SCURRY-RAINBOW OIL LIMITED

Annual Report 1984

Scurry-Rainbow Oil Limited

Corporate Profile

Scurry-Rainbow Oil Limited ("Scurry-Rainbow") is a Canadian company incorporated in 1954 under the laws of the Province of Alberta. The Company is engaged primarily in the exploration for and production of crude oil, natural gas and natural gas liquids. Virtually all activities are carried out in Canada with the major oil and gas producing properties located throughout Alberta, in northeastern British Columbia and in southern Saskatchewan. Frontier exploratory interests are held in the Beaufort Sea, the Arctic Islands and offshore Nova Scotia. Substantial undeveloped coal reserves in southern Alberta and southern British Columbia, and a net profits interest in a producing gold and silver mine in Nevada are also held by the Company.

Approximately 88.5 percent of the common shares of Scurry-Rainbow are owned by Home Oil Company Limited ("Home"), a wholly-owned subsidiary of Hiram Walker Resources Ltd. Scurry-Rainbow holds 72.2 percent of the common shares of Plains Petroleums Limited, a junior Canadian oil and gas company operating primarily in Alberta.

The Company has a Canadian Ownership Rate of 87 percent and is defined as Canadian controlled. This qualifies the Company for the maximum level of Petroleum Incentives Program ("PIP") grants.

Annual General Meeting

The Annual General Meeting of Shareholders will be held on Tuesday, February 5, 1985 at 10:30 a.m. in the Company's head office, 29th floor Auditorium, Home Oil Tower, 324 Eighth Avenue S.W., Calgary, Alberta, Canada. Formal notice of this meeting and proxy materials have been mailed to all registered shareholders with this annual report.

Form 10-K

The Company files annually with the Securities and Exchange Commission of the United States a report on operations known as the Annual Report on Form 10-K. Copies of the Form 10-K are available to shareholders free of charge upon written request to Mr. E. Jorgensen, Comptroller, Scurry-Rainbow Oil Limited, 1700 Home Oil Tower, 324 Eighth Avenue S.W., Calgary, Alberta, Canada, T2P 2Z5.

Metric Conversion Factors

1 kilometre	=	0.62 mile
1 metre	=	3.28 feet
1 hectare	=	2.47 acres
1 cubic metre	=	6.2898 barrels (petroleum liquids)
1 cubic metre	=	35.49373 cubic feet (natural gas)
1 tonne	=	0.984 long tons (sulphur)

Contents

Highlights

	Year ended September 30,		
	1984	1983	1982
Financial (Thousands of Dollars)			
Revenue	**95,420**	82,089	56,574
Net earnings	**24,898**	22,463	14,324
Funds generated from operations	**61,681**	52,554	29,609
Capital expenditures			
Before PIP grants	**91,868**	43,170	24,957
After PIP grants	**45,192**	20,203	20,717
Working capital (deficiency)	**53,877**	35,688	(957)
Per Common Share (Dollars)			
Net earnings	**1.86**	1.68	1.07
Funds generated from operations	**4.61**	3.92	2.21
Operating			
Average Daily Production			
Crude oil and natural gas liquids (barrels)	**7,709**	7,598	6,724
Natural gas (thousands of cubic feet)	**21,711**	20,622	16,824
Proved Reserves			
Crude oil and natural gas liquids (millions of barrels)	**19.2**	17.6	18.9
Natural gas (billions of cubic feet)	**193**	179	169
Sulphur (thousands of long tons)	**341**	367	366
Undeveloped Oil and Gas Acreage			
Gross (thousands of acres)	**3,388**	3,561	4,054
Net (thousands of acres)	**1,072**	1,350	1,395

Vane Orcutt monitoring the master control panel of the water plant at West Eagle Unit No. 1.

To The Shareholders

Financial Results

Scurry-Rainbow enjoyed another record financial performance in 1984. Net earnings rose by 11 percent to $24.9 million or $1.86 per share. Funds generated from operations were $61.7 million or $4.61 per share, a gain of 17 percent. Revenues increased by 16 percent to $95.4 million. The improved financial performance was due to both higher oil prices and increased production volumes.

Capital expenditures more than doubled to $91.9 million, primarily because of increased drilling activity in Western Canada and major exploration commitments in the frontier regions of Canada. PIP grants totalled $46.7 million in 1984 resulting in net capital expenditures of $45.2 million compared with net expenditures of $20.2 million in 1983. Despite the very active program, funds generated from operations were well in excess of current capital expenditures and working capital available to finance future expenditures rose by 51 percent to $53.9 million.

Operating Performance

Drilling activity increased fivefold during 1984 principally as a result of expanded farmin activity in Western Canada. The Company participated in a record 272 working interest wells (31.2 net) during 1984 compared with 53 (11.9 net) in 1983. Of this total, 213 wells were on farmin acreage, where the Company's average earned interest was 3.3 percent. Gross overriding royalty interests were also retained in 46 wells drilled during 1984.

Production of crude oil and natural gas liquids averaged 7,709 barrels per day in 1984, a slight increase from 1983. Sales of natural gas were 21.7 million cubic feet per day, five percent higher than one year earlier.

Discoveries, extensions and net upward revisions of proved reserves exceeded annual production volumes. As a result, proved reserves of crude oil and natural gas liquids increased by nine percent to 19 million barrels, and proved reserves of natural gas reached a record 193 billion cubic feet, up eight percent.

Industry Outlook

The newly-elected federal government has pledged to introduce significant energy policy revisions in consultation with the producing provinces and the petroleum industry. The new measures are expected to be implemented over the next two years and to include market pricing for crude oil and natural gas, replacement of the PIP grants with tax-based incentives, and revisions to the Petroleum and Gas Revenue Tax. Furthermore, the federal government has indicated it will reduce the complexity and scope of regulations affecting the industry. Scurry-Rainbow welcomes these initiatives and is in an excellent position to increase its activities in response to stimulative energy policy changes.

Shortly after the Company's fiscal year-end, the federal government took the first steps toward market pricing for oil and gas. The cost of domestic crude oil to Canadian refiners was raised to world levels through an increase in the federal government's Petroleum Compensation Charge. This charge is included in the refiners' acquisition cost and is used to subsidize the higher prices of oil imports and new domestic production. Eventually, the government plans to eliminate the present administered pricing system and let the marketplace determine the price of oil and gas. Discussions are being held with the producing provinces and the industry with a view to implementing market pricing in 1985.

In November 1984, the federal government eased the export pricing restrictions for natural gas in an effort to increase sales to the United States. The new market-sensitive pricing approach allows gas exporters to renegotiate prices and rates of take for their respective market areas. In accordance with this new policy, the government recently approved amendments to the export licences of six exporters resulting in an average export price of U.S. $3.26 per thousand cubic feet. This more competitive pricing approach is expected to result in increased export revenues as market demand improves in response to the lower price.

In July 1984, the Alberta government issued a White Paper containing proposals for a new industrial and scientific strategy in the province over the period 1985-90. Scurry-Rainbow supports the views of the Canadian Petroleum Association which found the Paper's overall thrust commendable, but stressed that overall reductions in oil and gas royalties should have been included as a viable measure to spur petroleum industry growth in Alberta.

The government of British Columbia introduced a new pricing and royalty system for natural gas which is scheduled to become effective January 1, 1985. The new system represents a significant improvement over the existing regime and its overall impact in the near term should be positive for Scurry-Rainbow. The Company's gas production in British Columbia consists solely of solution gas, which is gas co-produced with oil. This gas, however, represents over 20 percent of Scurry-Rainbow's total annual gas sales. As a result of the submissions made to the government by Scurry-Rainbow and other producers, solution gas will receive particularly favourable treatment under the new regime.

Corporate Outlook

The Company will continue its aggressive drilling program in Western Canada focusing on oil prospects and, to a lesser extent, on high quality gas reserves having near term market potential. In the frontier areas, drilling will continue to test the best geological prospects before the present incentives for frontier exploration are terminated as expected on December 31, 1986. Development activities will be directed towards optimizing existing production and bringing new oil and shut-in gas reserves into production.

Exploratory and development drilling successes are expected to replace production in 1985, more than offsetting natural decline in the Company's mature oil fields. Implementation of a new waterflood project in the East Eagle area of northeastern British Columbia will also mitigate production decline.

Natural gas sales volumes are expected to increase modestly in 1985 as a result of more competitive export pricing and improved export markets. Sufficient deliverability is already available from existing fields to meet this increased demand.

The average wellhead price for the Company's crude oil production will increase when the federal government completes its move to market pricing. The extent of this increase in 1985 will depend on the timing of the government's move and the trend of world prices. The average wellhead price for gas should remain virtually unchanged due to the combined effect of reduced export prices, an early modest increase in the domestic field price, and respective sales volume improvements.

Capital expenditures are expected to decline to about $74 million, or some $43 million after PIP grants, due to reduced expenditures in the frontier regions. Exploration activities will continue to account for approximately 75 percent of total gross expenditures.

Submitted on behalf of the Board of Directors.

R. F. Haskayne

R. F. Haskayne,
President and Chief
Executive Officer

Calgary, Alberta, Canada.
November 28, 1984.

Exploration and Development

Drilling Activity

Scurry-Rainbow's drilling activity in 1984 was more than five times higher than in 1983 due to aggressive exploration and development programs both on Company properties and on lands in which the Company earned interests through farmins. Scurry-Rainbow participated in a total of 272 working interest wells in 1984 compared with 53 last year. On a net well basis, the Company's drilling activity amounted to 31.2 wells in 1984 compared with 11.9 wells in 1983.

The 1984 drilling activity consisted of 113 exploratory and 159 development wells. Of the 113 exploratory wells, 31 (5.1 net) were oil and 23 (2.2 net) were gas. The 159 development wells resulted in 102 (15.8 net) oil and 22 (0.6 net) gas wells. In addition, gross overriding royalty interests were retained in 46 development wells resulting in 33 oil wells and one gas well.

Farmin Agreement with Dome

During 1984, several amendments were made to the farmin agreement with Dome Petroleum Limited ("Dome") covering Scurry-Rainbow's activities in Western Canada and the Beaufort Sea. The expenditure commitment in Western Canada was increased by $25 million to $80 million and the term of the agreement was extended to July 1989. In the Beaufort Sea, the maximum expenditure commitment of $108 million over the three-year period ending in 1986 remained unchanged; however, the maximum interest that may be earned in future wells was increased. During 1984, Scurry-Rainbow participated in the drilling of 213 wells (7.0 net) on Dome lands resulting in 90 oil (2.4 net) and 43 gas wells (1.6 net).

British Columbia

During 1984, Scurry-Rainbow again undertook an active program in British Columbia. Working interests are held in three exploratory wells and 27 development wells drilled during the year. Exploratory drilling resulted in one oil well, while development drilling yielded 22 oil wells.

Servicing a well at West Eagle Unit No. 1.

Working Interest Wells

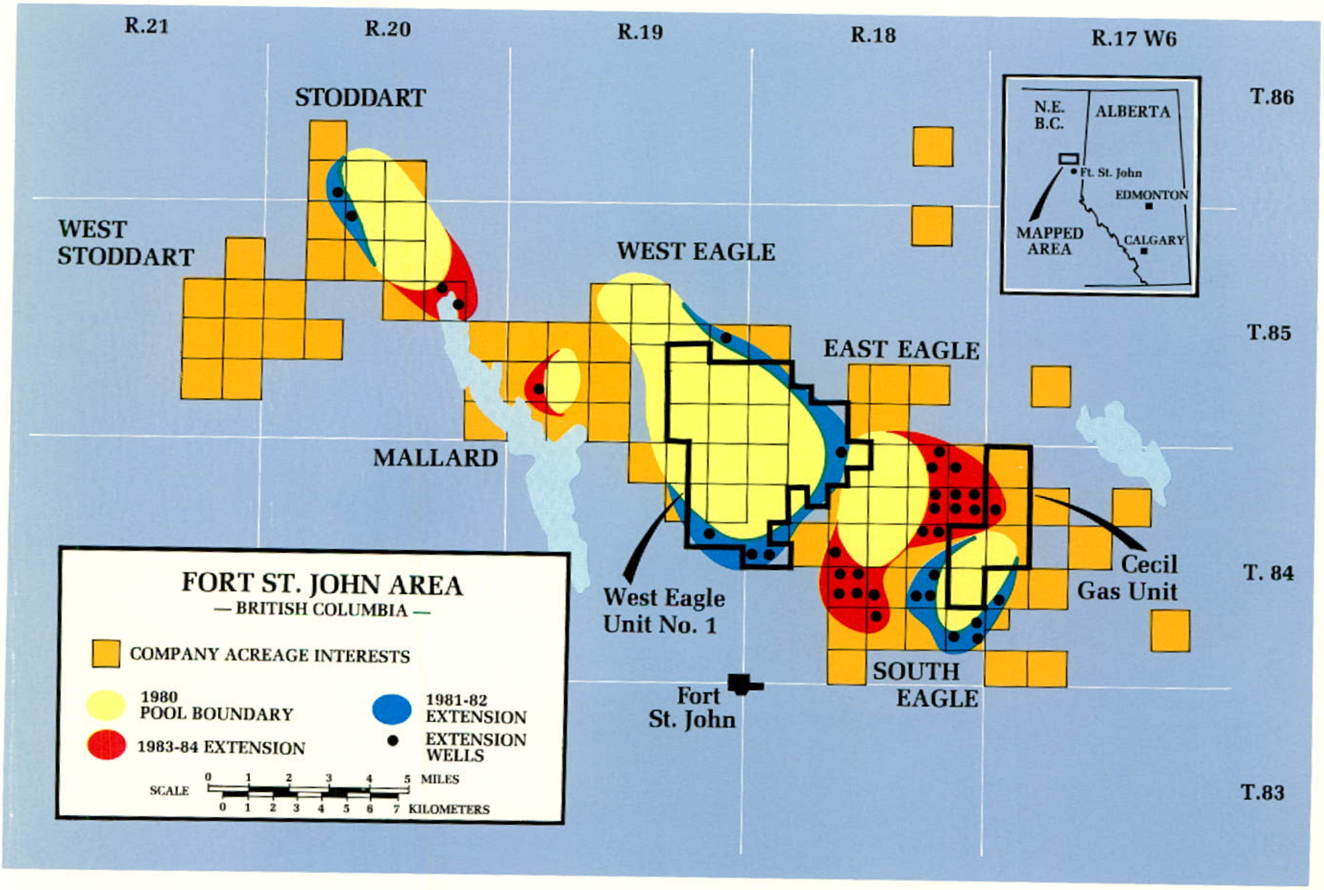
	1984		1983		1982	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Oil	**31**	**5.07**	4	1.20	2	0.28
Gas	**23**	**2.23**	1	0.08	1	0.67
Dry	**59**	**4.99**	4	1.49	4	0.49
	113	**12.29**	9	2.77	7	1.44
Development						
Oil	**102**	**15.81**	28	6.87	15	6.49
Gas	**22**	**0.61**	7	0.42	12	1.67
Dry	**35**	**2.45**	9	1.87	8	5.47
	159	**18.87**	44	9.16	35	13.63
Total	**272**	**31.16**	53	11.93	42	15.07

"Gross" refers to the number of wells in which the Company holds a working interest. "Net" represents the total of the working interests held in each of the gross wells.

Excluded from these statistics are 11 exploratory wells (0.68 net) and six development wells (0.27 net) still drilling at year-end, and any suspended wells.

Development drilling in the fields near Fort St. John in northeastern British Columbia added more than 400 barrels of oil per day to the Company's share of production, an amount greater than the natural decline in other mature fields in 1984.

A new waterflood project, planned for the East Eagle area, calls for the drilling of nine injection wells and the construction of a water plant at a total estimated cost of $10 million. Scurry-Rainbow has approximately a 50 percent interest in East Eagle and expects the provincial government's approval of the project by the fourth quarter of 1985.



Alberta

Scurry-Rainbow holds working interests in 92 exploratory wells and 117 development wells drilled during the year in Alberta. The exploratory drilling yielded 25 oil and 22 gas wells. Of the development wells, 70 were oil and 22 were gas wells. The Company also retained gross overriding royalty interests in three development wells of which one was an oil producer and one a gas producer.

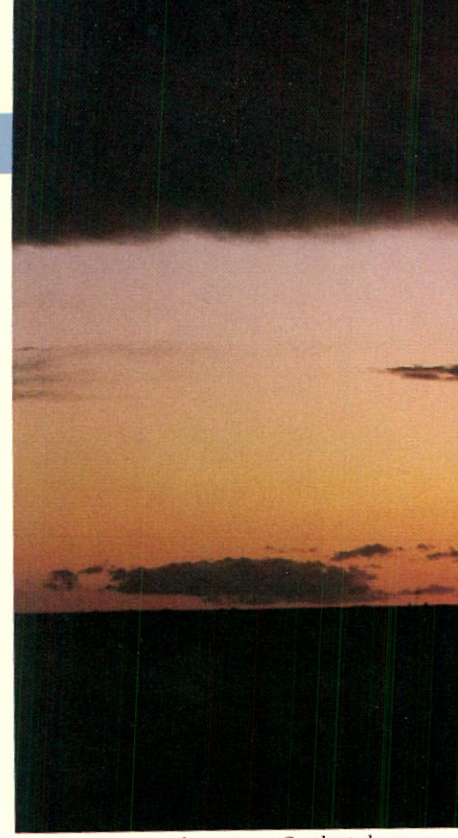
At Gift, in north-central Alberta, where the industry has been very active, the Company participated in two exploratory wells, both of which discovered oil. These were followed by 16 development wells with 15 being successful. Scurry-Rainbow's interests in the 17 oil wells range from 0.7 percent to 2.1 percent.

A major gas and gas liquids play is evolving in the Garrington area, northwest of Calgary, where the Company can earn a substantial land position through the Dome farmout. Two successful exploratory wells were followed by 10 successful development wells and further drilling is planned in 1985. A gas contract is being negotiated for the area. The Company's interests vary between 0.7 percent and 4.2 percent.

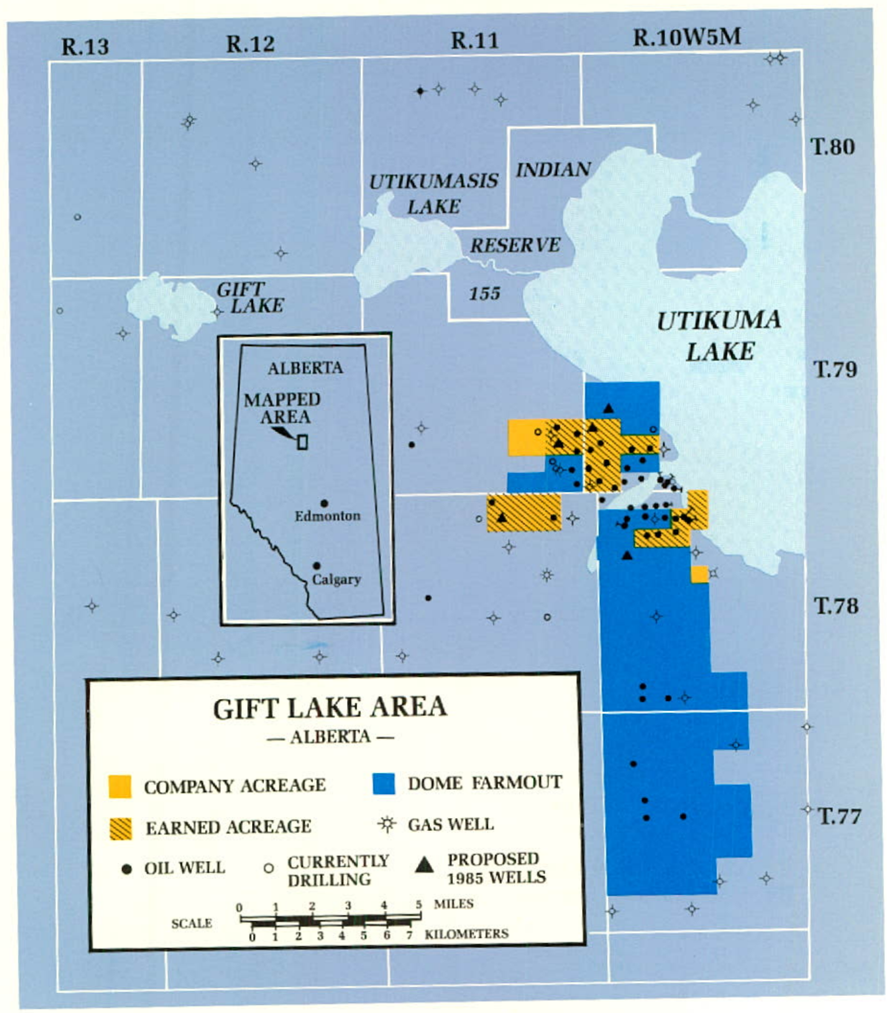
A 16.7 percent interest is held in three oil wells drilled at Steep Creek in the Gold Creek area of western Alberta during 1984. The Company's landholdings in this area are substantial and additional drilling is planned next year.

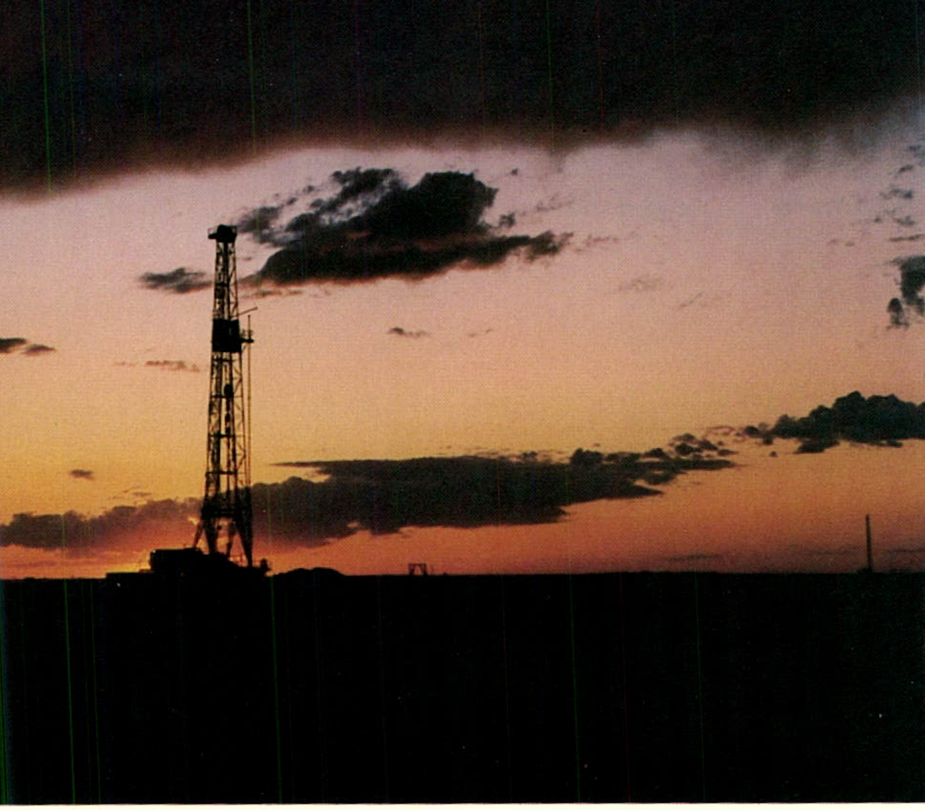
At Carrot Creek, west of Edmonton, Scurry-Rainbow earned a 4.3 percent interest in a successful exploratory well. Here too, the Dome farmout offers Scurry-Rainbow the opportunity to earn extensive landholdings in the area and follow-up wells are planned for 1985.

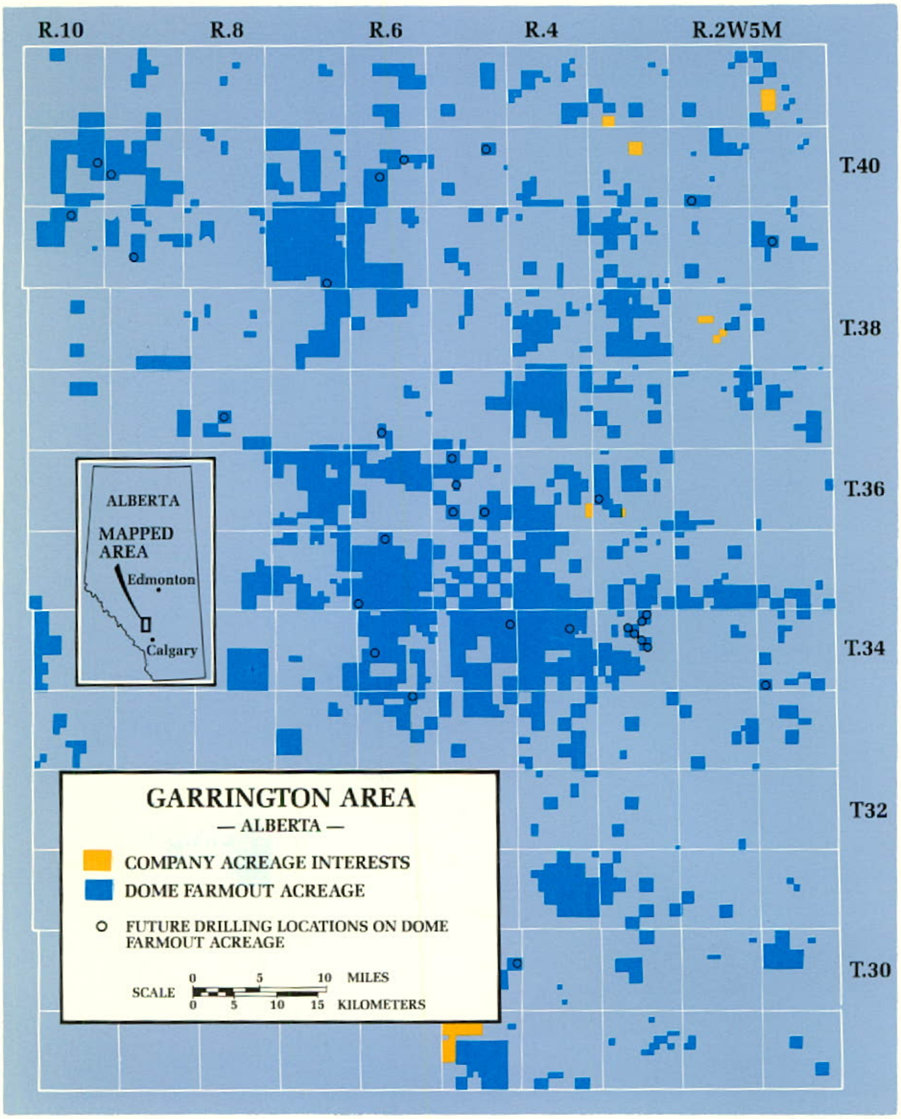
In 1983, the Company earned a 3.1 percent interest in an oil discovery at Tangent located northwest of Edmonton. Production from the well during 1984 averaged approximately 190 barrels of oil per day. A subsequent well was completed as an upper zone gas well and additional wells will be drilled next year.



Drilling in southeastern Saskatchewan.







Following a 1983 oil discovery at Valhalla, southwest of Tangent, two additional exploratory wells were drilled in 1984. One was a successful oil well and the other was abandoned. In this field, Scurry-Rainbow also participated in 14 development wells, all of which were oil producers. The Company's interest in these wells varies from 1.2 to 5.1 percent.

Saskatchewan

In 1984, the Company participated in 30 working interest wells, equally divided between exploratory and development wells. Exploratory drilling resulted in five oil wells and one gas well; development drilling yielded 10 oil wells.

There were 42 wells drilled by other companies on acreage farmed out by Scurry-Rainbow in 1983. Thirty-two of these were completed as oil wells in which the Company retained a gross overriding royalty interest ranging from five percent to 30 percent.

Nova Scotia

In April 1983, the Company agreed to participate in an exploratory program involving the drilling of one well and an option for two additional wells on the 593,000 acre East Sable block offshore Nova Scotia. The first well, Louisbourg J-47, reached a depth of 19,820 feet in July 1984 and tested non-commercial quantities of gas. This well was abandoned in October. The Company expects to start drilling the second well, Citadel H-52, on another structure during the second quarter of 1985. Scurry-Rainbow is paying 14.6 percent of the costs to earn a 7.3 percent interest in each of the wells.

Beaufort Sea

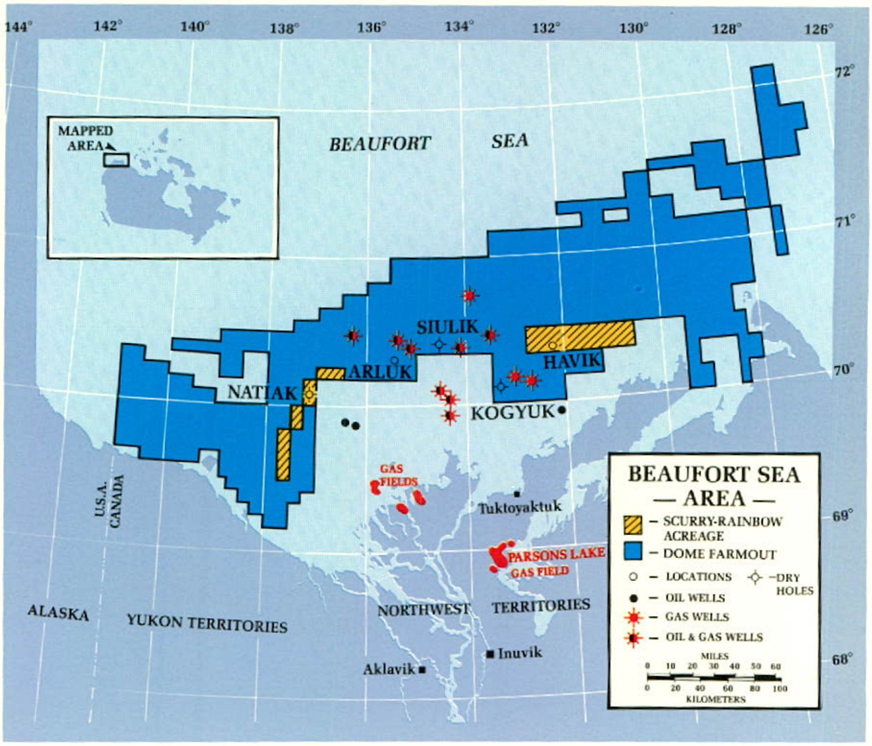
During 1984, Scurry-Rainbow participated in the drilling of five wells which were related to the farmin agreement with Dome.

Two wells, Arluk E-90 and Havik B-41, were suspended at the end of the 1983 drilling season and were reentered this summer. Arluk was drilled to a total depth of 14,100 feet. Testing began in October, but was suspended until next summer due to ice conditions. The Company is paying 9.8 percent of Arluk's costs to earn a 4.9 percent interest. Havik was drilled to a total depth of 15,580 feet; however, a mechanical problem with the wellhead and encroaching ice forced postponement of testing until the 1985 drilling season. Havik was drilled on lands owned by Scurry-Rainbow; thus, the Company paid its 20 percent working interest share of costs.

Three other Beaufort Sea wells were dry and abandoned. The Siulik I-05 well, where the Company paid 8.3 percent of the costs to earn a 4.2 percent interest, flowed only minor amounts of crude oil during testing and was abandoned in October 1984. The Natiak O-44 well, abandoned in September 1984, was drilled on Scurry-Rainbow lands with the Company paying its 20 percent working interest share of costs. The Kogyuk N-67 well was abandoned in January 1984 and the Company paid 3.8 percent of the costs to earn a 1.9 percent interest.

Arctic Islands

On the Sabine Peninsula block, the Company participated in the Sherard Bay F-34 well, which was drilled to a depth of 17,870 feet and abandoned in May 1984.



Oil and Gas Acreage

	Undeveloped Acreage	
	Gross	Net
Canada		
Alberta	932,045	158,058
Arctic Islands	726,620	83,269
Beaufort Sea	676,406	124,244
British Columbia	229,309	52,988
Saskatchewan	691,751	626,234
Other	27,162	25,722
	3,283,293	1,070,515
International		
Netherlands Offshore	104,770	1,603
Total	3,388,063	1,072,118
Hectares	1 371 685	434 056

"Undeveloped acreage" is defined as exploratory lands on which wells have not been drilled or completed to a point that would permit production.

"Gross" refers to the total number of acres in which Scurry-Rainbow holds either a working interest or an overriding royalty interest. "Net" is determined by multiplying the gross acres by the percentage of the working interests held by the Company in the gross acres. Overriding royalty interests are not used in calculating net acres.

The table excludes 776,294 gross acres (131,367 net) of developed lands in Western Canada. Developed acreage is defined as lands from which production is being obtained or is capable of being obtained.

Average Daily Production/Sales
(Before Royalties and Minority Interests)

	1984		1983		1982	
	Petroleum Liquids*	**Natural Gas**	**Petroleum Liquids***	**Natural Gas**	**Petroleum Liquids***	**Natural Gas**
	(barrels)	(thousands of cubic feet)	(barrels)	(thousands of cubic feet)	(barrels)	(thousands of cubic feet)
Alberta	**1,541**	**16,730**	1,455	16,732	1,329	12,249
British Columbia	**4,307**	**4,718**	4,200	3,403	3,915	4,438
Saskatchewan	**1,761**	**263**	1,841	457	1,357	129
Other	**100**	**—**	102	30	123	8
Total	**7,709**	**21,711**	7,598	20,622	6,724	16,824
Total (in cubic metres per day)	**1 226**	**612**	1 208	581	1 069	474

* Includes crude oil and natural gas liquids

Production/Sales

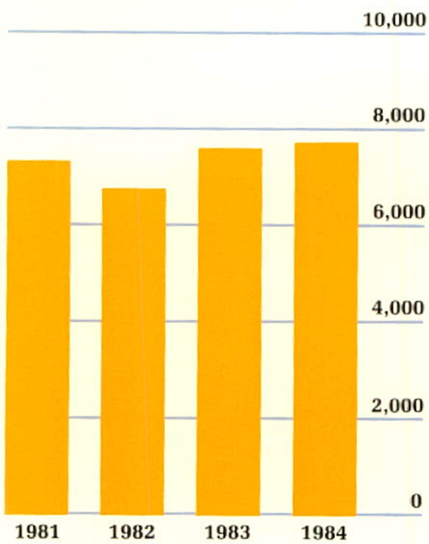
Production of crude oil and natural gas liquids in 1984 averaged 7,709 barrels per day compared with 7,598 barrels per day in 1983. Successful drilling programs in Alberta and British Columbia more than offset the natural decline of mature fields in British Columbia and Saskatchewan.

Scurry-Rainbow's major oil producing properties are located in the Fort St. John area of British Columbia. This is a mature area undergoing considerable natural decline; however, an aggressive development drilling program was successful in adding more than 400 barrels per day to the Company's production and approximately 1.5 million barrels to proved reserves.

Natural gas sales averaged 21.7 million cubic feet per day during 1984, up five percent from 20.6 million cubic feet per day last year. The increase was due to higher sales volumes at Gold Creek in western Alberta and in the Fort St. John area. These exceeded volume decreases at South Wapiti and Karr near Gold Creek, and at Crossfield-Turner Valley in southern Alberta.

AVERAGE DAILY PRODUCTION PETROLEUM LIQUIDS*

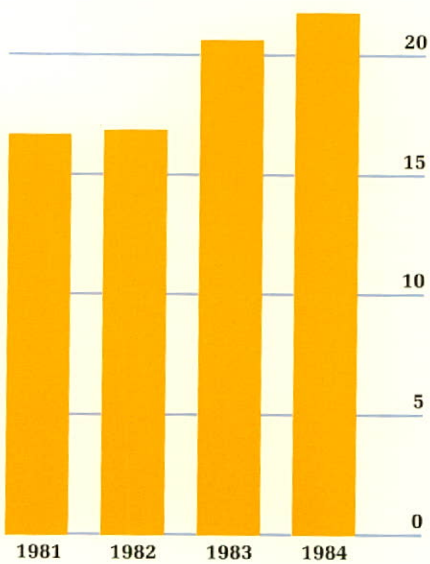
(BARRELS)



**Includes crude oil and natural gas liquids*

AVERAGE DAILY SALES NATURAL GAS

(MILLIONS OF CUBIC FEET)



Proved Reserves (Before Royalties and Minority Interests)	**Crude Oil** (thousands of barrels)	**Natural Gas Liquids** (thousands of barrels)	**Natural Gas** (billions of cubic feet)	**Sulphur** (thousands of long tons)
September 30, 1983	15,945	1,610	178.9	366.9
Discoveries/Extensions	2,107	239	16.4	15.7
Revisions	1,824	274	5.4	(17.5)
Production/Sales	(2,673)	(148)	(7.9)	(24.4)
September 30, 1984	17,203	1,975	192.8	340.7
Millions of cubic metres	2.735	0.314	5 431.9	
Thousands of tonnes				346.2

Proved Reserves

Discoveries and extensions resulting from successful drilling along with net upward revisions reflecting improved reservoir performance added 3.9 million barrels of crude oil to proved reserves. These additions were greater than the 2.7 million barrels produced during the year and resulted in an eight percent increase in oil reserves. Most of the discoveries and extensions were recorded in the Fort St. John area, and a major review of reservoir performance in Saskatchewan resulted in substantial upward revisions.

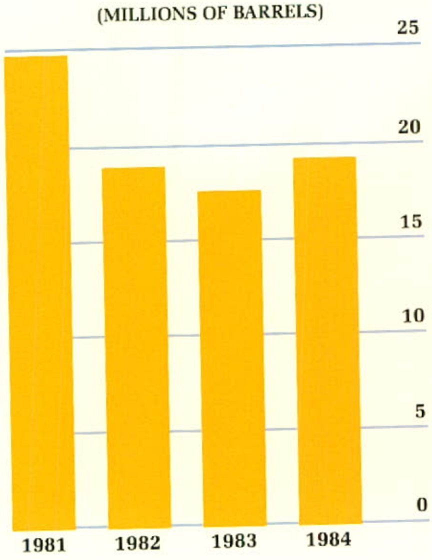
Proved reserves of natural gas liquids rose by 23 percent to 2.0 million barrels. Discoveries, extensions and net upward revisions added 513,000 barrels compared with sales of 148,000 barrels. Most of the discoveries and extensions resulted from successful drilling in the Garrington and Caroline areas of central Alberta; and upward revisions occurred primarily in the Gold Creek area.

Natural gas reserves reached 192.8 billion cubic feet, an increase of eight percent. Discoveries and extensions from successful drilling in the Fort St. John, Garrington and Caroline areas combined with upward revisions at Wapiti and South Wapiti more than replaced sales.

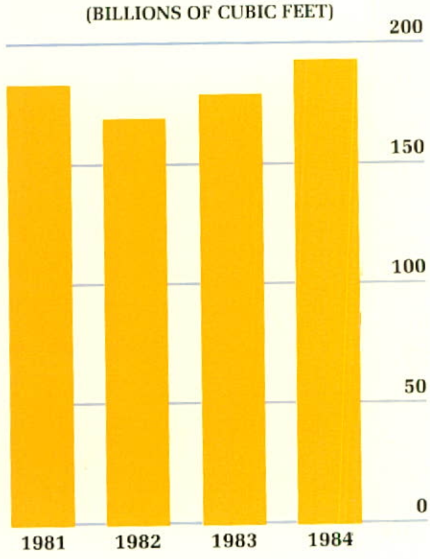
Proved reserves of sulphur declined by seven percent to 340,700 long tons due to increased sales and downward revisions at Crossfield and East Crossfield near Calgary, Alberta.

Proved reserves are the estimated quantities of crude oil, natural gas liquids, natural gas and sulphur which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The reserve estimates are prepared by Company engineers.

PROVED RESERVES OIL & GAS LIQUIDS
(MILLIONS OF BARRELS)



PROVED RESERVES NATURAL GAS
(BILLIONS OF CUBIC FEET)



Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's discussion relates to the results of operations, financial condition and changes in financial condition for the three years ended September 30, 1984. These comments should be read in conjunction with the consolidated financial statements, unaudited supplementary information, and the five-year financial and operating reviews.

Earnings

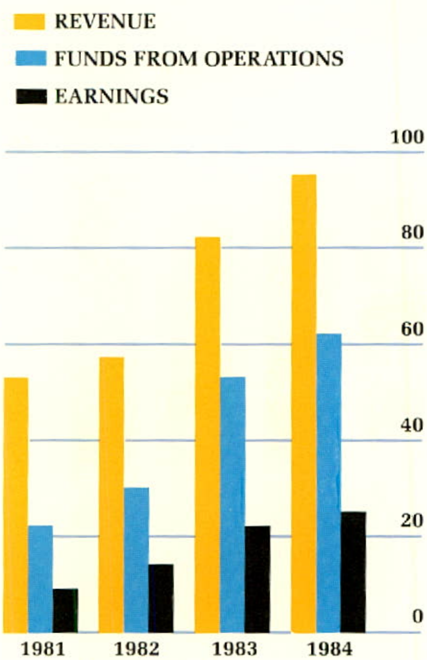
Scurry-Rainbow achieved record earnings in 1984. Net earnings were $24.9 million, up from $22.5 million in 1983 and 74 percent higher than the $14.3 million recorded in 1982. Improved earnings reflect increased production and prices for oil and gas and higher investment income. Net earnings per common share were $1.86 compared with $1.68 in 1983 and $1.07 in 1982.

Revenue

Crude oil revenue increased 65 percent to $67.4 million over the three-year period mainly as a result of a 44 percent increase in wellhead prices and a 13 percent increase in production. Increased prices are attributed to a larger percentage of production qualifying for the New Oil Reference Price ("NORP"), essentially the world price, as a result of federal/provincial agreements signed in 1983. Approximately 56 percent of the Company's oil production attracts NORP compared with 16 percent in 1983 and 3 percent in 1982. Oil production averaged 7,304 barrels per day compared with 7,227 barrels per day in 1983 and 6,460 in 1982. Increased production is attributed to new wells in the Fort St. John area of British Columbia and infill drilling at the Harmattan Elkton Unit in Alberta. Royalty rates declined marginally over the three-year period and averaged 24.6 percent in 1984.

Natural gas revenue increased $6.2 million over the three-year period to $18.7 million in 1984. Wellhead prices for gas averaged $2.84 per thousand cubic feet, up $0.04 from 1983 and $0.38 from 1982 prices. Scheduled price increases for 1984 did not materialize since the price of natural gas is tied to 65 percent of the Toronto refinery gate price of crude oil. Gas production increased 29 percent to 21.7 million cubic feet per day over the three-year period as a result of new gas sales from the South Wapiti, Gold Creek and Karr areas of Alberta.

REVENUE
FUNDS FROM OPERATIONS
EARNINGS
(MILLIONS OF DOLLARS)



Revenue

	1984	1983	1982
	(thousands of dollars)		
Crude oil	**$67,356**	$57,056	$40,727
Natural gas	**18,722**	17,943	12,503
Natural gas liquids	**3,036**	2,599	1,406
Sulphur	**1,317**	1,381	1,149
Mining	**—**	—	310
Other	**4,989**	3,110	479
	$95,420	$82,089	$56,574

Expenses and Taxes

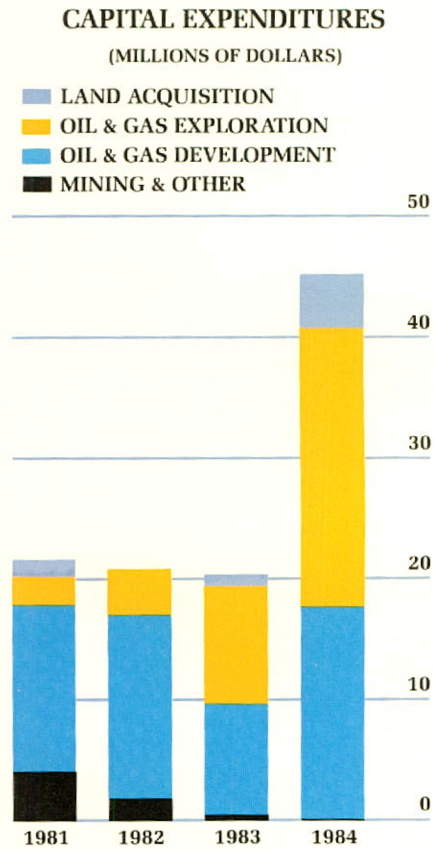
Operating expenses totalled $13.2 million, up marginally from 1983, reflecting increased mineral taxes in British Columbia. Operating expenses declined in 1983 as a result of the sale of the Gooseberry gold and silver mine. Oil and gas depletion rates per equivalent barrel declined marginally to $3.54 from $3.59 in 1983. However, these rates are up substantially from the $2.69 per equivalent barrel experienced in 1982, reflecting increased finding and development costs.

Taxes more than doubled to $38.2 million in 1984 from $16.3 million in 1982. Factors which contributed to this increase include the phasing out of earned depletion allowances which increased the effective income tax rate to 46.8 percent in 1984 from 40.1 percent in 1982. Effective January 1, 1984, the Alberta government reduced the Alberta Royalty Tax Credit from 75 percent of Alberta royalties paid with a maximum of $4 million to 50 percent of Alberta royalties paid with a maximum of $2 million. In addition, the Petroleum and Gas Revenue Tax was increased from 8 percent at December 31, 1981 to the current effective rate of 12 percent on conventional production.

Capital Expenditures and Corporate Liquidity

Capital expenditures, after PIP grants, increased significantly during 1984 to $45.2 million, up from the $20.2 million expended in 1983 and $20.7 million in 1982. Exploration accounted for $27.6 million of the 1984 program, of which approximately $7.9 million was spent on exploratory drilling in the Beaufort Sea and $1.6 million offshore Nova Scotia. The Company continued its exploratory effort in Western Canada with expenditures of $17.1 million, of which $4.4 million was spent on land acquisitions. Development accounted for $17.4 million of the 1984 program mostly in the Fort St. John area of British Columbia. Capital expenditures for 1985 are projected at $43.4 million after PIP grants.

Improved product prices and increased production served to increase the flow of funds from operations to $61.7 million, up from $52.6 million generated in 1983 and more than double the 1982 flow. Total sources of funds were sufficient to finance the capital program and debt obligations; consequently, at year-end the Company had working capital of $53.9 million, up $18.2 million from 1983 and a working capital deficiency of $1 million in 1982. In the opinion of management, working capital and available credit facilities of $15.0 million are sufficient to meet anticipated capital requirements.



Consolidated Balance Sheet

	September 30, 1984	September 30, 1983
	(Expressed in thousands)	
ASSETS		
CURRENT ASSETS		
Cash and short term investments	**$ 14,041**	$ 220
Advances to parent company (note 9)	**8,310**	25,300
Accounts receivable		
Trade	**14,793**	13,621
Petroleum incentives program	**41,742**	23,832
Inventories, at lower of cost or net realizable value	**1,062**	650
	79,948	63,623
INVESTMENT IN 50% OWNED COMPANY	**1,053**	1,054
PROPERTY, PLANT AND EQUIPMENT (note 2)	**170,753**	141,587
OTHER ASSETS (note 2)	**4,846**	5,271
	$256,600	$211,535
LIABILITIES		
CURRENT LIABILITIES		
Bank indebtedness (note 3)	**$ 2,031**	$ 2,711
Accounts payable	**17,884**	14,538
Taxes payable	**4,709**	9,750
Due to parent company	**1,447**	905
Current portion of long term debt	**—**	31
	26,071	27,935
DEFERRED PRODUCTION REVENUE (note 4)	**4,319**	2,860
LONG TERM DEBT (note 5)	**6,897**	7,689
DEFERRED INCOME TAXES	**72,999**	52,080
MINORITY INTEREST	**2,367**	1,922
SHAREHOLDERS' EQUITY		
CAPITAL STOCK (note 6)	**9,374**	9,374
CONTRIBUTED SURPLUS	**23,334**	23,334
RETAINED EARNINGS	**111,239**	86,341
CAPITAL COMMITMENTS (note 10)		
	143,947	119,049
	$256,600	$211,535

Approved by the Board

R. J. Hashugne Director

Robert G. Black Director

Consolidated Statement of Earnings and Retained Earnings

	Year ended September 30,		
	1984	1983	1982
	(Expressed in thousands except per share amounts)		
REVENUE			
Operating	**$ 90,431**	$ 78,979	$ 56,095
Other (note 9)	**4,989**	3,110	479
	95,420	82,089	56,574
EXPENSE			
Operating	**13,159**	12,134	12,673
General and administrative	**2,591**	2,303	1,471
Depletion and depreciation	**15,715**	15,029	9,713
Interest on long term debt	**364**	416	1,044
Other interest	**68**	29	1,029
Minority interest	**445**	338	26
	32,342	30,249	25,956
EARNINGS BEFORE TAXES	**63,078**	51,840	30,618
TAXES (note 7)	**38,180**	29,377	16,294
NET EARNINGS	**24,898**	22,463	14,324
RETAINED EARNINGS AT BEGINNING OF YEAR	**86,341**	63,878	49,554
RETAINED EARNINGS AT END OF YEAR	**$111,239**	$ 86,341	$ 63,878
EARNINGS PER SHARE	**$ 1.86**	$ 1.68	$ 1.07

Consolidated Statement of Changes in Financial Position

	Year ended September 30, 1984	1983	1982
	(Expressed in thousands)		
FUNDS WERE PROVIDED FROM			
Operations			
Net earnings	**$ 24,898**	$ 22,463	$ 14,324
Items not affecting funds			
Depletion and depreciation	**15,715**	15,029	9,713
Deferred income taxes	**20,919**	15,280	5,948
Other	**149**	(218)	(376)
	61,681	52,554	29,609
Disposal of property, plant and equipment	**311**	9,123	366
Deferred production revenue	**1,459**	941	287
Other	**629**	—	263
	64,080	62,618	30,525
FUNDS WERE USED FOR			
Property, plant and equipment	**45,192**	20,203	20,717
Reduction in long term debt	**699**	1,487	6,147
Other	**—**	4,283	—
	45,891	25,973	26,864
INCREASE IN WORKING CAPITAL	**18,189**	36,645	3,661
WORKING CAPITAL (DEFICIENCY) AT BEGINNING OF YEAR	**35,688**	(957)	(4,618)
WORKING CAPITAL (DEFICIENCY) AT END OF YEAR	**$ 53,877**	$ 35,688	$ (957)
CHANGES IN COMPONENTS OF WORKING CAPITAL			
INCREASE (DECREASE) IN CURRENT ASSETS			
Cash and short term investments	**$ 13,821**	$ (5,936)	$ 6,091
Advances to parent company	**(16,990)**	25,300	—
Notes receivable from an affiliated company	**—**	—	(2,534)
Accounts receivable			
Trade	**1,172**	(1,188)	6,446
Petroleum incentives program	**17,910**	16,286	4,240
Inventories	**412**	(1,019)	(375)
	16,325	33,443	13,868
INCREASE (DECREASE) IN CURRENT LIABILITIES			
Bank indebtedness	**(680)**	(2,409)	240
Accounts payable	**3,346**	(1,289)	4,730
Taxes payable	**(5,041)**	1,299	4,611
Due to parent company	**542**	(803)	625
Current portion of long term debt	**(31)**	—	1
	(1,864)	(3,202)	10,207
INCREASE IN WORKING CAPITAL	**$ 18,189**	$ 36,645	$ 3,661

Notes to 1984 Consolidated Financial Statements

(Tabular amounts, except per share amounts, are expressed in thousands)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Company's significant accounting policies, which conform with accounting principles generally accepted in Canada, are summarized below:

Principles of Consolidation

The consolidated financial statements include the accounts of all companies in which the Company has ownership of more than 50 percent of the voting capital stock.

The Company follows the equity method of accounting for its investment in a 50 percent owned company. Under this method the Company's investment is carried at cost plus its share of undistributed earnings since the date of acquisition.

The excess of the cost, of shares of subsidiaries and the company accounted for by the equity method, over the underlying net book value at dates of acquisition has been allocated to property, plant and equipment.

Substantially all of the exploration and production activities of the Company are conducted jointly with others and these financial statements reflect the Company's proportionate interest in such activities.

Oil and Gas Operations

The Company follows the full cost method of accounting for oil and gas operations whereby all exploration and development costs are capitalized and charged against earnings as set out below. Capitalized costs include land acquisition costs, geological and geophysical costs, lease rentals and related charges applicable to non-producing property, costs of drilling both productive and non-productive wells, and overhead charges related to exploration and development activities. Such costs are generally limited to the future net revenues from estimated production from proved reserves at current prices and costs and the estimated fair market value of unproved properties. A separate cost centre is established for each country. Proceeds of disposals are generally credited to cost and no gains or losses are recognized unless such disposals constitute a major disposition. Costs are depleted using the unit of production method based upon estimated proved reserves, as determined by Company engineers. Natural gas reserves and production are converted to equivalent volumes of crude oil based on the relative energy content.

Buildings and equipment, other than production equipment, are depreciated on a straight-line basis at rates which are estimated to amortize the costs of the assets, less salvage values, over their useful lives. Production equipment is depreciated using the unit of production method.

Mining Costs

Mining costs are charged to earnings in the period incurred (included in depletion) until such time as the presence of economically recoverable reserves is established. Proceeds on partial disposition of properties are generally deducted from the related costs without recognition of gain or loss.

2. PROPERTY, PLANT AND EQUIPMENT

	September 30, 1984		
	Cost	Accumulated depletion and depreciation	Net
Petroleum and natural gas properties and equipment	$273,743	$108,371	$165,372
Mining properties and equipment			
Developed	4,603	1,142	3,461
Undeveloped	4,772	2,993	1,779
Land, buildings and other equipment	448	307	141
	$283,566	$112,813	$170,753

	September 30, 1983		
	Cost	Accumulated depletion and depreciation	Net
Petroleum and natural gas properties and equipment	$226,311	$ 90,928	$135,383
Mining properties and equipment			
Developed	4,603	345	4,258
Undeveloped	4,744	2,962	1,782
Land, buildings and other equipment	425	261	164
	$236,083	$ 94,496	$141,587

Costs of petroleum and natural gas properties at September 30, 1984 have been reduced by credits of $77,189,000 (1983 — $30,513,000) with respect to Petroleum Incentives Program grants. Exploration and development expenditures for the year ended September 30, 1984, have been reduced by grants of $46,676,000 (1983 — $22,967,000).

The developed mining properties and equipment pertain to the mining operations in Nevada. On January 10, 1983, the Company sold the Gooseberry gold and silver mine in Nevada for a cash consideration of U.S. $3 million and non-interest bearing notes aggregating U.S. $6 million payable equally over ten years commencing January 31, 1984. In recording the transaction, the proceeds were credited to cost and the Canadian value of the notes was discounted at a rate of 10 percent to $4,535,000; currently $4,253,000 is included in other assets. The Company has retained a net profits interest ranging from 15 percent to 30 percent depending on the price of gold.

3. BANK INDEBTEDNESS

As at September 30, 1984, the Company had unused operating lines of credit totalling $10,000,000, which upon drawdown would bear interest at prime rate and would be partially secured by a general assignment of certain accounts receivable and interests in certain petroleum and natural gas properties.

4. DEFERRED PRODUCTION REVENUE

Amounts paid to the Company by purchasers, for annual contracted gas volumes not taken, are recorded as deferred production revenue. These amounts will be reported as revenue when the gas to which the payments relate is delivered to the purchaser. Deliveries or repayments are to be made over a maximum 10 year period commencing November 1, 1984.

5. LONG TERM DEBT

	September 30, 1984	1983
7.25% Subordinated Debentures	**$ 6,897**	$ 7,505
Other	**—**	215
	6,897	7,720
Less: Current portion	**—**	31
	$ 6,897	$ 7,689

As at September 30, 1984, the Company had an unused bank revolving capital loan facility of $5,000,000, which upon drawdown would bear interest at prime rate. The loan can be drawn on a revolving basis for two years and thereafter will be convertible into a six-year term loan with interest to be applied at prime plus one-quarter percent.

The 7.25% Subordinated Debentures, due May 1, 1988, are subject to annual sinking fund requirements of $1,067,000 on November 1, of each year. Debentures purchased by the Company may be applied against the sinking fund obligations. Debentures purchased to September 30, 1984 satisfy installment requirements to November 1, 1984 and a balance of $299,000 remains to be applied against subsequent sinking fund requirements.

The estimated amount of long term debt maturities and sinking fund requirements for the fiscal years subsequent to September 30, 1984 are as follows: 1986 — $768,000; 1987 — $1,067,000; 1988 — $5,062,000.

6. CAPITAL STOCK

The authorized capital stock of the Company consists of 100,000,000 preferred shares, without par value, and 200,000,000 common shares, without par value. As at September 30, 1984 and 1983, the Company had 13,391,780 common shares issued and outstanding.

7. TAXES

Taxes are comprised of the following:

	Year ended September 30, 1984	1983	1982
Income taxes			
Current	**$ 8,628**	$ 8,660	$ 6,318
Deferred	**20,919**	15,280	5,948
	29,547	23,940	12,266
Petroleum and gas revenue tax	**12,051**	9,616	5,871
Incremental oil revenue tax	**—**	—	1,246
Alberta royalty tax credit	**(3,418)**	(4,179)	(3,089)
Total taxes	**$38,180**	$29,377	$16,294
Total taxes as a percentage of earnings before taxes	**60.5%**	56.7%	53.2%

Income taxes differ from the amounts which would be obtained by applying the Canadian statutory federal income tax rate of 46 percent to the respective years' pretax earnings. These differences result from the following:

	Year ended September 30,		
	1984	**1983**	**1982**
Earnings before taxes	**$ 63,078**	$ 51,840	$ 30,618
Computed "expected" income taxes	**$ 29,016**	$ 23,846	$ 14,085
Royalties and other payments to provincial governments	**11,037**	9,535	6,623
Federal resource allowance	**(10,917)**	(9,280)	(6,130)
Depletion allowances on Canadian oil and gas production income	**(1,125)**	(1,333)	(2,378)
Provincial income taxes, net of federal income tax abatement	**1,549**	1,267	691
Other	**(13)**	(95)	(625)
Actual income taxes	**$ 29,547**	$ 23,940	$ 12,266
Actual income taxes as a percentage of earnings before taxes	**46.8%**	46.2%	40.1%

Deferred income taxes arise from the following:

	Year ended September 30,		
	1984	**1983**	**1982**
Exploration and development costs deducted for income tax purposes in excess of related provision for depletion	**$ 20,585**	$ 15,564	$ 5,216
Capital cost allowance claimed for income tax purposes in excess of related provision for depreciation	**334**	(284)	732
	$ 20,919	$ 15,280	$ 5,948

8. BUSINESS AND GEOGRAPHIC SEGMENTS

The Company has only one significant business segment being its oil and gas operations which are conducted principally in Canada.

9. RELATED PARTY TRANSACTIONS

Home Oil Company Limited ("Home") owns approximately 88.5 percent of the issued and outstanding shares of the Company. During the year ended September 30, 1984, Home provided certain management, accounting, administrative, technical and other services to the Company at cost, which amounted to $9,200,000 (1983 — $6,111,000; 1982 — $5,245,000).

Advances to parent company carry interest at one-quarter percent above the cost of funds in the commercial paper market and are repayable on demand. Interest received from the parent company for the year ended September 30, 1984, amounted to $3,605,000 (1983 - $1,573,000).

During 1983, the Company sold its remaining oil and gas properties in the United States to an affiliated company for $1,136,000.

10. CAPITAL COMMITMENTS

Under the revised terms of agreements with Home, Dome Petroleum Limited and Dome Canada Limited, the Company agreed to invest a maximum of $188 million over a six-year period which commenced July 7, 1983. In the western Canadian provinces, the Company has committed to spend $80 million on exploration and development programs. Up to $108 million is committed to be spent on exploratory lands in the Beaufort Sea. The Company qualifies for maximum grants under the Petroleum Incentives Program. Accordingly, eligible expenditures incurred in Western Canada entitle the Company to grants of 35 percent of exploration costs and 20 percent of development costs. Eligible exploration costs in the Beaufort Sea entitle the Company to grants of 80 percent. The Company's commitment to the Beaufort Sea program is contingent on the continuance of the Petroleum Incentives Program grants. Under both programs, gross expenditures of $77 million have been incurred to September 30, 1984, entitling the Company to Petroleum Incentives Program grants of $56 million.

Unaudited Supplementary Information

SELECTED QUARTERLY FINANCIAL DATA

	Quarter ended			
	September 30, 1984	June 30, 1984	March 31, 1984	December 31, 1983
Revenue	**$22,956**	**$27,863**	**$24,140**	**$20,461**
Gross margin	**$19,265**	**$23,809**	**$19,532**	**$17,064**
Net earnings	**$ 5,767**	**$ 7,783**	**$ 5,850**	**$ 5,498**
Earnings per share	**$ 0.43**	**$ 0.58**	**$ 0.44**	**$ 0.41**

	Quarter ended			
	September 30, 1983	June 30, 1983	March 31, 1983	December 31, 1982
Revenue	$20,673	$18,658	$23,626	$19,132
Gross margin	$16,497	$15,412	$19,782	$15,961
Net earnings	$ 5,918	$ 5,122	$ 6,745	$ 4,678
Earnings per share	$ 0.44	$ 0.38	$ 0.51	$ 0.35

OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES

The Company's oil and gas exploration and production activities are carried out principally in Canada. The following unaudited supplementary oil and gas information is provided in accordance with the United States' Statement of Financial Accounting Standards No. 69, "Disclosures about Oil and Gas Producing Activities".

Capitalized Costs

	September 30,		
	1984	1983	1982
Petroleum and natural gas properties	**$273,743**	$226,311	$214,610
Accumulated depletion and depreciation	**(108,371)**	(90,928)	(83,106)
Net capitalized costs	**$165,372**	$135,383	$131,504

Costs Incurred

	Year ended September 30,		
	1984	1983	1982
Acquisition of unproved properties	**$ 4,421**	$ 773	$ —
Exploration	**23,194**	9,760	3,594
Development	**17,438**	9,355	15,325
Other	**95**	102	106
	$ 45,148	$ 19,990	$ 19,025

Results of Operations

	Year ended September 30,		
	1984	1983	1982
Revenue, net of royalties	**$90,431**	$78,979	$55,785
Production costs	**13,159**	11,813	11,164
Petroleum and gas revenue tax	**12,051**	9,616	5,871
Incremental oil revenue tax	**—**	—	1,246
Depletion and depreciation	**14,870**	14,627	9,472
	40,080	36,056	27,753
Income before income taxes from oil and gas operations	**50,351**	42,923	28,032
Income taxes (net of Alberta royalty tax credit)	**25,887**	20,031	11,426
Results of oil and gas operations (excluding general and administrative overhead and interest costs)	**$24,464**	$22,892	$16,606

Proved Oil and Gas Reserve Quantities

The Company's proved reserves are based on estimates made by Company engineers. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. The process of estimating reserves is complex, requiring subjective judgements in the evaluation of available geological, engineering, economic, and other data. All of the Company's proved reserves are located in Canada.

The calculation of reserves of crude oil, including condensate and natural gas liquids, and natural gas is based on the Company's share of proved reserves, after the deduction of royalties.

	Crude oil (thousands of barrels)			Natural gas (billions of cubic feet)		
	1984	1983	1982	**1984**	1983	1982
Proved Reserves						
Beginning of year	**13,733**	14,183	15,586	**146**	134	105
Revisions of previous estimates and improved recovery	**742**	478	(363)	**(6)**	15	18
Extensions and discoveries	**1,882**	1,127	791	**12**	3	16
Production	**(2,132)**	(2,055)	(1,831)	**(7)**	(6)	(5)
End of year	**14,225**	13,733	14,183	**145**	146	134
Proved Developed Reserves						
Beginning of year	**12,936**	14,183	15,586	**132**	134	105
End of year	**14,202**	12,936	14,183	**133**	132	134

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

Estimated future cash inflows are computed by applying year-end prices, except for fixed and determinable escalation provisions in contracts, to year-end quantities of proved oil and gas reserves. Estimated future development costs, production costs, Petroleum and Gas Revenue Tax ("PGRT"), and income taxes (net of Alberta Royalty Tax Credit), are deducted from estimated future cash inflows to arrive at estimated future net cash flows. Future development and production costs are based on year-end costs and assume continuation of existing economic and operating conditions. Estimated future PGRT is computed based on rates and legislation in effect at year-end. Future income taxes are computed by applying the year-end statutory rates to the future pretax net cash flows, after making provision for the tax basis of the oil and gas properties. Future net cash flows are discounted at a rate of 10 percent per annum to arrive at discounted future net cash flows.

The Company cautions that the discounted future net cash flows from proved oil and gas reserves is neither an indication of fair market value of the Company's oil and gas properties, nor of the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development and production costs, and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent may not appropriately reflect future interest rates.

Standardized Measure of Discounted Future Net Cash Flows

	September 30,		
	1984	**1983**	**1982**
Future cash inflows	**$ 872,770**	$ 854,872	$ 817,895
Future costs			
Production	**(175,206)**	(171,300)	(133,089)
Development	**(24,306)**	(28,731)	(39,000)
PGRT	**(114,361)**	(104,601)	(126,000)
Future pretax cash flows	**558,897**	550,240	519,806
Future income taxes	**(239,808)**	(243,535)	(237,241)
Future net cash flows	**319,089**	306,705	282,565
10% annual discount for estimated timing of cash flows	**(172,348)**	(153,986)	(151,658)
Discounted future net cash flows	**$ 146,741**	$ 152,719	$ 130,907

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year ended September 30,		
	1984	**1983**	**1982**
Revisions to reserves proved in prior years			
Revisions of previous quantity and timing estimates	**$ (8,310)**	$ 17,388	$ (30,304)
Net changes in prices, net of production costs and PGRT	**(3,323)**	29,738	106,713
Net changes in estimated future development costs	**(4,321)**	8,085	(9,798)
Other	**1,097**	857	1,118
Accretion of discount	**28,052**	23,266	16,705
	13,195	79,334	84,434
Changes during the year			
Extensions, discoveries and improved recovery, net of related costs	**34,468**	19,317	14,428
Previously estimated development costs incurred during the year	**8,845**	6,762	4,247
Sales of oil and gas produced, net of production costs and PGRT	**(65,221)**	(57,550)	(37,504)
	(21,908)	(31,471)	(18,829)
Total revisions and changes before income taxes	**(8,713)**	47,863	65,605
Net changes in income taxes	**2,735**	(26,051)	(36,828)
Total revisions and changes	**(5,978)**	21,812	28,777
Discounted future net cash flows, at beginning of year	**152,719**	130,907	102,130
Discounted future net cash flows, at end of year	**$ 146,741**	$ 152,719	$ 130,907

EFFECTS OF CHANGING PRICES

The following supplementary financial information is provided in accordance with the recommendations of the Canadian Institute of Chartered Accountants ("CICA"). Reference is made to "Proved Oil and Gas Reserve Quantities" presented on page 22. Although there are some differences in the presentation and certain calculations of current cost information required by the CICA and the Financial Accounting Standards Board of the United States, the objectives are similar.

Traditional financial reporting is based on transactions recorded at historic costs. There is general agreement that prolonged periods of significant inflation adversely affect the usefulness of information presented in historical cost financial statements. As a result, the CICA has begun a five-year experiment, to be reviewed before 1987, requiring the disclosure of certain supplemental current cost information designed to reflect the effect of changing prices.

The CICA method is an attempt to restate inventories, property, plant and equipment, cost of sales and depreciation and depletion expense into current values through the use of specific indices or known current costs.

The current cost of the Company's producing oil and gas property, plant and equipment has been estimated using the discounted future net cash flows as described in "Standardized Measure of Discounted Future Net Cash Flows and Changes Therein" presented on page 22. Current costs for non-producing properties are derived principally from current market information. Current cost estimates of other properties, plant and equipment have been largely developed by applying the Consumer Price Index to the historical cost of such assets. Historical depreciation and depletion has been adjusted to reflect the higher current cost of properties, plant and equipment. The Company has not restated inventory because of its relative insignificance.

Management cautions the reader regarding the interpretation and use of current cost information. While the Company has complied with the CICA requirements, and has exercised due care in developing such information, because of the subjective judgements involved, the results should be considered as only a broad indication of the effect of changing prices on the performance of the Company. The current cost estimates are not intended to represent appraised values or market selling prices for the assets, nor do they indicate the timing or the manner of actual replacement of assets.

Schedule of Effects of Changing Prices

	Year ended September 30, 1984
Net earnings on a historical cost basis	$ 24,898
Depletion and depreciation adjustment on a current cost basis	(5,097)
Net earnings on a current cost basis	19,801
Decrease in the current cost of property, plant and equipment held during the year	(11,818)
Net earnings on a current cost basis in nominal dollars	7,983
General purchasing power adjustments	
Increase in current cost of property, plant and equipment attributable to the effect of general inflation	9,151
Loss in general purchasing power from holding net monetary assets	1,415
	10,566
Net loss on a current cost basis in constant dollars	$ (2,583)

The provision for depreciation and depletion on a current cost basis is higher than the historical cost basis because the historical cost provision does not take into account the increased cost of replacing the Company's property, plant and equipment at current prices. The CICA current cost requirements do not include the adjustment of historical cost income taxes and interest expense. Without these adjustments the effective income tax rate is abnormally high and the effect of having long term debt at interest rates significantly above or below the prevailing interest rates is not reflected.

The general purchasing power of shareholders' equity is eroded by increases in general price levels. The increase in current cost of property, plant and equipment attributable to the effects of general inflation of $9,151,000 plus the general purchasing power loss from having net monetary assets of $1,415,000 provides a measure of this erosion.

The loss in general purchasing power from holding net monetary assets is calculated using the Consumer Price Index applied against the opening and closing net monetary assets expressed in average constant dollars. This loss represents the cost to the Company of being in a net monetary asset position during a period of inflation, as net future obligations to the Company would be discharged with dollars of declining purchasing power.

Schedule of Consolidated Assets on a Current Cost Basis

	September 30, 1984	
	Current cost basis	**Historical cost basis**
Property, plant and equipment	$233,909	$170,753
Net assets (shareholders' equity)	$207,103	$143,947

In periods of increasing prices the Company will require additional capital to offset the effect of increases in the specific prices of its property, plant and equipment. This is referred to as maintenance of the operating capability of the Company. The capital required to maintain the operating capability of the Company is provided by a combination of shareholders' funds and borrowed funds. The financing adjustment provides a measure of the increase in current cost amounts of that portion of property, plant and equipment which is financed by debt. Since the Company is in a net monetary asset position, the increase in the current cost of its property, plant and equipment is considered to be financed entirely with shareholders' funds. Therefore, no financing adjustment is required.

Auditors' Report

To the Shareholders of Scurry-Rainbow Oil Limited

We have examined the consolidated balance sheets of Scurry-Rainbow Oil Limited as at September 30, 1984 and 1983 and the consolidated statements of earnings and retained earnings and changes in financial position for each of the three years in the period ended September 30, 1984. Our examinations were made in accordance with generally accepted auditing standards in Canada, 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 September 30, 1984 and 1983 and the results of its operations and the changes in its financial position for each of the three years in the period ended September 30, 1984 in accordance with generally accepted accounting principles in Canada, consistently applied.

Price Waterhouse

Chartered Accountants

Calgary, Alberta, Canada.
November 16, 1984.

Five-Year Financial Review

	Year ended September 30, 1984	1983	1982	1981	Nine months ended September 30, 1980
Financial					
(Expressed in thousands except per share amounts)					
Revenue					
Crude oil	**$ 67,356**	$ 57,056	$ 40,727	$ 30,106	$ 18,586
Natural gas	**18,722**	17,943	12,503	10,449	7,784
Natural gas liquids	**3,036**	2,599	1,406	1,202	835
Sulphur	**1,317**	1,381	1,149	2,258	1,189
Mining	**—**	—	310	7,731	15,150
Other	**4,989**	3,110	479	891	747
	95,420	82,089	56,574	52,637	44,291
Expense					
Operating and general	**15,750**	14,437	14,144	22,179	15,605
Depletion and depreciation	**15,715**	15,029	9,713	9,111	6,661
Other	**877**	783	2,099	3,413	2,379
	32,342	30,249	25,956	34,703	24,645
Earnings before taxes and extraordinary item	**63,078**	51,840	30,618	17,934	19,646
Taxes	**38,180**	29,377	16,294	9,352	6,444
Extraordinary item	**—**	—	—	—	2,585
Net earnings	**$ 24,898**	$ 22,463	$ 14,324	$ 8,582	$ 15,787
Earnings per share	**$ 1.86**	$ 1.68	$ 1.07	$ 0.64	$ 1.18
Funds generated from operations	**$ 61,681**	$ 52,554	$ 29,609	$ 21,552	$ 26,945
Per share	**$ 4.61**	$ 3.92	$ 2.21	$ 1.61	$ 2.01
Working capital (deficiency)	**$ 53,877**	$ 35,688	$ (957)	$ (4,618)	$ 3,724
Total assets	**$ 256,600**	$ 211,535	$ 177,412	$ 153,112	$ 147,204
Long term debt (including current portion)	**$ 6,897**	$ 7,720	$ 9,417	$ 15,908	$ 25,212
Shareholders' equity	**$ 143,947**	$ 119,049	$ 96,586	$ 82,262	$ 73,680
Capital expenditures, after PIP grants					
Oil and gas					
Land acquisition	**$ 4,421**	$ 773	$ —	$ 1,407	$ 383
Exploration	**23,194**	9,760	3,594	2,476	7,292
Development	**17,438**	9,355	15,325	13,771	15,739
Mining	**44**	213	1,692	3,752	2,159
Other	**95**	102	106	261	93
	$ 45,192	$ 20,203	$ 20,717	$ 21,667	$ 25,666
Shares outstanding at end of period	**13,391,780**	13,391,780	13,391,780	13,391,780	13,391,780

The above data incorporates retroactive adjustments

Five-Year Operating Review

	1984	1983	1982	1981	1980
	Year ended September 30,				Nine months ended September 30,
Production/Sales (before royalties)					
Crude oil production					
— barrels per day	**7,304**	7,227	6,460	7,070	7,086
— cubic metres per day	**1 161**	1 150	1 027	1 124	1 126
Natural gas liquids sales					
— barrels per day	**405**	371	264	253	254
— cubic metres per day	**64**	59	42	40	40
Natural gas sales					
— thousands of cubic feet per day	**21,711**	20,622	16,824	16,593	17,676
— thousands of cubic metres per day	**612**	581	474	467	498
Sulphur sales					
— long tons per day	**67**	62	53	90	97
— tonnes per day	**68**	63	54	92	99
Drilling Activity					
Gross wells drilled	**318**	70	54	70	72
Working interest	**272**	53	42	47	46
Royalty interest	**46**	17	12	23	26
Net wells drilled	**31.16**	11.93	15.07	10.79	11.08
Oil	**20.88**	8.07	6.77	5.84	6.43
Gas	**2.84**	0.50	2.34	2.30	2.13
Proved Reserves (before royalties)					
Crude oil					
— thousands of barrels	**17,203**	15,945	17,259	21,847	19,254
— thousands of cubic metres	**2 735**	2 535	2 744	3 476	3 061
Natural gas liquids					
— thousands of barrels	**1,975**	1,610	1,686	2,937	1,555
— thousands of cubic metres	**314**	256	268	467	247
Natural gas					
— billions of cubic feet	**192.8**	178.9	169.0	183.1	174.6
— millions of cubic metres	**5 432**	5 040	4 761	5 159	4 918
Sulphur					
— thousands of long tons	**340.7**	366.9	366.0	581.5	456.6
— thousands of tonnes	**346.2**	372.9	372.0	591.0	464.0
Landholdings					
Oil and gas					
Gross undeveloped					
— thousands of acres	**3,388**	3,561	4,054	4,369	5,644
— thousands of hectares	**1 372**	1 442	1 641	1 769	2 285
Net undeveloped					
— thousands of acres	**1,072**	1,350	1,395	1,550	1,676
— thousands of hectares	**434**	547	565	628	679
Gross developed					
— thousands of acres	**776**	730	739	683	492
— thousands of hectares	**314**	296	299	277	199
Net developed					
— thousands of acres	**131**	124	126	131	102
— thousands of hectares	**53**	50	51	53	41
Mining					
Gross undeveloped					
— thousands of acres	**160**	163	462	672	773
— thousands of hectares	**65**	66	187	272	313
Net undeveloped					
— thousands of acres	**74**	77	173	217	249
— thousands of hectares	**30**	31	70	88	101

Corporate Information

Board of Directors

\+ **Robert G. Black,** Q.C., Calgary, Alberta
Barrister and Solicitor

Richard F. Haskayne, Calgary, Alberta
President and Chief Executive Officer of Home Oil Company Limited
President and Chief Executive Officer of the Company

\+ **J. Gordon Hutchison,** F.C.A., Calgary, Alberta
Financial Consultant

\+ **John F. Langston,** Calgary, Alberta
Petroleum Engineer

Brian F. MacNeill, Calgary, Alberta
Vice President Finance of Home Oil Company Limited
Vice President Finance of the Company

Stanley G. Olson, Spokane, Washington
Corporate Director

David E. Powell, Calgary, Alberta
Senior Vice President Exploration of Home Oil Company Limited
Senior Vice President Exploration of the Company

William P. Wilder, Toronto, Ontario
Chairman of the Board of The Consumers' Gas Company Ltd. and Director of Hiram Walker Resources Ltd.

\+ Member of Audit Committee

Senior Officers

R. F. Haskayne
President and Chief Executive Officer

D. E. Powell
Senior Vice President Exploration

H. Alfaro
Vice President Production

F. Callaway
Vice President Corporate Affairs

B. F. MacNeill
Vice President Finance and Chief Financial Officer

K. A. McNeill
Vice President Administration

R. G. Watkins
Vice President Government and Industry Relations

D. E. Deakin
Corporate Secretary

A.R. Hagerman
Treasurer

E. Jorgensen
Comptroller

Auditors

Price Waterhouse
Calgary, Alberta, Canada

Registrar and Transfer Agents

Guaranty Trust Company of Canada
Calgary, Toronto, Montreal, Vancouver

The Canadian Imperial Bank of Commerce Trust Company
New York, N.Y.

Stock Exchange Listings Symbols

Toronto Stock Exchange	SCR
American Stock Exchange	SRB

Principal Affiliates

Plains Petroleums Limited (72.2 percent)
Minerals Limited (50.0 percent)

Principal Affiliate Offices

Plains Petroleums Limited
1700 Home Oil Tower
324 Eighth Avenue S.W.
Calgary, Alberta, Canada
T2P 2Z5

Minerals Limited
150 - 9 Avenue S.W.
Calgary, Alberta, Canada
T2P 3H9

Common Shares

At September 30, 1984, the Company had 13,391,780 common shares issued and outstanding, held by 3,384 shareholders. To date, the Company has not authorized the payment of dividends on the common shares.

The Foreign Investment Review Act ("FIRA") requires prior approval by the Government of Canada of the acquisition by or the transfer to nonresidents of Canada of direct or indirect control of a Canadian business entity, such as Scurry-Rainbow Oil Limited. FIRA does not apply to the purchase of shares or securities of a corporation for investment purposes where such purchase would not give the buyer(s) effective control of the corporation.

	Prices			
	Toronto Stock Exchange (Cdn. dollars)		American Stock Exchange (U.S. dollars)	
	High	Low	High	Low
Year ended September 30, 1984				
1st quarter	19¾	16½	16¼	13⅛
2nd quarter	20	17⅞	16⅞	14¼
3rd quarter	19½	17	15⅛	12⅞
4th quarter	18¾	14½	14½	11
Year ended September 30, 1983*				
1st quarter	13¼	9⅝	10⅝	7¾
2nd quarter	12	10	10¼	8
3rd quarter	17⅜	9¾	14	7⅞
4th quarter	24½	16⅞	19⅞	15⅛

* Prices adjusted to reflect 5 for 1 share split which became effective July 5, 1983.

SCURRY-RAINBOW OIL LIMITED
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SCURRY-
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