ratio		**67%**		71%

Development Drilling

	Years ended December 31			
	1986		1985	
	Gross	Net	Gross	Net
Oil wells	**60**	**33.1**	87	46.1
Gas wells	**38**	**14.9**	76	61.1
Dry and abandoned	**17**	**5.9**	13	4.3
	115	**53.9**	176	111.5
Success ratio		**89%**		96%

Pipeline

NCO owns and operates a 136 mile, 10" diameter, intraprovincial natural gas transmission line and several miles of connecting laterals in the Wabamun-Hinton area of west central Alberta. The two major customers of the line are a pulp mill in Hinton and a local distributing company. The contract with the pulp mill calls for up to 24 mmcfd to April 30, 1997. During 1986, the Company averaged 27.5 mmcfd (10.0 bcf for the year) through the line, a 10% increase over the 1985 figure of 24.9 mmcfd (9.1 bcf for the year).

NCO also owns and operates a 1.7 mile, 4" diameter line serving an industrial customer in the Balzac area north of Calgary, Alberta. During 1986, the Company averaged 3.7 mmcfd (1.4 bcf for the year) through this line, down slightly from 3.9 mmcfd in 1985.

Polaris Mine

NCO, through its subsidiary Bankeno Resources Limited, owns a 25% royalty interest in the total net proceeds from the Polaris Mine, a lead-zinc mine operated by Cominco Ltd. on Little Cornwallis Island in the Canadian Arctic. The Polaris Mine has operated continuously since startup in March 1982. The costs of developing the mine, the initial start up costs and the operating costs net of sales, together with interest incurred on those amounts, totalling approximately $252,000,000, must be recouped before the Company receives any payment.

Financial Review

Results of Operations 1986 and 1985

Revenue

The declining price of gas under deregulation, together with the reduction in world oil prices, resulted in net oil and gas revenues decreasing to $90.8 million in 1986, from $117.9 million in 1985. In 1986, net gas revenue decreased to $73.4 million on sales of 130.6 mmcf/d, as compared to $92.9 million on only slightly higher sales of 133.2 mmcf/d. This change reflected a price decrease of 17%, to an average of $1.96 from $2.36 in 1985. Despite an increase in oil production in 1986 to 2,302 bopd from 2,050 bopd in 1985, a decrease in average prices to $18.68 from $35.46 resulted in net oil revenues decreasing in 1986 to $13.4 million from $21.1 million. The Company's pipeline operation and gas marketing contribution increased marginally to $4.0 million in 1986 compared to $3.9 million in 1985.

The Company's investment portfolio contributed $21.4 million of revenue in 1986 as compared to $25.8 million in 1985. The decrease was a result of a reduction in the portfolio, the proceeds of which were used to reduce long-term debt obligations.

Expenses

As decreased revenues were primarily the result of decreased prices, similar decreases in costs were not possible. However, efforts to improve efficiencies in the Company's operations began to show positive results during 1986, as operating costs decreased 7% to $20.9 million in 1986 from $22.5 million in 1985.

The amalgamation of NCO with Merland during the year resulted in general and administrative costs decreasing by 15% to $7.4 million in 1986, from $8.7 million in 1985.

A $5 million saving in interest cost resulting from the conversion of the 8% convertible debentures was the primary cause of the 19% reduction in interest costs to $26.5 million in 1986 from $32.7 million in 1985. Reductions in long-term debt in late 1986 and early 1987, through sales of marketable securities, will further reduce interest expense in 1987. The net earnings available for payment of interest (before interest on long-term debt and deferred income taxes) were $48.5 million in 1986 and $66.2 million in 1985, which were 1.8 and 2.0 times the interest expense for those years respectively.

The decrease in earnings resulted in deferred income taxes decreasing to $5.2 million in 1986, from $10.5 million in 1985. The reduced revenue, combined with lower PGRT rates and the elimination of PGRT effective October 1, 1986, caused PGRT to also decrease by a substantial amount to $4.6 million from $11.8 million.

Earnings and Cash Flow

Net earnings for 1986 decreased to $16.8 million or $0.30 per common share, as compared to $23.0 million or $1.21 per common share in 1985 on a weighted average number of common shares outstanding of 11,885,321 and 10,821,739 respectively. These earnings were approximately 1.3 and 2.3 times the annual fixed dividend requirement for 1986 and 1985 respectively. After providing for the conversion of all dilutive instruments, earnings per share on a fully diluted basis was $0.30 in 1986, as compared to $1.10 in 1985, based on 11,885,321 and 17,481,559 common shares outstanding respectively. In 1986, none of the convertible issues were dilutive. Cash flow from operations was $60.2 million in 1986, compared to $72.0 million in 1985, as a result of the drop in oil and gas revenues.

Ceiling Test Reporting

The Company is subject to the regulations of the United States Securities and Exchange Commission, as NCO has a substantial number of United States shareholders. In the United States, generally accepted accounting principles ("GAAP") require oil and gas companies, on a quarterly basis, to compare the carrying cost of the Company's oil and gas assets, net of deferred income taxes, to the value, using a 10% discount rate, of the assets at existing prices and after the deduction of income tax ("U.S. Ceiling Test"). At December 31, 1986, the carrying cost of the assets on the balance sheet exceeded their value, as calculated using SEC rules, by approximately $26 million. The Company is also subject to ceiling test limitations under Canadian

GAAP which again compares the carrying cost of the Company's oil and gas assets, but to a different value. This value is also based on existing prices and costs, but is after estimates for future administrative, financing and income tax costs, but with no discounting. Under the Canadian ceiling test the value of the assets exceeds the carrying cost by more than $100 million.

Results of Operations 1985 and 1984

The Company's results of operations for 1985 include the results of Bankeno and Merland for the full year, while the 1984 results include Bankeno and Merland for only the last quarter of 1984.

Revenue

Natural gas and crude oil revenue (net of royalties) was $114 million compared to $57 million in 1984 and was mainly attributable to the inclusion of Bankeno and Merland for the full 1985 year. Revenue from natural gas increased to $92.9 million on sales of 133.2 mmcf/d in 1985, as compared to $47.9 million on sales of 72 mmcf/d in 1984. Crude oil and natural gas liquids revenue also increased in 1986 to $21.1 million on sales of 2,050 bopd, as compared to $9.1 million on sales of 808 bopd. While natural gas prices increased 6% to $2.36 in 1986 from $2.21 in 1985, oil prices declined 6% to $35.46 from $37.95. The Company's pipeline operation and gas marketing contribution increased to $3.9 million in 1985, from $3.0 million in 1984, due to increased marketing activities in Alberta.

Investment and other income rose $10.3 million to $25.8 million as a result of the increase in investments and the note receivable.

Expenses

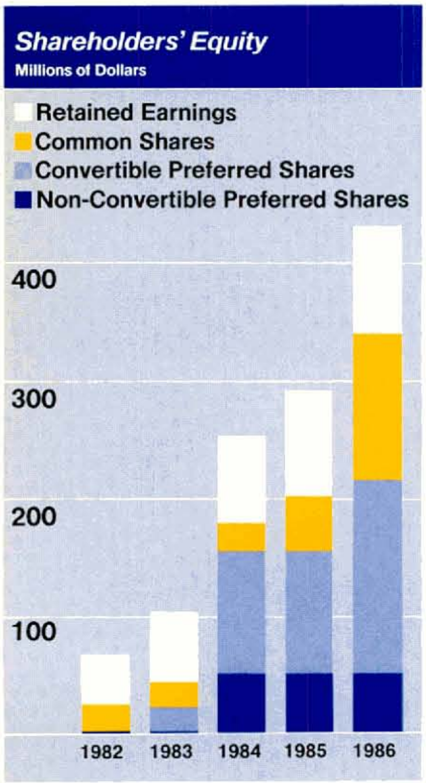
Operating expenses of $22.5 million, as compared to $10.3 million, increased as a result of additional wells coming on production, continuing maintenance programs and the inclusion of Bankeno and Merland for the full 1985 year. The increase in depreciation and depletion over 1984, resulted from an increase in the consolidated asset base, a downward revision of proven oil and gas reserves and an increase of future capital expenditure estimates.

Interest expense increased to $32.7 million due to the inclusion of Bankeno and Merland for the full 1985 year and increased long-term debt to finance the capital expenditure and investment programs.

Income and resource taxes amounted to $18.6 million, an increase of $8 million, which reflects the inclusion of Bankeno and Merland for the full 1985 year.

Earnings and Cash Flow

Net earnings for 1985 decreased to $23.0 million or $1.21 per common share, from $24.0 million or $2.26 per common share in 1984. The weighted average number of common shares outstanding were 10,821,739 and 8,646,548 respectively. After providing for all dilutive instruments, earnings per common share were $1.10 on 17,481,559 common shares in 1985, versus $1.59 on 14,275,929 common shares in 1984. The decrease in net earnings was primarily the result of increased depreciation expense, as cash flow from operations increased 72% to $72.0 million in 1985, compared to $41.8 million in 1984. This increase was primarily the result of the inclusion of Bankeno and Merland for a full year.



Liquidity and Financial Resources

During 1986, several financing activities were undertaken which further strengthened NCO's financial position.

- $83.6 million was spent on purchasing the minority shareholders' interest in Merland through the issuance of $23.5 million in common shares and $60.1 million in preferred shares.
- $50 million of common shares were issued to retire the 8% convertible debentures.
- $11.5 million was received on the sale of our interest in a subsidiary company.
- $7.4 million of common shares were issued which enabled NCO to realize on investment tax credits that otherwise would be lost.
- $39 million of marketable investments were sold in 1986 and a further $50 million were sold in 1987, with the proceeds from both sales reducing long-term debt.

These initiatives resulted in financial resources as at the end of 1986 which include:

- $55 million of marketable investments after all debt is repaid;
- $434 million of shareholders' equity, consisting of $218 million attributable to common shareholders and $216 million to preferred shareholders;
- Virtually all of NCO's property and equipment is unencumbered by debt;
- Substantial cash flow from operations to provide for future asset growth.

Securities Portfolio

NCO's portfolio of marketable investments was established through surplus funds from debt and equity issues. It consists of preferred and common shares of companies with large market capitalizations and provides a consistently high yield. The portfolio is maintained pending utilization of the funds for long-term investments in the oil and gas business. At December 31, 1986, the portfolio totalled $274 million, consisting of $209 million of marketable securities and $65 million in a secured note from the American Express Company. As a result of sales in January, 1987, the marketable securities portfolio was reduced to $159 million.

Price Range of Common Stock

	Toronto Stock Exchange Selling Price (Cdn.)		American Stock Exchange Selling Price (U.S.)	
	High	Low	High	Low
1986				
First Quarter	**$14.50**	**$10.75**	**$10.38**	**$ 7.50**
Second Quarter	**12.00**	**9.38**	**9.00**	**7.13**
Third Quarter	**10.50**	**9.38**	**7.75**	**6.63**
Fourth Quarter	**11.25**	**10.00**	**8.25**	**7.25**
1985*				
First Quarter	$15.11	$12.38	$11.00	$ 9.42
Second Quarter	15.50	12.67	11.50	9.50
Third Quarter	14.33	13.33	11.17	7.08
Fourth Quarter	14.88	13.00	10.75	9.38

*Adjusted for 3:2 stock split effective August 8, 1985.

At February 23, 1987 there were 6,546 common shareholders.

Long-term Debt Issue	Amount ($000)
10% debentures which bear interest at floating rates based on bankers acceptances with 10% cap are unsecured and mature in September, 1994	$ 70,143
Revolving bank indebtedness bearing interest at floating rates based on the bank prime rate or bankers acceptances	130,930
Income debentures which bear interest at one-half of the bank prime rate plus 1⅛%	3,708
Other loans and debentures	6,563
	$211,344

While natural gas and oil price reductions resulted in a decline in 1986 operating results, cash flow from operations will remain strong in 1987 and in the future. The Company had an active exploration and development program in 1986 which will continue into 1987, gaining momentum as natural gas volumes improve. NCO's strong financial base will provide the resources for oil and gas acquisitions as appropriate opportunities are identified.

Long-term Debt

The Company's debt obligations at December 31, 1986, totalled $220 million, of which $211 million was considered long-term. The debt is generally unsecured and except for $13 million in debentures, there are no fixed repayment requirements. The $50 million received in January, 1987, on the sale of marketable securities, went to further reduce the Company's revolving bank indebtedness.

Consolidated Balance Sheet
(thousands of Canadian dollars)

Assets

	December 31 1986	1985
Current assets		
Investments	**$209,337**	$248,397
Accounts receivable	**33,591**	33,841
Prepaid expenses	**1,102**	560
	244,030	282,798
Note receivable (Note 3)	**65,000**	65,000
Property and equipment ("Full cost" Notes 1 and 4)	**445,890**	446,573
Other assets, at cost	**5,599**	4,187
	$760,519	$798,558

Liabilities and Shareholders' Equity

	1986	1985
Current liabilities		
Accounts payable	**$ 32,444**	$ 32,929
Current portion of deferred revenue	**3,121**	2,912
Current portion of long-term debt	**8,333**	6,949
	43,898	42,790
Deferred revenue (Note 5)	**20,931**	24,506
Long-term debt (Note 6)		
Loans from affiliates	**—**	23,000
Other	**211,344**	304,622
	211,344	327,622
Deferred income and resource taxes	**44,455**	43,516
Minority interest (Note 8)	**6,258**	69,207
Shareholders' equity		
Share capital (Note 9)		
Preferred	**215,637**	155,540
Common shares 18,434,217 (1985—10,821,739)	**123,912**	44,895
Contributed surplus	**—**	140
Retained earnings	**94,084**	90,342
	433,633	290,917
	$760,519	$798,558

On behalf of the Board:

Director

Director

Consolidated Statement of Earnings
(thousands of Canadian dollars)

	Years ended December 31		
	1986	1985	1984
Revenue			
Gas and oil, net	**$ 90,808**	$117,928	$59,932
Investment and other income	**21,352**	25,820	15,477
	112,160	143,748	75,409
Expenses			
Operating	**20,854**	22,514	10,259
Administrative	**7,395**	8,664	4,719
Interest on long-term debt	**26,487**	32,708	15,721
Depreciation and depletion	**33,283**	34,037	9,677
	88,019	97,923	40,376
Earnings before taxes	**24,141**	45,825	35,033
Income and resource taxes			
Deferred (Note 7)	**5,161**	10,522	6,869
Petroleum and Gas Revenue Tax	**4,580**	11,816	5,983
Alberta Royalty Tax Credit	**(4,633)**	(3,721)	(2,271)
	5,108	18,617	10,581
Earnings before minority interest	**19,033**	27,208	24,452
Minority interest	**2,208**	4,242	442
Net earnings	**16,825**	22,966	24,010
Dividends on preferred shares	**13,224**	9,881	4,458
Net earnings attributable to common shares	**$ 3,601**	$ 13,085	$19,552
Earnings per common share			
Basic	**$ 0.30**	$ 1.21	$ 2.26
Fully diluted	**$ 0.30**	$ 1.10	$ 1.59

Consolidated Statement of Changes in Financial Position

(thousands of Canadian dollars)

	Years ended December 31		
	1986	1985	1984
Operating activities			
Net earnings from operations	**$ 16,825**	$ 22,966	$ 24,010
Non-cash items:			
Minority interest	**2,208**	4,242	442
Deferred income and resource taxes	**8,551**	11,700	6,761
Depletion and depreciation	**33,283**	34,037	9,677
Other	**(635)**	(986)	863
Cash generated from operations	**60,232**	71,959	41,753
Financing activities			
Issue of common shares	**79,017**	22,766	—
Issue of preferred shares	**60,104**	12,341	134,766
Increase in long-term debt	**404**	138,888	70,143
Repayment of long-term debt	**(93,682)**	(28,653)	(57,461)
Change in long-term debt with affiliates	**(23,000)**	(37,000)	60,000
Decrease in deferred revenue	**(3,575)**	(3,219)	(1,241)
Increase in notes receivable	**—**	(65,000)	—
Dividends paid on preferred shares	**(13,224)**	(9,881)	(4,458)
Dividends paid by subsidiary	**(1,839)**	(3,126)	—
Other	**256**	(22)	(258)
Cash generated from financing activities	**4,461**	27,094	201,491
Investing activities			
Purchase of minority's interest in subsidiary (Note 2)	**(83,598)**	—	—
Purchase of Bankeno Mines Limited	**—**	—	(158,689)
Sale of investment in subsidiary	**11,500**	13,888	—
Expenditure for property and equipment	**(31,812)**	(51,474)	(39,499)
Changes in other current accounts (Note 14)	**816**	(1,844)	7,772
Other	**(659)**	—	—
Cash utilized in investing activities	**(103,753)**	(39,430)	(190,416)
(Decrease) increase in investments	**(39,060)**	59,623	52,828
Investments, beginning of year	**248,397**	188,774	135,946
Investments, end of year	**$209,337**	$248,397	$188,774

Consolidated Statement of Retained Earnings
(thousands of Canadian dollars)

	Years ended December 31		
	1986	1985	1984
Balance at beginning of year	**$ 90,342**	$ 77,257	$57,705
Net earnings	**16,825**	22,966	24,010
Transfer from contributed surplus	**141**	—	—
	107,308	100,223	81,715
Deduct			
Dividends on preferred shares	**13,224**	9,881	4,458
Balance at end of year	**$ 94,084**	$ 90,342	$77,257

Report of Independent Chartered Accountants

The Shareholders
North Canadian Oils Limited

We have examined the consolidated balance sheets of North Canadian Oils Limited as at December 31, 1986 and 1985 and the related consolidated statements of earnings, retained earnings and changes in financial position for each of the three years in the period ended December 31, 1986. 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, these consolidated financal statements present fairly the financial position of the Company as at December 31, 1986 and 1985 and the results of its operations and the changes in its financial position for each of the three years in the period ended December 31, 1986 in accordance with generally accepted accounting principles in Canada applied on a consistent basis.

Calgary, Canada
February 16, 1987

Touche Ross & Co.
Chartered Accountants

Comment on Differences in Canadian-United States Reporting Standards

In the United States, reporting standards require reference in the auditors' report when reliance is being placed on the reports of other auditors who have examined financial statements of subsidiary companies. For 1984, 48.4% of total assets and 0.3% of net earnings were reported on by other auditors. The auditors' report above is expressed in accordance with Canadian standards which do not require such reference when appropriate communication has been made with the other auditors.

Calgary, Canada
February 16, 1987

Touche Ross & Co.
Chartered Accountants

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

These consolidated financial statements of the Company are stated in Canadian dollars and have been prepared in accordance with accounting principles generally accepted in Canada which are in accordance with generally accepted accounting principles in the United States, except as set out in Note 11.

Principles of Consolidation

The consolidated financial statements include the accounts of North Canadian Oils Limited, its wholly owned subsidiary companies and, its 86.6% (1985—86.6%; 1984—96.6%) interest in Bankeno Resources Limited ("Bankeno"). Effective July 1, 1986 the Company amalgamated with Merland Explorations Limited ("Merland"), a 53% owned subsidiary of Bankeno. As a result, the financial statements include Bankeno's interest in Merland to June 30, 1986 and 100% thereafter (Note 2).

Operations of the Company

The Company is principally engaged in the exploration, development and production of oil and natural gas with all significant assets and operations located in Canada.

Substantially all of the Company's oil and gas activities are carried out jointly with others and these financial statements reflect only the Company's proportionate interest in such operations.

Oil and Gas Operations

The Company follows the full cost method of accounting for oil and natural gas properties and related expenditures, whereby all costs related to the exploration for and development of oil and gas reserves are capitalized in country by country cost centres. Such costs include those related to lease acquisitions, geological and geophysical activities, lease rentals on non-producing properties and drilling of productive and non-productive wells. Proceeds from disposal of properties are normally deducted from the full cost pool without recognition of gain or loss.

Depletion of oil and gas properties and depreciation of production equipment and facilities are calculated using the unit-of-production method based upon estimated proven reserves, before royalties, converted to a common unit of measure using relative energy content.

The Company applies a ceiling test to capitalized costs to ensure that such costs do not exceed estimated future net revenues from production of proven reserves at year-end market prices less future administrative, financing and income tax costs.

Pipeline assets are depreciated on a straight-line basis over the term of the existing natural gas contracts. Other equipment is depreciated on a declining balance basis over the estimated useful lives of the assets at rates varying from 5% to 30%.

Mining

The Company holds a 25% royalty interest in a mine, the cost of which will be depleted when royalty revenue commences.

Investments

Investments, the majority of which have no quoted market values, are stated at the lower of cost and estimated net realizable value.

Income Taxes

The Company follows the tax allocation method of accounting under which the income tax provision is based on the earnings reported in the accounts. Under this method the Company provides for deferred income taxes to the extent that income taxes otherwise payable are eliminated by claiming capital cost allowance and exploration and development costs in excess of the depreciation and depletion provisions recorded in the accounts. Investment tax credits are deducted from the related expenditures when the benefit is realized.

Earnings Per Common Share

Basic earnings per common share is computed by dividing net earnings attributable to common shares by the weighted average number of common shares outstanding (1986—11,885,321; 1985—10,821,739; 1984—8,646,548). Fully diluted earnings per common share has been computed as above assuming the conversion of all dilutive securities effective the date of issue (weighted average number of common shares—1986—11,885,321; 1985—17,481,559; 1984—14,275,929).

2. Acquisitions

a) Effective September 28, 1984, pursuant to a purchase agreement and a related offer to minority shareholders, the Company purchased 96.6% of the common shares and 91.2% of the share purchase warrants of Bankeno. In 1985 the investment was reduced by 10%. The excess of the purchase cost over the related net book value of assets acquired was allocated to property and equipment and is being amortized over the life of such assets. As part of the purchase, working capital deficiency of $23,387,000 was acquired. The acquisition has been accounted for as a purchase as follows:

	1984 (in thousands)
Net assets acquired:	
Assets	$289,488
Liabilities	204,856
	$ 84,632
Consideration:	
10% debentures and cash	$ 70,536
Class B Preferred shares, Series 3	64,766
	$135,302

If Bankeno had been consolidated at January 1, 1984, the pro forma revenue, earnings and earnings per common share, both basic and fully diluted, for the year ended December 31, 1984 would have been $130,570,000, $25,882,000, $2.01 and $1.61, respectively.

b) Effective July 1, 1986, pursuant to an amalgamation agreement between the shareholders of the Company and Merland, the Company purchased the minority shareholders' interest in Merland. The difference between the purchase cost and the related minority interest acquired was allocated to property and equipment and is being amortized over the life of such assets. The acquisition has been accounted for as a purchase as follows:

	1986 (in thousands)
Net assets acquired	$ 85,204
Consideration:	
Common shares	$ 23,494
Class B Preferred shares	
Series 6	32,595
Series 7	27,509
	$ 83,598

The following pro forma information has been prepared as if the acquisition was effective January 1, 1985.

	Years ended 1986	1985
	(in thousands except per share data)	
Revenue	$112,160	$143,748
Net earnings	$ 18,243	$ 28,009
Income per common share		
Basic	$ 0.25	$ 1.11
Fully diluted	$ 0.25	$ 1.04

3. Note Receivable

The note receivable from a major corporation bears interest at prime rate, is secured by a pledge of certain marketable securities and is due no later than January 9, 1995.

4. Property and Equipment

	1986	1985
	(in thousands)	
Oil and gas properties and production equipment	**$486,320**	$456,509
Pipeline and other	**12,681**	10,467
Mining—royalty interest	**43,370**	43,013
	542,371	509,989
Less accumulated depreciation and depletion	**96,481**	63,416
	$445,890	$446,573

Grants under petroleum incentive programs aggregating $5,765,000 in 1986 and $7,728,000 in 1985 have been accrued in accordance with the regulations and treated as a reduction of the cost of related oil and gas exploration and development expenditures.

5. Deferred Revenue

Pursuant to take-or-pay provisions included in certain natural gas purchase contracts, payments were received by the Company in respect of annual contract gas volumes not taken by the purchaser. In November, 1984 the purchaser began to take delivery of the gas and the Company has recognized revenue related to the gas taken. The purchaser's present delivery schedule for the gas will allow recognition after 1987 of $20,931,000 of revenue over seven years with $3,187,000 in 1988, $3,400,000 annually in 1989 through 1993 and $744,000 in 1994.

6. Long-term Debt

	1986	1985
	(in thousands)	
11¼% sinking fund debentures	**$ 2,690**	$ 2,938
Income debentures	**11,124**	17,869
10% debentures	**70,143**	70,143
8% convertible debentures	**—**	50,000
Bank indebtedness	**130,930**	166,235
Loans from affiliates	**—**	23,000
Mining loan	**4,790**	4,386
	219,677	334,571
Less current portion	**8,333**	6,949
	$211,344	$327,622

The 11¼% sinking fund debentures and the income debentures are secured by certain of the Company's oil and gas properties. The sinking fund debentures are redeemable at 101.25% of the principal amount to August 31, 1988 and the Company is required to make sinking fund payments sufficient to retire $917,000 principal amount of debentures in 1987 and $1,773,000 in 1988. The income debentures are due June 1988 and bear interest at one half of the bank's prime lending rate plus 1⅛% and are repayable as follows: 1987—$7,416,000; 1988—$3,708,000.

The 10% debentures are unsecured and are due September 28, 1994 without current principal repayment requirements.

On December 11, 1986 the Company reached an agreement with the holders of the Company's $50,000,000 8% Convertible Debentures for conversion of the debentures into 5,000,000 common shares of the Company.

The mining loan bears interest at prime rate and no interest or principal payments are required until royalty revenue is received.

The Company has lines of credit from bankers and affiliates in the amount of $370,000,000 which when drawn down bear interest at prime rate and are repayable on demand. These lenders have agreed not to require repayment of the bank indebtedness or loans prior to December 31, 1987 and accordingly, the indebtedness and loans have been classified as long-term.

7. Deferred Income Taxes

The provision for deferred income tax differs from the result which would be obtained by applying the combined Canadian Federal and Provincial tax rate of 48.8% (1985—48%; 1984—48%) to earnings before taxes. The difference results from the following:

	1986	1985	1984
		(in thousands)	
Computed "expected" income tax	**$11,781**	$21,996	$16,816
Increase (decrease) in income taxes resulting from:			
Effect of subsidiaries and consolidation	**2,416**	1,161	—
Non-deductible crown payments	**6,965**	8,384	5,403
Federal resource allowance	**(8,797)**	(12,343)	(7,210)
Non-taxable Canadian dividends	**(8,259)**	(8,618)	(7,429)
Other	**1,055**	(58)	(711)
	$ 5,161	$10,522	$ 6,869

Deferred income taxes of $5,161,000 (1985 — $10,522,000; 1984 — $6,869,000) arose from the deduction of capital cost allowance, exploration and development expenditures and lease acquisition costs for tax purposes in excess of depreciation and depletion for accounting purposes.

8. Minority Interest

	1986	1985
	(in thousands)	
Preferred shares	**$ —**	$ 43,535
Common shares	**6,102**	31,706
Retained earnings	**156**	(6,034)
	$ 6,258	$ 69,207

Pursuant to the amalgamation effective July 1, 1986, Merland shares held by the minority shareholders were exchanged for Common and Class B preferred shares of the Company (Notes 2 and 9) effectively reducing the minority interest.

9. *Share Capital*

Authorized

20,149	5½% cumulative redeemable sinking fund preferred shares, each share having a stated value of $50
Unlimited	Class A preferred shares issuable in series
Unlimited	Class B preferred shares issuable in series
Unlimited	Special non-voting shares each without nominal or par value
Unlimited	Common shares each without nominal or par value

Issued

	1986		1985	
	Shares	**Amount (in thousands)**	Shares	Amount (in thousands)
Preferred shares				
5½% cumulative redeemable	**15,556**	**$ 777**	15,686	$ 784
Class A, Series 1	**2,000,000**	**50,000**	2,000,000	50,000
Class B, Series 1	**1,000,000**	**20,000**	1,000,000	20,000
Class B, Series 2	**800,000**	**20,000**	800,000	20,000
Class B, Series 3	**2,158,545**	**64,756**	2,158,545	64,756
Class B, Series 6	**1,303,788**	**32,595**	—	—
Class B, Series 7	**1,100,355**	**27,509**	—	—
		$215,637		$155,540
Common shares	**18,434,217**	**$126,199**	10,821,739	$ 46,026
Less: Notes Receivable (Note 10)		**2,287**		1,131
		$123,912		$ 44,895

Class A Preferred

The Class A preferred shares, Series 1 rank junior to the 5½% cumulative redeemable preferred shares with respect to all rights, privileges, restrictions and other conditions attaching to the preferred shares and holders of these shares are entitled to dividends, when declared, at the semi-annual rate of 70% of the floating bank prime rate per share. These shares are redeemable by the Company under certain conditions after June 30, 1989 and prior to June 30, 1993.

Class B Preferred

The Class B preferred shares, Series 1 to 7 rank junior to the 5½% cumulative redeemable preferred shares and the Class A preferred shares, with respect to all rights, privileges, restrictions and other conditions attaching to the preferred shares. The Series 1 shares are convertible at $13.33 per share into one common share prior to April 1, 1993, the Series 2 shares are convertible at $16.67 per share into one common share prior to September 2, 1993, the Series 3 shares are convertible at $20.00 per share into one common share prior to September 28, 1989, the Series 6 are convertible at $73.53 per share into one common share prior to December 31, 1990 and the Series 7 are convertible at $27.47 per share into one common share prior to June 30, 1990. The Series 1, 2, 3, 6 and 7 shares earn cumulative dividends (Series 1 and 2 at the annual rate of one-half bank prime plus one percent, Series 3 at the annual rate of one-half bank prime and the Series 6 and Series 7 at 8% and 7.5% respectively) and are redeemable by the Company under certain conditions.

Effective July 1, 1986, pursuant to the amalgamation (Note 2), the Company issued 1,303,788 Class B Preferred shares Series 6 and 1,100,355 Class B Preferred shares Series 7.

The Series 4 and 5 shares were created only in connection with the exercise by the holders of the 8% Convertible Debentures of the right to convert such Debentures into such shares. Upon conversion, the debenture holders waived their right to interest up to December 31, 1986. As the debentures were converted directly into common shares of the Company, the purpose for which these preferred shares were created no longer exists and $5,000,000 of interest was waived (Note 6). It is the intention of the Company to eliminate the shares from the authorized capital.

During 1984, the Company issued 2,000,000 Class A preferred shares, Series 1 for $50,000,000 cash, 800,000 Class B preferred shares, Series 2 on conversion of 8% convertible debentures in the principal amount of $20,000,000 and 2,158,881 Class B preferred shares, Series 3 for $64,766,000 on acquisition of Bankeno (Note 2).

Common Shares Issued and Reserved

On July 1, 1986, pursuant to the amalgamation (Note 2), the Company issued 1,957,853 common shares of the Company in exchange for the shares held by the minority shareholders of Merland.

The Board of Directors approved on December 11, 1986 the conversion of the Company's $50,000,000 8% Convertible Debentures into 5,000,000 common shares of the Company (Note 6) effective December 31, 1986.

Effective December 30, 1986, the Board of Directors of the Company approved the issue of 568,875 common shares and the transfer of $1,850,000 of investment tax credits of the Company for an aggregate consideration of $7,400,000. Of this total, $5,688,750 was credited to share capital and $1,711,250 to Property and Equipment.

In addition, 140,000 common shares (1985—34,200; 1984—41,500) were issued and 58,350 common shares were cancelled and returned to treasury under the Company's share purchase plan (Note 10).

Effective August 8, 1985, the Board of Directors approved a sub-division of each issued and outstanding common share of the Company into one and one-half common shares. During 1985 2,141,010 common shares were issued on redemption of the floating rate convertible debentures and 5,040 shares were redeemed for cash by the Company for a total principal amount of $21,460,000.

At December 31, 1986 the Company has reserved for issue a total of 7,715,078 common shares under conversion rights of the issued preferred shares and outstanding stock options.

10. Other Information

Share Purchase Plan

The Company has a Management Share Purchase Plan whereby common shares may be purchased by the management of the Company. During 1986, 140,000 (1985—34,200) common shares were purchased under this plan. Notes receivable in respect of the shares purchased under this plan in the amount of $2,042,000 at December 31, 1986 (1985—$892,000) are due from officers and are shown as a reduction of common share capital.

Stock Option Plan

Effective April, 1986 the Company adopted the Employee Incentive Share Option Plan which is available to full-time employees of the Company. Shares totalling 332,650 have been reserved for issuance at market prices and under the terms of the agreements, each employee has the right to exercise 20% of the options yearly with cumulative rights to acquire in subsequent years shares not acquired during previous years. At December 31, 1986 stock options totalling 308,837 common shares are outstanding under this plan at prices ranging from $11 to $12.

Under a previous Employee Stock Option Plan which expired during 1983 notes receivable in respect of options exercised in the amount of $245,000 at December 31, 1986 (1985—$239,000) are shown as a reduction of common share capital.

Pension Plan

Effective July 1, 1986, the Company replaced its defined benefit plan with a defined contribution pension plan. The plan, which is available to all employees, is a voluntary contribution plan whereby employees' contributions up to 4% of base salary are matched by an equivalent contribution by the Company. Company contributions made under the plans totalled $136,000 in 1986 (1985 — $104,000; 1984 — $164,000). There are no unfunded liabilities under either of the plans at December 31, 1986.

Related Party Transactions

From time to time, the Company arranges investment transactions in conjunction with certain affiliates. These transactions are arranged without cost and at normal market terms. Dividends from investments in affiliates totalled $291,000 in 1986 (1985—$100,000; 1984—$Nil).

The Company also arranges financing transactions with affiliates at normal market terms. In 1986 the Company paid interest in the amount of $4,150,000 (1985—$7,281,000; 1984—$4,170,000) on loans from affiliated companies, $Nil (1985—$23,000,000) of which was outstanding at year-end. In addition, interest of $Nil (1985—$Nil; 1984—$1,164,000) on floating rate convertible debentures was paid to two shareholder companies. Dividends of $1,441,000 (1985—$1,248,000) were also paid to an affiliate on Class B preferred shares, Series 1.

The Company accrued professional fees aggregating $598,000, $237,000 and $295,000 to two legal firms in which certain directors of the Company are partners for the years ended December 31, 1986 to 1984 respectively.

Under the terms of certain profit sharing and incentive plans, certain employees of the Company receive royalty on production from some specified Company wells.

11. Reconciliation to Accounting Principles Generally Accepted in the United States

These financial statements have been prepared in accordance with accounting principles generally accepted in Canada. Under United States accounting principles, the calculation of the ceiling test under the full cost method requires the discounting of future net revenues from production of proved oil and gas reserves by 10%. In addition, deductions from net revenue for administrative and financing costs under the calculation are not permitted. Under FAS #84 the treatment of the conversion of the 8% debentures would result in common share capital being increased with a corresponding reduction of earnings and retained earnings.

The effect of the above differences between Canadian and United States accounting principles for the year ended December 31, 1986 would result in an additional depletion charge of $26,000,000 and an expense of $26,380,000 relating to the conversion of the 8% debentures. The net loss, the basic and fully diluted loss per share for the year, net book value of property and equipment, common share capital and retained earnings at December 31, 1986 would be $35,555,000, $4.11, $4.11, $419,890,000, $150,292,000 and $41,704,000 respectively.

12. Dependence Upon Limited Customers

Two customers to whom the Company sold natural gas and which individually accounted for more than 10% of gross revenue before investment income are as follows:

	Amounts		Percent of total revenue	
	1986	1985	1986	1985
	(in thousands)			
Company				
TransCanada PipeLines Limited	$51,972	$ 73,882	43	60
Saskatchewan Power Corporation	29,305	30,377	24	25
Total	$81,277	$104,259	67	85

13. Commitments and Contingencies

Commitments and contingencies exist under agreements and operations in the normal course of business, the total amount of which in the opinion of management would not be significant to the financial position of the Company.

14. Changes in Other Current Accounts

	Years ended December 31		
	1986	1985	1984
		(in thousands)	
Currents assets—(increase) decrease			
Accounts receivable	$ 250	$ 2,614	$(22,921)
Prepaid expense	(542)	(78)	(423)
	(292)	2,536	(23,344)
Current Liabilities—Increase (decrease)			
Accounts payable	(485)	(6,310)	23,565
Current portion of deferred revenue	209	100	2,812
Current portion of long-term debt	1,384	1,830	4,739
	1,108	(4,380)	31,116
Net change in other current accounts	$ 816	$(1,844)	$ 7,772

15. Comparative Figures

Certain of the comparative amounts have been reclassified to conform with current presentation.

16. Quarterly Financial Information (unaudited)

	Three months ended			
	Dec. 31	Sept. 30	June 30	March 31
	(in thousands)			
1986				
Net revenue	**$23,409**	**$21,060**	**$29,786**	**$37,905**
Net earnings (loss)	**$ 5,712**	**$ (878)**	**$ 5,613**	**$ 6,378**
Net earnings (loss) per common share after preferred share dividends				
Basic	**$ 0.20**	**$ (0.41)**	**$ 0.09**	**$ 0.42**
Fully diluted	**$ 0.20**	**$ (0.39)**	**$ 0.16**	**$ 0.33**
1985				
Net revenue	$37,591	$32,306	$36,285	$37,566
Net earnings	$ 182	$ 6,086	$ 7,931	$ 8,767
Net earnings (loss) per common share after preferred share dividends				
Basic	$ (0.26)	$ 0.40	$ 0.27	$ 0.80
Fully diluted	$ (0.09)	$ 0.31	$ 0.48	$ 0.40

Certain amounts are different than those reported in Form 10-Q as per Note 15.

The reduced net income in the fourth quarter of 1985 resulted from increased depletion and depreciation as a result of a re-evaluation of oil and gas reserves.

17. Disclosure of Oil and Gas Producing Activities as Required by Statement of Financial Accounting Standards No. 69

At December 31, 1986 and 1985 there were no significant capitalized costs relating to unproved oil and gas properties.

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

	1986	1985	1984
		(in thousands)	
Acquisition of properties	**$ 5,795**	$13,347	$ 8,459
Exploration	**$ 9,408**	$14,212	$ 5,873
Development	**$13,134**	$23,834	$23,580

Results of operations for producing activities ended December 31

	1986	1985	1984
		(in thousands)	
Revenue			
Sales (net)	**$86,835**	$113,980	$56,967
Production costs	**19,936**	21,770	9,775
Depreciation and depletion	**32,664**	33,312	9,320
	52,600	55,082	19,095
Income before taxes	**34,235**	58,898	37,872
Income and resource taxes	**16,998**	29,973	17,988
Results of operations from producing activities (excluding corporate overhead and interest costs)	**$17,237**	$ 28,925	$19,884

Estimated quantities of proved oil and gas reserves as at December 31 (unaudited)

	1986		1985		1984	
	Oil	**Gas**	Oil	Gas	Oil	Gas
Beginning of year	**5,329**	**784.3**	4,582	1,025.4	1,223	578.8
Revisions of previous estimates	**(54)**	**0.1**	(673)	(297.8)	24	—
Improved recovery	**181**	**0.7**	—	—	—	9.0
Purchase of minerals-in-place	**—**	**—**	—	—	3,396	464.0
Extensions and discoveries	**1,862**	**22.6**	2,167	105.0	215	—
Production	**(840)**	**(47.7)**	(747)	(48.3)	(276)	(26.4)
End of year	**6,478**	**760.0**	5,329	784.3	4,582	1,025.4

i) Oil is stated in thousands of barrels before royalty interests and gas is stated in billion cubic feet before royalty interests.

ii) The year end quantities are based on independent engineering reports.

iii) At December 31, 1986, 7 billion cubic feet of gas (1985—229; 1984—217) and 131 thousands of barrels of oil (1985—1,210; 1984—1,561) are attributable to minority interests in subsidiaries.

iv) At December 31, 1986, 187 billion cubic feet of gas and 340 thousands of barrels of oil of the total proved reserves are undeveloped.

v) There are no long-term supply agreements with foreign governments or any significant foreign geographic reserves.

vi) The year end reserve data includes 100% of the reserves of all subsidiaries. The 1985 revisions are the result of a re-evaluation of the quantity and recoverability of reserves based on studies of existing reserves.

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

	1986	1985	1984
		(in thousands)	
Future cash inflows	$1,240,657	$1,628,934	$1,930,901
Future production & development costs	440,975	443,170	606,596
Future income tax expenses	234,126	385,003	478,195
Future net cash flows	565,556	800,761	846,110
10% annual discount for estimated timing of cash flows	274,130	405,935	481,360
Standardized measure of discounted net cash flows	$ 291,426	$ 394,826	$ 364,750

i) Future net cash flows are after deducting royalties and were computed using year end prices and costs and year end statutory tax rates.

ii) At December 31, 1986 approximately $3,486,000 (1985—$118,000,000) of net cash flows are attributable to minority interests in subsidiaries.

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

	1986	1985	1984
		(in thousands)	
Sales and transfers of oil and gas produced, net of production costs	$ (66,952)	$ (91,466)	$ (47,193)
Net changes in prices and production costs	(193,445)	(42,982)	(36,253)
Purchase of minerals-in-place	—	—	477,049
Extensions, discoveries and improved recovery, less related costs	29,186	92,995	13,220
Development costs incurred during period	13,134	23,834	23,580
Net change in development costs	178	(25,839)	—
Revisions of previous quantity estimates	(5,224)	(153,012)	—
Accretion of discount	39,483	36,475	16,849
Net changes in income taxes	150,877	93,192	(176,723)
Other	(70,637)	96,879	(74,270)
	$ (103,400)	$ 30,076	$ 196,259

Amortization per equivalent physical unit of production (Mcf):

	1986	1985	1984
Depreciation and depletion	$ 0.62	$ 0.60	$ 0.33

Our Business Philosophy

North Canadian Oils Limited will conduct its business activities according to the highest standards of ethical behaviour and in keeping with the following basic principles:

- operations will be conducted in a cost effective manner and in the best interest of all shareholders with emphasis on total return comprising increases in underlying asset values as well as reported earnings;
- a belief in the individual responsibility of each employee and in nurturing an environment of trust and cooperation so that all employees want to do what needs to be done;
- practice participative management based on open communications and a system which reinforces downward delegation of responsibility, accountability and authority for decision making;
- listen to each other so that issues of concern can be aired and meaningful feedback provided;
- continually look for ways to develop each individual's knowledge and skills through expanding job opportunities and technical and non-technical training;
- encourage a climate for excellence in all areas, for innovation and for an understanding that errors can provide a constructive learning experience;
- provide a financial reward system which is equitable, competitive, essentially based on performance and has a strong element of ownership so that the objectives and return are the same for the shareholder and employee;
- operate the Company's facilities with a high priority for safety and for generally accepted environmental standards;
- encourage participation, both individually and collectively, in community activities in areas in which the Company has operations.

Selected Financial Data

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.

	Years ended December 31				
	1986	1985	1984	1983	1982
		(Stated in thousands of Canadian dollars, except for per share data)			
Net operating revenues	**$112,160**	$143,748	$ 75,409	$ 42,277	$ 27,020
Net earnings	**$ 16,825(b)**	$ 22,966	$ 24,010	$ 16,577	$ 11,894
Net earnings per common share	**$ 0.30(b)**	$ 1.21(a)	$ 2.26*(a)	$ 1.87*(a)	$ 1.38*
Total assets (at end of year)	**$760,519(b)**	$798,558	$674,242	$226,378	$140,635
Long-term obligations including redeemable preferred shares (at end of year)	**$212,121**	$328,406	$255,206	$ 88,384	$ 47,852

(a) Fully diluted earnings per common share were $0.30, $1.10, $1.59*, $1.57* and $1.38* for 1986, 1985, 1984, 1983 and 1982 respectively.

(b) Under United States accounting principles, net loss, net loss per common share and total assets would be $35,555,000, $4.11 and $734,509,000 respectively. See Note 11 to the Consolidated Financial Statements for additional information.

* Restated to reflect stock split of 3:2 effective August 8, 1985.

Corporate Information

Directors

Walter J. Adams
President of Canadian American Loan and Investment Corporation Limited
Calgary, Alberta

Norman R. Gish
President and Chief Executive Officer of the Company
Calgary, Alberta

Paul J. Hill (Director Elect)
President of McCallum Hill Limited
Regina, Saskatchewan

Marshall A. Jacobs
Member of the law firm of Jacobs Persinger & Parker
New York, New York

James F. Kay
Chairman of the Board of Dylex Limited
Toronto, Ontario

David W. Kerr
President of Noranda Inc.
Toronto, Ontario

Willard J. L'Heureux, Q.C.
Senior Vice President Financial Services of Hees International Corporation
Toronto, Ontario

Ross A. MacKimmie, Q.C.
Counsel to the law firm of MacKimmie Matthews
Calgary, Alberta

Paul M. Marshall (Director Elect)
Vice Chairman of Brascan Limited
Toronto, Ontario

Douglas W. Miller
Executive Vice President and President, Petroleum Divison of Westmin Resources Limited
Calgary, Alberta

E. Donald Patterson*
Executive Vice President of Paramount Funding Corp.
Toronto, Ontario

*Mr. Patterson is not standing for re-election

Senior Officers

Norman R. Gish
President and Chief Executive Officer

Grant D. Billing
Senior Vice President Finance and Administration and Corporate Secretary

Donald F. Christensen
Senior Vice President Exploration and Land

William A. Trickett
Senior Vice President Operations

Senior Management

Nick Baiton
General Manager, Production

Thomas W. Buchanan
Controller

Michael D. Callahan
Manager, Project Development

Kent J. Edinga
General Manager, Production Development

Edward J. Flanagan
Manager, Human Resources and Administration

Peter D. Jones
Manager, Information Services

Larry F. Kanuit
Vice President Land

Donald D. McKechnie
Treasurer

W. Keith Miller
Vice President Marketing and Transportation

Michael J. Stone
General Manager, Saskatchewan

John H. Williams
Vice President Exploration

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Registrar and Transfer Agents:

The Royal Trust Company
Calgary, Alberta; Toronto, Ontario; Montreal, Quebec (all issues)
The Bank of Nova Scotia Trust Company
New York, New York (common shares only)

Stock Exchange Listings

Toronto Stock Exchange
The Montreal Exchange
American Stock Exchange

The Company's 1986 Annual Report to the Securities and Exchange Commission on Form 10K is available by writing to the Corporate Secretary at our head office in Calgary, Alberta.

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Printed in Canada

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NORTH CANADIAN OILS LIMITED