SCURRY-RAINBOW OIL LIMITED ANNUAL REPORT 1983

Scurry-Rainbow Oil Limited

Corporate Profile
Scurry-Rainbow Oil Limited 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 development and production of crude oil and natural gas. Exploration activities are conducted in Alberta, British Columbia, Saskatchewan, the Beaufort Sea, offshore Nova Scotia and in the Netherlands' sector of the North Sea. The major producing properties are located in the three western provinces. The Company owns substantial undeveloped coal reserves in southern Alberta and British Columbia and holds a net profits interest in a producing gold and silver mine in Nevada.

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

The Company has a Canadian Ownership Rate of 83 percent and is Canadian controlled. This qualifies the Company for the maximum level of Petroleum Incentives Program ("PIP") grants under the National Energy Program.

Annual General Meeting
The Annual General Meeting of Shareholders will be held on Monday, February 6, 1984 at 10:30 a.m. in the Company's head office, 29th floor, 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 United States Securities and Exchange Commission 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 E. Jorgensen, Comptroller, Scurry-Rainbow Oil Limited, 2300 Home Oil Tower, 324 Eighth Avenue S.W., Calgary, Alberta, Canada, T2P 2Z5.

Contents

Highlights

	Year ended September 30,		
	1983	**1982**	**1981**
Financial (Thousands of Dollars)			
Revenue	**82,089**	56,574	52,637
Net earnings	**22,463**	14,324	8,582
Funds generated from operations	**52,554**	29,609	21,552
Government royalties and taxes payable	**49,237**	30,240	22,628
Capital expenditures (before PIP grants)	**43,170**	24,957	24,973
Capital expenditures (after PIP grants)	**20,203**	20,717	21,667
Working capital (deficiency)	**35,688**	(957)	(4,618)
Per Common Share (Dollars)			
Net earnings	**1.68**	1.07	0.64
Funds generated from operations	**3.92**	2.21	1.61
Operating			
Daily Average Production (before royalties)			
Crude oil & natural gas liquids (barrels)	**7,598**	6,724	7,323
Natural gas (thousands of cubic feet)	**20,622**	16,824	16,593
Proved Reserves (before royalties)			
Crude oil & natural gas liquids (millions of barrels)	**17.6**	18.9	24.8
Natural gas (billions of cubic feet)	**179**	169	183
Sulphur (thousands of long tons)	**367**	366	582
Acreage			
Oil & gas (thousands of net acres)	**1,477**	1,521	1,681

The financial data were restated to reflect the five for one share split (effective July 5, 1983) and the change in accounting policy (note 2, page 18).

Glomar Labrador I drilling the Louisbourg well on the Scotian Shelf.

To The Shareholders

Financial Results

1983 was the most successful year in the Company's history. Net earnings for the year ended September 30, 1983 were $22.5 million or $1.68 per share, an increase of 57 percent from restated net earnings for 1982. Funds generated from operations rose by 77 percent to $52.6 million or $3.92 per share. Revenues, net of royalties, amounted to $82.1 million, an increase of 45 percent. These substantial increases resulted from higher production volumes and higher prices for oil and gas. Capital expenditures, before PIP grants, totalled $43.2 million in 1983, an increase of 73 percent, principally because of substantial commitments in the frontier areas of Canada. After deducting PIP grants, expenditures totalled $20.2 million, essentially unchanged from the net amount spent during the previous year.

Oil and Gas

The most important developments during the year were two major farmins on lands owned by Dome Petroleum Limited ("Dome") in Western Canada and in the frontier areas. The farmin agreements cover more than 33 million gross acres (15 million net) and commit the Company to capital expenditures in excess of $160 million, before PIP grants, over the next three years. The lands in Western Canada provide the opportunity for early production growth and the frontier regions offer excellent exploration and production potential over the long term.

Drilling activity increased by 26 percent during the year because of the farmin agreements, with the Company participating in 53 working interest wells. Crude oil and natural gas liquids production, before royalties, averaged 7,598 barrels per day in 1983, up 13 percent from the prior year. Improved performance from the Eagle fields in British Columbia as well as improved market conditions for production in Saskatchewan were the major contributing factors. Natural gas sales, before royalties, rose by 23 percent to 20.6 million cubic feet per day, due to the start-up of the South Wapiti field, and increased sales from the Karr field.

Industry Outlook

During 1983, the federal and provincial governments continued to respond to the difficulties being experienced by the Canadian petroleum industry. By virtue of amended energy agreements on pricing, approximately 25 percent of the industry's conventional crude oil production now receives the equivalent of the world price, compared with about 5 percent a year ago. Furthermore, the price for the remaining production was frozen at a minimum of $29.75 per barrel or roughly 80 percent of the current world price. In an effort to encourage additional sales of natural gas, the federal government cut the price of exports to the United States from U.S. $4.94 per thousand cubic feet to U.S. $4.40 per thousand cubic feet and introduced a volume-related incentive price of U.S. $3.40 per thousand cubic feet. The federal and provincial governments are continuing to examine a number of additional incentives to increase both export and domestic gas sales.

The Government of Saskatchewan, under its Oil Industry Recovery Program, extended the royalty holiday available to new oil wells for two more years to December 31, 1985. The royalty holidays, lower royalties and higher prices available under the Program have stimulated a severalfold increase in Saskatchewan exploration activities which is expected to continue in 1984. As part of Alberta's ongoing incentives, the government renewed the Well Servicing Incentive Program and the Development Drilling Incentive System. These two programs provided cash grants and both expired during the last two months of fiscal 1983. The government also decided to significantly reduce the Alberta Royalty Tax Credit from 75 percent to 50 percent with a $2 million maximum, effective January 1, 1984.

On balance, the actions of governments in 1983 helped improve the industry's cash flow and encouraged increased activity.

The most pressing problem currently facing the industry is the weak demand for natural gas, particularly in the export market where sales in 1983 were less than one-half of authorized volumes. Although a return to normal seasonal weather patterns will improve the situation, a major market turnaround is not expected for some time.

Corporate Outlook

During 1984, declining production in the West Eagle field and in a number of mature, non-operated fields will be largely offset by recent successes in the same general areas, the further lifting of market constraints in Saskatchewan and successful exploratory drilling. Due to an anticipated lack of demand, gas sales will likely remain at about the same level as 1983, although the Company has the productive capacity to expand sales significantly when markets improve.

The average wellhead price for crude oil will increase slightly due to the full year's impact of reclassifying the Special Old Oil Price to the New Oil Reference Price, which affected a large proportion of Scurry-Rainbow's production. Natural gas prices will remain essentially unchanged, because increases in the domestic field price will be offset by reductions in the export flowback.

With an increasing proportion of natural gas liquids production coming from Crown lands, average royalty rates on natural gas liquids will increase. The Company's tax expense will increase beginning January 1, 1984, by the scheduled reduction in the Alberta Royalty Tax Credit.

Capital expenditures planned for 1984 are expected to increase significantly to approximately $90 million, before PIP grants. The exploration program, which will be the largest in the history of the Company, will consume more than three-quarters of total expenditures and is aimed at the discovery of oil in Western Canada where there is the prospect of early cash flow. At the same time, major exploration programs will continue in the frontier regions where there is the potential for much larger discoveries, but where production will not commence for a number of years.

Scurry-Rainbow's development program is designed to optimize recoveries from existing fields, drill in areas qualifying for the New Oil Reference Price, reduce operating costs and improve the efficiency of the Company's facilities.

Corporate Changes

On July 4, 1983, the shareholders approved a five for one share split of the authorized 7.5 million common shares, an increase in the authorized common share capital to 200 million shares, creation of 100 million preferred shares and continuance of the Company under the Business Corporations Act of Alberta. The changes to the capital structure and the continuance became effective July 5, 1983.

Since the last annual report to shareholders, D.E. Powell was appointed Senior Vice President Exploration and Director of the Company, replacing W.H. Waddell.

Submitted on behalf of the Board of Directors.

R. P. Hashugne

Calgary, Alberta, Canada
November 25, 1983

President and Chief
Executive Officer

Review of Operations

Exploration and Development

Drilling Activity

During 1983, the Company participated, through working interests, in nine exploratory wells and 44 development wells, an increase of 26 percent compared with 1982. Three of the exploratory wells and 19 of the development wells were related to the farmin on Dome lands.

Exploratory drilling resulted in four oil wells and one gas well. Two of the oil wells and the one gas well were located in Alberta; the remaining two oil wells were in Saskatchewan. In addition, four wells in the Beaufort Sea were suspended and will be drilled to total depth and tested during the 1984 drilling season.

Development drilling resulted in the completion of 28 oil wells and seven gas wells. Fourteen of the oil wells and the seven gas wells were in Alberta, nine of the oil wells were in British Columbia and the remaining five oil wells were in Saskatchewan.

Working Interest Wells[1]

	1983		1982	
	Gross	Net	Gross	Net
Exploratory				
Oil	4	1.20	2	0.28
Gas	1	0.08	1	0.67
Dry	4	1.49	4	0.49
Total	9	2.77	7	1.44
Development				
Oil	28	6.87	15	6.49
Gas	7	0.42	12	1.67
Dry	9	1.87	8	5.47
Total	44	9.16	35	13.63
Total[2]	53	11.93	42	15.07

[1] The heading "gross" refers to the number of wells in which the Company has a working interest. "Net" represents the total of the working interests held in each of the gross wells. The table does not include suspended wells or wells that were still drilling at year-end.

[2] In addition to these interests, the Company holds gross overriding royalty positions in nine new oil wells and one new gas well as at September 30, 1983.

Major Farmins

The most significant step taken by Scurry-Rainbow over the past year was the participation, through the Company's affiliation with Home, in two farmin agreements on lands owned by Dome in Western Canada, the Beaufort Sea, offshore Nova Scotia and the Arctic Islands.

In July 1983, Scurry-Rainbow agreed to participate in a three-year farmin agreement on about 20 million gross acres (10 million net) of Dome's lands in Western Canada and 12.8 million gross acres (5 million net) in the Beaufort Sea.

In Western Canada, the Company will pay 13.34 percent of Dome's exploration and development costs to earn a 6.67 percent working interest in a maximum of nine sections surrounding each exploratory well, and in the spacing unit containing each development well. During the three-year term of the agreement, Scurry-Rainbow is committed to spend a minimum of $55 million before PIP grants. The Company also may extend the agreement by one year.

Through this farmin, Scurry-Rainbow gains access to the largest spread of acreage held by any company in Western Canada. The move should allow the Company to participate in most industry plays over the next three years. Between early July and September 30, 1983, Scurry-Rainbow participated in drilling 22 wells on Dome lands in Western Canada, resulting in 12 oil wells and four gas wells.

In the Beaufort Sea, Scurry-Rainbow agreed to spend during the three years a minimum of $59 million, or $12 million after PIP grants. This represents the Company's share of well costs, which will vary between 5.00 percent and 11.67 percent, in a six-well program. Scurry-Rainbow will earn between 2.50 percent and 5.83 percent of Dome's interest in the structures drilled, and an approximate 1.5 percent interest in the remaining undrilled lands, excluding significant prior discoveries.

As part of the six-well program, the Siulik I-05 and Arluk E-90 wells were spudded and drilled to depths of 13,350 feet and 11,300 feet, respectively, before being suspended due to unusually severe ice conditions. Scurry-Rainbow will earn a 4.2 percent interest in Siulik and a 4.9 percent interest in Arluk and expects both wells will be tested next year.

The Beaufort Sea agreement was also structured so that the Company retained the 20 percent interest already held in the 607,000 gross acres where the Natiak O-44 and Havik B-41 wells are being drilled by Dome. During the 1983 drilling season, the Natiak well was re-entered and drilled to a depth of 12,000 feet, but evaluation of the well will be delayed until the next season because of unfavorable ice conditions. The Havik well was spudded and drilled to 2,300 feet before operations were suspended due to encroaching pack ice. The Company holds a 20 percent interest in each well and the expenditures associated with these two wells will be approximately $49 million, or $10 million after PIP grants.

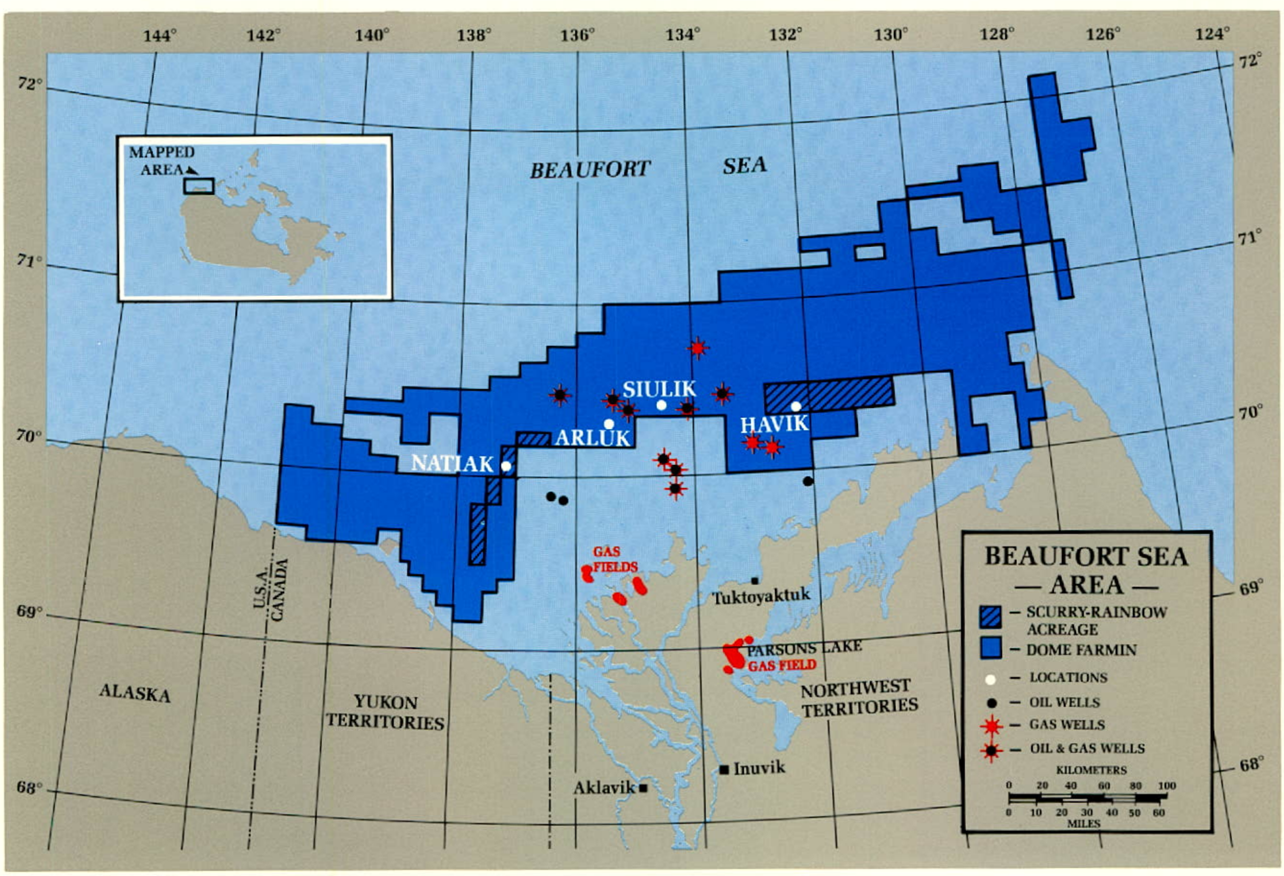
In April 1983, Scurry-Rainbow agreed to participate in a farmin agreement covering Dome lands on the East Coast and in the Arctic Islands.

Offshore Nova Scotia, the Company will earn a 7.3 percent interest in a structure located on the 593,000 acre East Sable block. The well, Louisbourg J-47, was spudded on November 25. Scurry-Rainbow's share of the cost is estimated at $7.3 million, or $1.5 million after PIP grants.

The Explorer III drillship on location at the Havik well site in the Beaufort Sea.

Scurry-Rainbow also holds an option to participate in a maximum of two additional wells to earn an identical interest in other structures on the East Sable block. Home is the Operator of this drilling program with each well expected to cost approximately $50 million, before PIP grants.

The Louisbourg well will take roughly 200 days to drill to its total depth of 21,000 feet. An additional 50 to 60 days is expected for completion and testing. The well will be drilled



in about 220 feet of water using the new Global Marine Labrador I jack-up rig, one of the largest in the world. The objective of the Louisbourg well is natural gas and condensate.

In the Arctic Islands, the Company will earn a 3.7 percent interest in the deep rights of a structure currently being drilled on the Sabine Peninsula block. The Company has an option to participate in two additional wells on this block. Scurry-Rainbow relinquished an option to participate with Dome in a well at Cape Allison, which is also in the Arctic Islands.

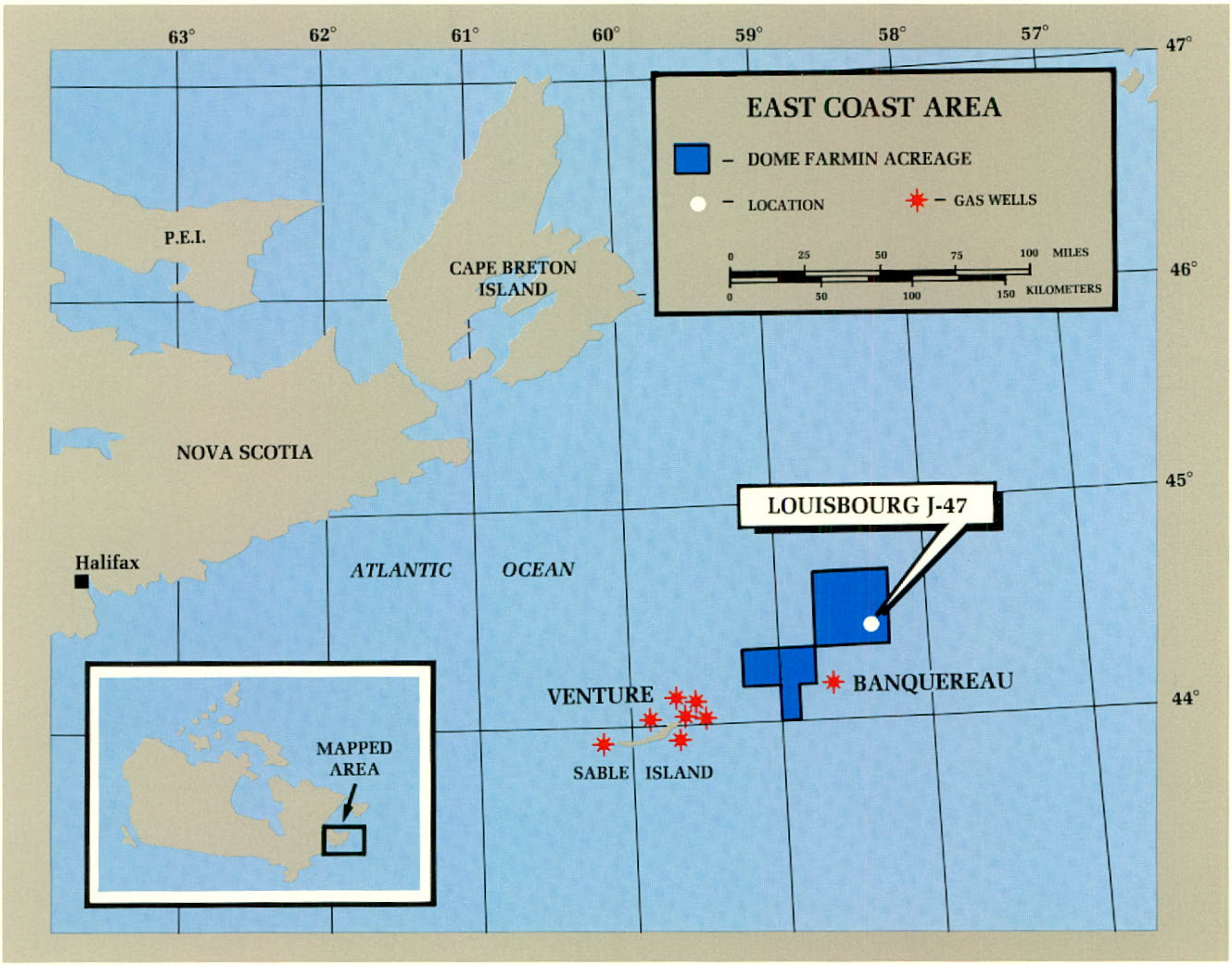
British Columbia

During 1983, Scurry-Rainbow participated in three unsuccessful exploratory wells, and 13 development wells, none of which were related to the farmin on Dome lands. Development drilling resulted in nine oil wells.

The Company was the Operator of eight development wells drilled in the Fort St. John area. This resulted in six oil wells from which Scurry-Rainbow's share of production is expected to exceed 200 barrels of oil per day. In addition, the Company holds an average interest of 5.6 percent in three development oil wells at Boundary Lake northeast of Fort St. John.

At West Eagle Unit No. 1, the Company's most important field where it has a 31.5 percent interest, a comprehensive geological and waterflood performance study was completed near mid-year. The study indicated the need for four new in-fill wells and conversion of several production wells to injector wells. The Company received tentative approval for this program from its associates in Unit No. 1 and is currently awaiting approval from the provincial government.

Battery facilities were completed in the Cecil field and are now capable of handling 365 barrels of oil and 3.5 million cubic feet of gas per day.



The water injection plant at West Eagle Unit No. 1.

Alberta

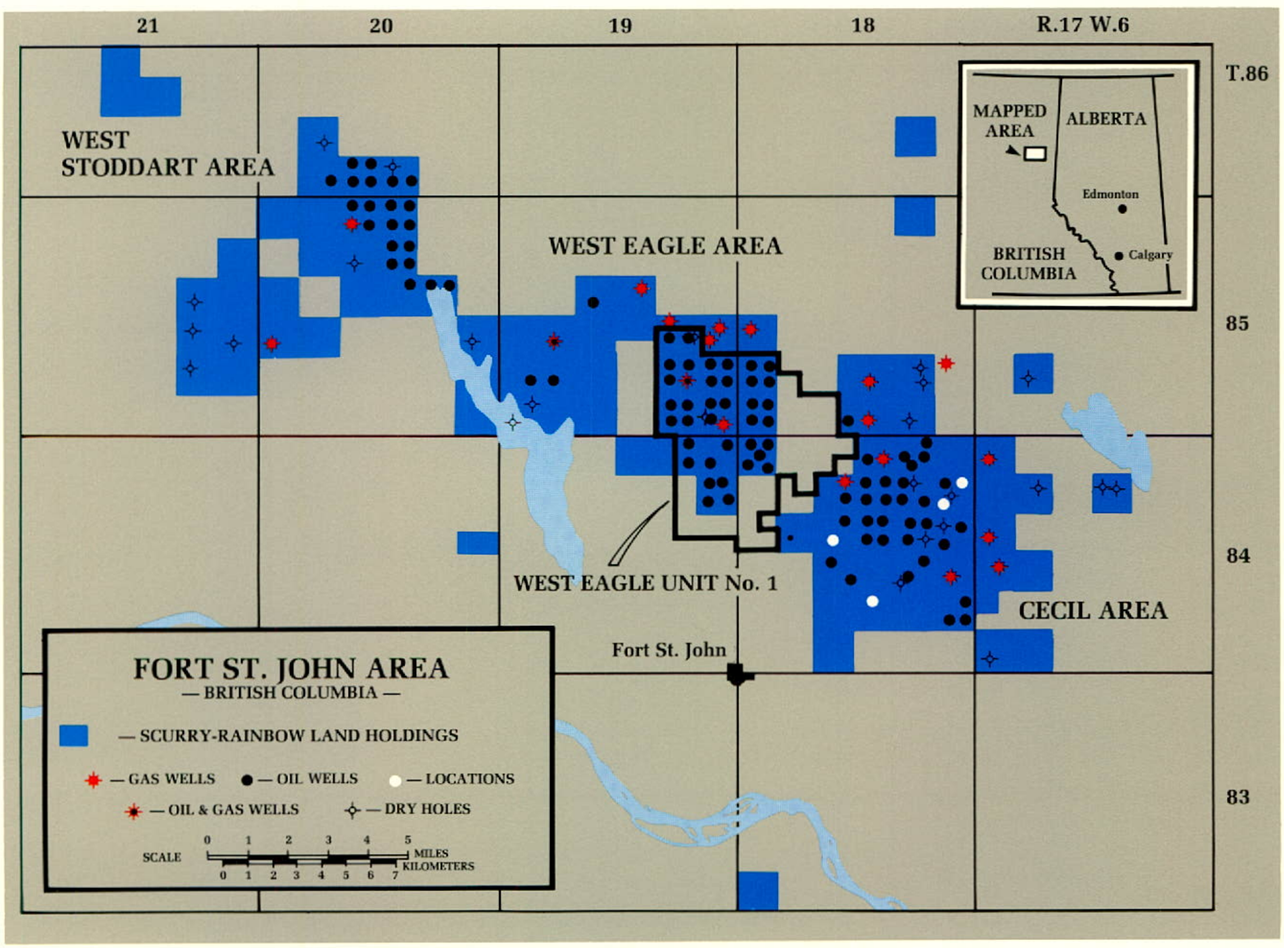
The Company held a working interest in four exploratory and 25 development wells drilled in Alberta during the year. Participation in two of the exploratory wells and in 17 of the development wells arose from the farmin on Dome lands. Exploratory drilling resulted in two oil wells and one gas well. The results of the development drilling program were 14 oil wells and seven gas wells.

Two of the development wells farmed out by Dome in north-central Alberta were potentially significant oil finds. Scurry-Rainbow holds a 1.17 percent interest in the well at Valhalla and a 3.08 percent interest in the other well at Tangent. Although the interests are small, the Company holds the option to earn interests in a substantial amount of additional land in the two areas. Initial testing of both wells was very encouraging and further drilling is planned.

By virtue of the Company's interest in 11 connected gas wells in the south and central blocks of the South Wapiti field, Scurry-Rainbow became a 9.65 percent owner in the new South Wapiti gas processing plant. In addition, the Company acquired interests in the gas gathering system and compression facilities.

Saskatchewan

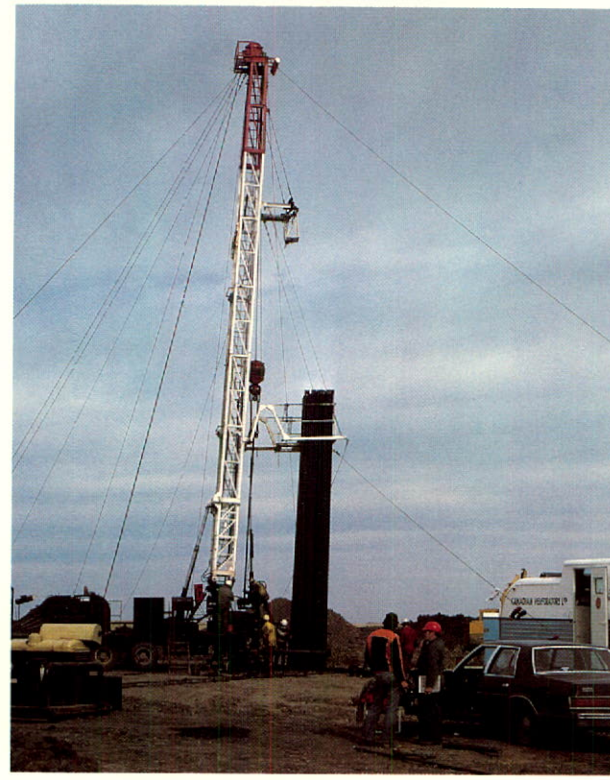
Following changes to the province's royalty and taxation system in 1982, the Company reactivated



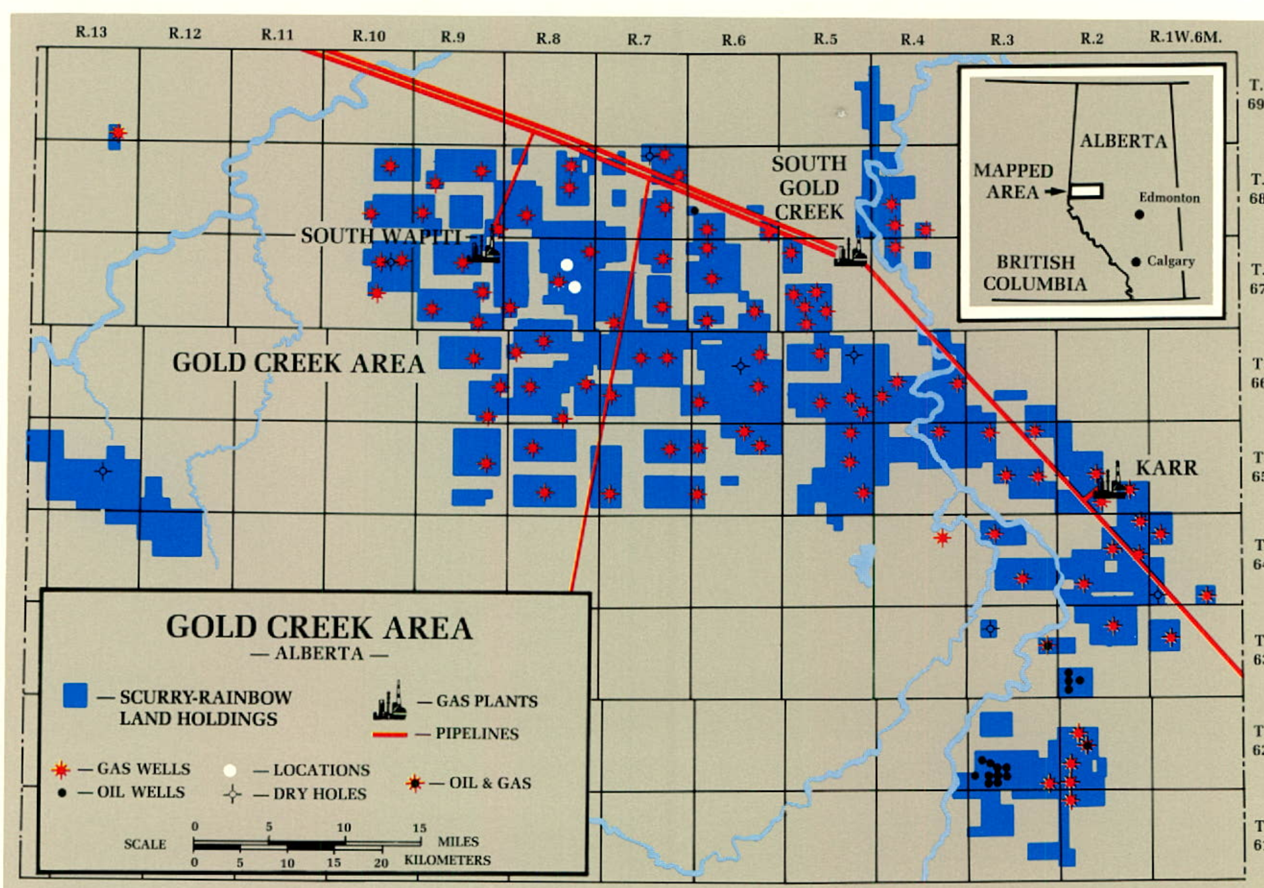
exploratory and development activities on its existing acreage and became an active purchaser at Crown land sales. During 1983, Scurry-Rainbow drilled two exploratory and six development wells. One of the exploratory wells and two of the development wells were in conjunction with the farmin on Dome lands.

Both exploratory wells discovered oil. One of these wells, 100 percent-owned by the Company, was drilled at Tableland in southeastern Saskatchewan and appears to be capable of producing oil at a significant rate. Five of the development wells were also successfully completed as oil producers in the southeastern part of the province.

In February, Scurry-Rainbow farmed out approximately 40,000 net acres in southeastern Saskatchewan to Bedford Petroleums Limited and Postell Energy Co. Ltd. These companies plan to drill 40 wells before December 31, 1984 in order to earn all of Scurry-Rainbow's working interests in the spacing units upon which the wells are drilled. The first three wells were spudded in mid-November and 12 additional wells are



A service rig working on the Tableland well.



expected to be completed by December 31, 1983. Bedford and Postell also have options to drill another 60 wells before April 30, 1987 under the same terms and conditions.

Scurry-Rainbow will retain gross overriding interests in the farmout ranging between 5 percent and 30 percent, depending upon the rates of production and whether the leases are freehold or Crown. The lands farmed out are small, isolated properties more effectively drilled and developed by smaller companies having considerable operating experience in this region.

Other

During the summer, a gross overriding royalty well was drilled at no cost to Scurry-Rainbow on the Company's lands in the Netherlands' sector of the North Sea. The well produced 32 million cubic feet of gas during testing. An additional exploratory well may be drilled in 1984. This North Sea permit covers approximately 105,000 acres and the Company holds a 1.53 percent interest. In March of 1983, Scurry-Rainbow relinquished another permit in the North Sea covering about 51,000 acres in which the Company held a 2.49 percent interest.

In the second fiscal quarter of 1983, Westcoast Oil and Gas Corp., a wholly-owned subsidiary, sold its oil and gas assets in the United States to HPC, Inc., wholly-owned by Hiram Walker Resources Ltd. The price of approximately $1.1 million was based on an evaluation of the properties by outside engineering consultants. With this sale, the Company has no oil and gas interests in the United States.

Mining

Scurry-Rainbow completed the sale of the Gooseberry mine to Asamera, Inc. on January 10, 1983. At the Closing, the Company received U.S. $3 million and will receive a further U.S. $6 million in equal, annual payments for the next ten years commencing January 31, 1984. The Company also retained a net profits interest of 15 percent at gold prices up to U.S. $650 per ounce, 25 percent at gold prices over U.S. $650 per ounce and 30 percent at gold prices over U.S. $1,000 per ounce. The mine was started up again late in May and is now processing between 250 and 300 tons of ore per day.

Oil and Gas Acreage[1]

	Gross	Net
Canada		
Saskatchewan	784,966	713,274
Alberta	1,205,532	235,384
Beaufort Sea	606,744	121,349
Arctic Islands	681,546	81,614
British Columbia	347,576	78,614
Other	559,700	241,882
	4,186,064	1,472,117
Foreign		
Netherlands Offshore	104,770	1,604
Total acreage at September 30, 1983[2]	4,290,834	1,473,721
Total acreage at September 30, 1982[2]	4,793,008	1,521,272

[1] "Gross acres" refers to the total number of acres in which Scurry-Rainbow holds either a working interest or an overriding royalty interest. "Net acres" are 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.

[2] The table includes 730,226 (September 30, 1982 — 739,329) gross acres and 123,825 (September 30, 1982 — 126,227) net acres of developed lands in the western provinces.

Production

During 1983, crude oil and natural gas liquids production, before royalties, averaged 7,598 barrels per day compared with 6,724 barrels per day in 1982. The major factors contributing to this 13 percent increase were the continued improvement in the performance of four oil fields near the Fort St. John area in British Columbia and improved markets for production from Saskatchewan.

The four fields in the Fort St. John area represent the Company's major oil producing properties. The Eagle, West Eagle, Cecil and West Stoddart oil fields were placed on-stream a number of years ago and currently account for over 45 percent of Scurry-Rainbow's total oil production. Most of this oil now qualifies for the New Oil Reference Price.

At West Eagle Unit No. 1, crude oil production increased by 7 percent to 2,588 barrels per day. This was due to an improved waterflood response in the central portion of the reservoir, placing six wells back on production and installing artificial lift facilities on four wells.

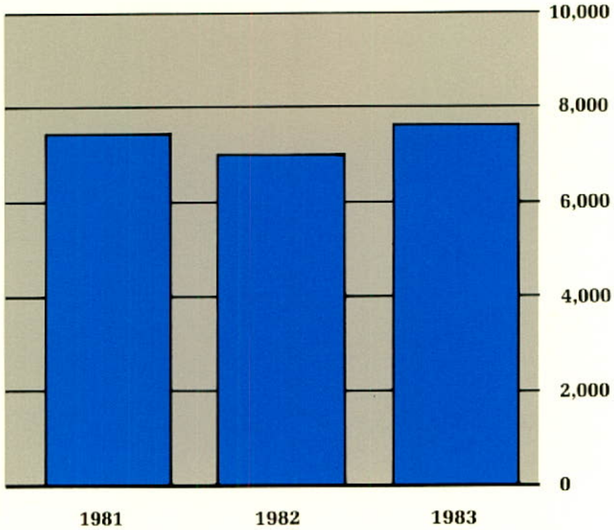
With improved markets, oil production in Saskatchewan rose by 36 percent to 1,841 barrels per day, primarily because of increased production from the Workman Frobisher Unit.

Currently about 52 percent of Scurry-Rainbow's crude oil production qualifies for the New Oil Reference Price, which is more than double the overall industry average of 25 percent for conventional crude oil.

Average natural gas sales, before royalties, increased by 23 percent to approximately 20.6 million cubic feet per day, due to new sales from the South Wapiti gas field and increased sales from the Karr gas field; both of which are located in the Gold Creek area of Alberta.

Production from South Wapiti began on December 15, 1982, with the Company's share averaging 16 million cubic feet per day until March 31, 1983. At that time, the 1983 contract volumes had been largely fulfilled and production was shut-in for essentially the remainder of the year. Production from the field resumed on November 1, 1983, the start of the new contract year, at relatively low nomination rates. The royalty free period, to which a portion of the sales from this field are entitled, will continue through 1984.

AVERAGE DAILY PRODUCTION
OIL & GAS LIQUIDS
BARRELS



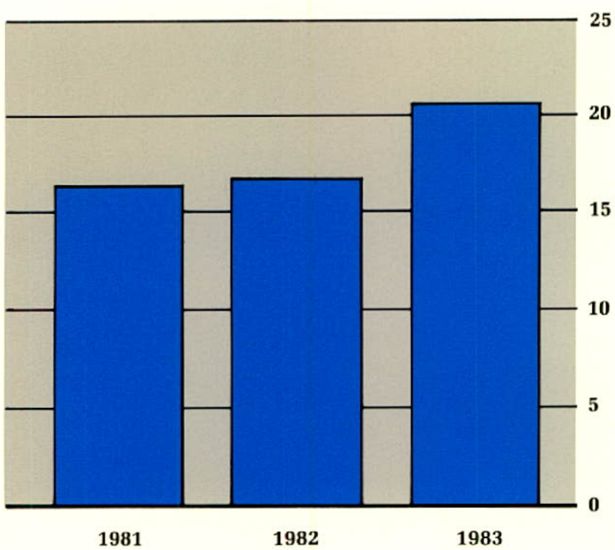
Between November 1, 1982 and March 31, 1983, the annual contract volumes from the Karr area were largely fulfilled and the gas processing plant was shut-in, except for intermittent periods, until the new contract year commenced on November 1, 1983. By March 31, 1983, the Company's share of sales from the Karr field had averaged 3.4 million cubic feet of gas per day.

Daily Average Production
(Before Royalties and Minority Interests)

	1983		1982	
	Petroleum Liquids[1]	Natural Gas	Petroleum Liquids[1]	Natural Gas
	(barrels)	(thousands of cubic feet)	(barrels)	(thousands of cubic feet)
Alberta	1,455	16,732	1,329	12,249
British Columbia	4,200	3,403	3,915	4,438
Saskatchewan	1,841	457	1,357	129
Other	102	30	123	8
Total	7,598	20,622	6,724	16,824

[1] Includes crude oil and natural gas liquids

AVERAGE DAILY SALES
NATURAL GAS
MILLIONS OF CUBIC FEET



Proved Reserves

The Company added nearly 1.5 million barrels of crude oil reserves during 1983, primarily from fields in the Fort St. John area, replacing more than 50 percent of the 2.6 million barrels produced. Natural gas reserves increased by 6 percent because additions from development drilling in the Karr field and upward revisions at South Wapiti resulting from improved reservoir performance, more than offset production.

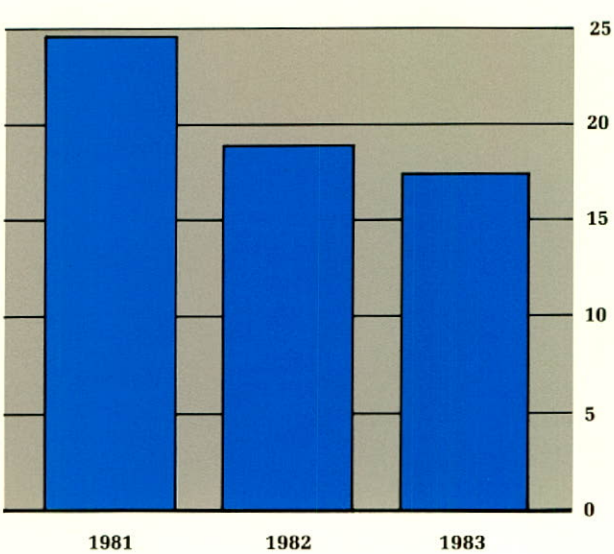
Sulphur reserves increased marginally due to net upward revisions at Coleman.

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 economically recoverable in future years from known reservoirs under existing operating and economic conditions. The reserve estimates are prepared by Company engineers.

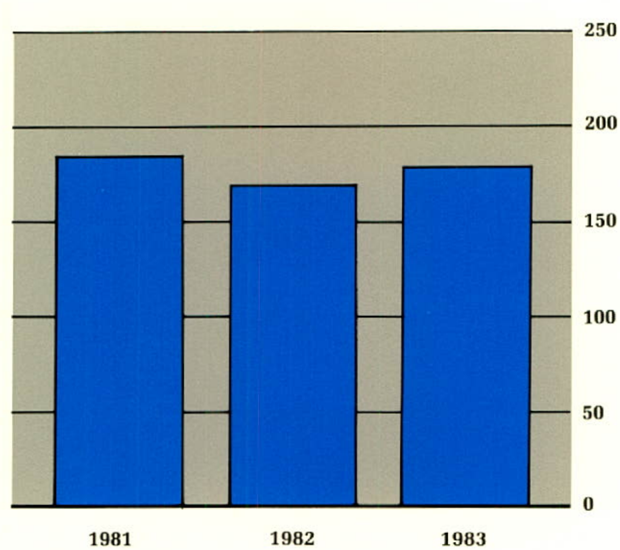
Proved Reserves
(Before Royalties and Minority Interests)

	Crude Oil (thousands of barrels)	Natural Gas Liquids (thousands of barrels)	Natural Gas (billions of cubic feet)	Sulphur (thousands of long tons)
October 1, 1982	17,259	1,686	169.0	366.0
Additions	1,472	—	4.1	—
Revisions	(148)	59	13.3	23.7
Production	(2,638)	(135)	(7.5)	(22.8)
September 30, 1983	15,945	1,610	178.9	366.9

PROVED RESERVES
OIL & GAS LIQUIDS
MILLIONS OF BARRELS



PROVED RESERVES
NATURAL GAS
BILLIONS OF CUBIC FEET



Financial Review

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, 1983. These comments should be read in conjunction with the consolidated financial statements, unaudited supplementary information, the five year review of operations and other data contained herein.

EARNINGS

Net earnings for 1983 were $22.5 million, 57 percent higher than the $14.3 million earned in 1982 and more than double the $8.6 million earned in 1981. Net earnings per common share amounted to $1.68 in 1983 compared to $1.07 in 1982, and $0.64 in 1981. Increased earnings are attributed to higher oil and gas income, suspension of mining operations, and increased investment income.

REVENUE

The following table summarizes the composition of operating revenue:

	1983	1982	1981
	(thousands of dollars)		
Crude oil	**$57,056**	$40,727	$30,106
Natural gas	**17,943**	12,503	10,449
Natural gas liquids	**2,599**	1,406	1,202
Sulphur	**1,381**	1,149	2,258
Mining	**—**	310	7,731
	$78,979	$56,095	$51,746

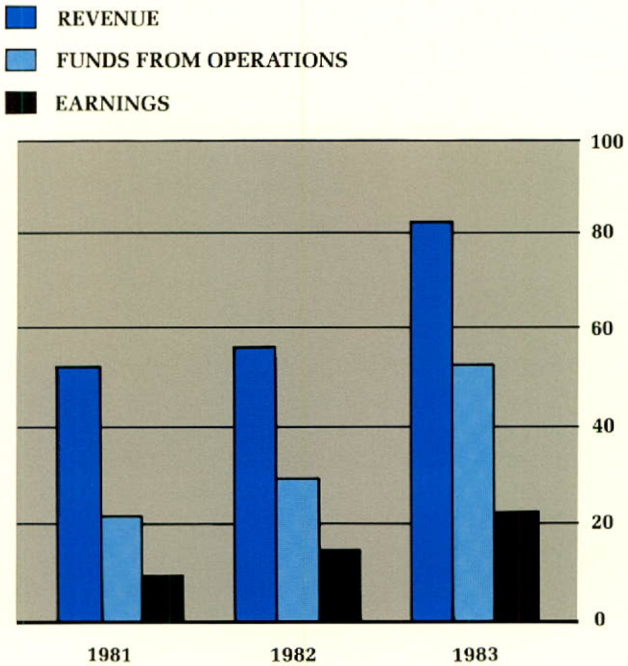
Increased operating revenue reflects reduced Crown royalties, higher oil and gas prices, and increased production, offset, in part, by the suspension of mining operations.

Average oil royalty rates, as a percentage of gross revenue, were 26.1 percent in 1983, down from the 29.4 percent recorded in 1981. Average royalty rates for natural gas decreased from 26.3 percent in 1981 to 14.9 percent in 1983. These royalty reductions result from the overall reduction in royalty rates initiated by the Alberta and Saskatchewan governments and with royalty free status for certain new gas production.

Crude oil production increased 2.2 percent during the three year period ended September 1983 to 7,227 barrels per day, mainly as a result of increased production from the Fort St. John

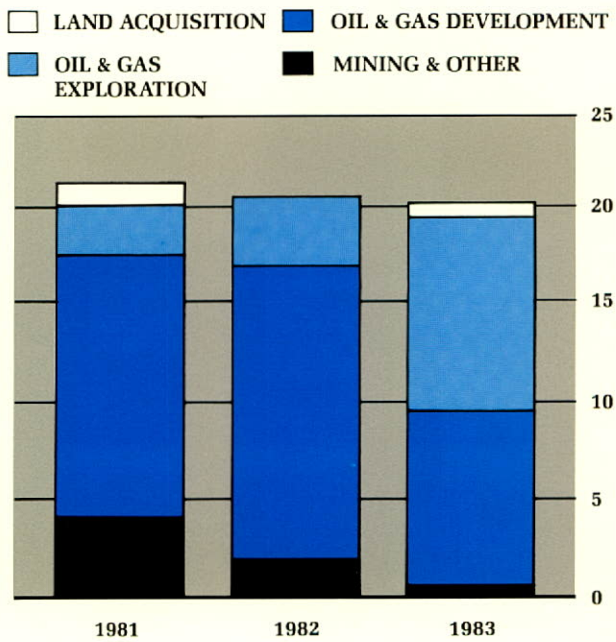
REVENUE — FUNDS FROM — EARNINGS OPERATIONS

MILLIONS OF DOLLARS



CAPITAL EXPENDITURES

MILLIONS OF DOLLARS



area in British Columbia. Gas production increased 24 percent to 20.6 million cubic feet per day over the same period as a result of new gas sales from the South Wapiti and Karr areas of Alberta.

As a result of amendments to federal/provincial pricing agreements, signed in 1983, crude oil is currently categorized into two streams for pricing purposes. Oil discovered after 1974 attracts essentially world price, while oil discovered prior thereto attracts $29.75 per barrel. These arrangements, coupled with previously scheduled price increases, served to increase the average price received for all categories of crude oil to $29.16 per barrel in 1983 compared to $23.19 in 1982 and $16.18 in 1981. The Company's oil production comprises approximately 48 percent discovered prior to 1974 and 52 percent subsequent thereto.

The Alberta border price for natural gas increased $0.25 per thousand cubic feet ("Mcf") February 1, 1983 and a further $0.25 per Mcf to $2.825 per Mcf on August 1, 1983. The price of natural gas is tied to 65 percent of the Toronto refinery gate price of crude oil. To maintain this relationship only a portion of the scheduled $0.25 per Mcf price increase scheduled for February and August 1984 is anticipated. To arrive at field prices for natural gas the Alberta border price is incremented by the United States export price and reduced by transportation charges to the Alberta border. As a result, field prices for natural gas averaged $2.80 per Mcf in 1983 up from $2.46 in 1982 and $2.34 in 1981.

EXPENSES AND TAXES

Operating expenses totalled $12.1 million in 1983, down from $12.7 million in 1982 and $20.7 million recorded in 1981, mainly as a result of the suspension of mining operations in May 1981 and sale of the Gooseberry mine in January 1983. Oil and gas depletion rates per equivalent barrel amounted to $3.59 in 1983, $2.69 in 1982 and $1.94 per barrel in 1981 reflecting higher finding and development costs. Depletion expenses for 1982 and 1981 have been restated to conform to the accounting policy as outlined in note 2 to the consolidated financial statements.

Income tax expense as a percentage of pretax income increased from 36.4 percent in 1981 to 38.1 percent in 1983, reflecting the phasing out of earned depletion allowances offset, in part, by non-deductible mining losses and increased Alberta Royalty Tax Credit.

As part of the National Energy Program, the Petroleum and Gas Revenue Tax was implemented in 1981. This tax totalled $9.6 million in 1983, up from the $2.8 million in 1981, as a result of higher rates and increased oil and gas revenue.

CAPITAL EXPENDITURES AND CORPORATE LIQUIDITY

Capital expenditures (net of PIP grants) amounted to $20.2 million in 1983 compared with $20.7 million in 1982 and $21.7 million in 1981. The 1983 capital program included $10.5 million on exploration of which approximately $5 million was spent on exploration programs in the Beaufort Sea. Development programs continued during 1983 primarily in the Fort St. John area of British Columbia and the Gold Creek area of Alberta with expenditures of $9.4 million.

As part of the National Energy Program, the Company's PIP grants totalled $23 million in 1983 compared with $4.2 million in 1982 and $3.3 million in 1981. The increase in 1983 relates mainly to the Beaufort Sea exploration program, where eligible exploration expenditures are 80 percent recoverable through PIP grants.

Capital expenditures for 1984 are anticipated to approximate $47 million (net of PIP grants).

Total sources of funds in 1983 amounted to $62.6 million compared to $30.5 million in 1982 and $22.5 million in 1981. Funds generated from operations increased to $52.6 million in 1983 and were supplemented by $10.1 million from other sources, primarily the sale of the Gooseberry mine and the disposition of the Company's United States oil and gas assets. Total sources of funds were sufficient to finance the capital program and debt obligations, consequently, at year-end, the Company had working capital of $35.7 million. This compares to year-end working capital deficiencies of $1 million in 1982 and $4.6 million in 1981.

The number of common shares outstanding at September 30, 1983, after reflecting the five for one split, remained unchanged from the prior year at 13,391,780. At year-end, long term debt represented 6.1 percent of total debt and equity capital. The Company had approximately $16 million of unused bank lines of credit, which together with funds from operations will be available to finance anticipated capital programs.

Consolidated Balance Sheet

	September 30, 1983	September 30, 1982
	(Expressed in thousands)	(note 2)
Assets		
CURRENT ASSETS		
Cash and short term deposits	$ 220	$ 6,156
Advances to parent company (note 9)	25,300	—
Accounts receivable		
Trade	13,621	14,809
Petroleum incentives program	23,832	7,546
Inventories, at lower of cost and net realizable value	650	1,669
	63,623	30,180
INVESTMENT IN 50% OWNED COMPANY	1,054	1,060
PROPERTY, PLANT AND EQUIPMENT (note 3)	141,587	145,318
OTHER ASSETS (note 3)	5,271	854
	$211,535	$177,412
Liabilities		
CURRENT LIABILITIES		
Bank indebtedness (note 4)	$ 2,711	$ 5,120
Accounts payable	14,538	15,827
Taxes payable	9,750	8,451
Due to parent company	905	1,708
Current portion of long term debt	31	31
	27,935	31,137
DEFERRED PRODUCTION REVENUE	2,860	1,919
LONG TERM DEBT (note 5)	7,689	9,386
DEFERRED INCOME TAXES	52,080	36,800
MINORITY INTEREST	1,922	1,584
Shareholders' Equity		
CAPITAL STOCK (note 6)		
Authorized		
100,000,000 preferred shares, without par value		
200,000,000 common shares, without par value		
Issued		
13,391,780 common shares	9,374	9,374
CONTRIBUTED SURPLUS	23,334	23,334
RETAINED EARNINGS	86,341	63,878
	119,049	96,586
	$211,535	$177,412

Approved by the Board

K. T. Hashayne Director

Robert G. Black Director

Consolidated Statement of Earnings

	Year ended September 30,		
	1983	1982	1981
	(Expressed in thousands except per share amounts)		(note 2)
REVENUE			
Operating	$78,979	$56,095	$51,746
Other income (note 9)	3,110	479	891
	82,089	56,574	52,637
EXPENSE			
Operating	12,134	12,673	20,714
General and administrative	2,303	1,471	1,465
Depletion and depreciation	15,029	9,713	9,111
Interest on long term debt	416	1,044	2,635
Other interest	29	1,029	755
Minority interest	338	26	23
	30,249	25,956	34,703
EARNINGS BEFORE TAXES	51,840	30,618	17,934
TAXES (note 7)	29,377	16,294	9,352
NET EARNINGS	$22,463	$14,324	$ 8,582
EARNINGS PER SHARE (note 6)	$ 1.68	$ 1.07	$ 0.64

Consolidated Statement of Retained Earnings

	Year ended September 30,		
	1983	1982	1981
	(Expressed in thousands)		
BEGINNING OF YEAR			
As previously reported	$68,316	$53,153	$43,739
Change in accounting policy (note 2)	(4,438)	(3,599)	(2,767)
As restated	63,878	49,554	40,972
NET EARNINGS	22,463	14,324	8,582
END OF YEAR	$86,341	$63,878	$49,554

Consolidated Statement of Changes in Financial Position

	Year ended September 30,		
	1983	1982	1981
	(Expressed in thousands) (note 2)		
FUNDS WERE OBTAINED FROM			
Operations			
Net earnings	**$22,463**	$14,324	$ 8,582
Items not affecting funds			
Depletion and depreciation	**15,029**	9,713	9,111
Deferred income taxes	**15,280**	5,948	4,094
Other	**(218)**	(376)	(235)
	52,554	29,609	21,552
Disposal of assets	**9,123**	366	451
Deferred production revenue	**941**	287	521
Other	**—**	263	—
	62,618	30,525	22,524
FUNDS WERE USED FOR			
Property, plant and equipment	**20,203**	20,717	21,667
Reduction in long term debt	**1,487**	6,147	9,104
Other	**4,283**	—	95
	25,973	26,864	30,866
INCREASE (DECREASE) IN WORKING CAPITAL	**36,645**	3,661	(8,342)
WORKING CAPITAL (DEFICIENCY) AT BEGINNING OF YEAR	**(957)**	(4,618)	3,724
WORKING CAPITAL (DEFICIENCY) AT END OF YEAR	**$35,688**	$ (957)	$ (4,618)
CHANGES IN COMPONENTS OF WORKING CAPITAL			
INCREASE (DECREASE) IN CURRENT ASSETS			
Cash and short term deposits	**$ (5,936)**	$ 6,091	$ (131)
Advances to parent company	**25,300**	—	—
Notes receivable from an affiliated company	**—**	(2,534)	(4,020)
Accounts receivable			
Trade	**(1,188)**	6,446	(3,529)
Petroleum incentives program	**16,286**	4,240	3,306
Income taxes recoverable	**—**	—	(1,527)
Inventories	**(1,019)**	(375)	(449)
	33,443	13,868	(6,350)
INCREASE (DECREASE) IN CURRENT LIABILITIES			
Bank indebtedness	**(2,409)**	240	1,162
Accounts payable	**(1,289)**	4,730	(3,008)
Taxes payable	**1,299**	4,611	3,840
Due to parent company	**(803)**	625	(3)
Current portion of long term debt	**—**	1	1
	(3,202)	10,207	1,992
INCREASE (DECREASE) IN WORKING CAPITAL	**$36,645**	$ 3,661	$ (8,342)

Notes to 1983 Consolidated Financial Statements

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Company's 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% of the voting capital stock.

The Company follows the equity method of accounting for its investment in a 50% 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 of the investment in 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.

Depreciation of 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 Operations

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.

Costs, including equipment costs, are accumulated by producing area and are depleted or depreciated using the unit of production method based upon estimated recoverable ore reserves, as determined by Company engineers.

2. CHANGE IN ACCOUNTING POLICY

Prior to October 1, 1982, the Company followed the full cost method of accounting for oil and gas operations whereby all exploration and development costs were capitalized and accumulated in the North America (Canada and the United States) cost centre.

Costs accumulated in the North America cost centre were depleted using the unit of production method based upon estimated proved reserves, as determined by Company engineers. Oil and gas production equipment was depreciated on a straight-line basis.

Effective October 1, 1982 the Company retroactively changed its accounting policy in respect of its oil and gas operations to the policy described in note 1. These changes were made to conform with the methods prescribed by the United States Securities and Exchange Commission. The comparative financial statements for the years ended September 30, 1982 and 1981 have been restated to give effect to this change. As a result of this change, net earnings decreased by $911,000 ($0.07 per share), $839,000 ($0.06 per share), and $832,000 ($0.06 per share), for 1983, 1982 and 1981 respectively. The cumulative effect of the change to September 30, 1982 results in a reduction in retained earnings of $4,438,000 ($0.33 per share). Under United States accounting principles, the cumulative effect of the change to September 30, 1982 would be charged to earnings for the year ended September 30, 1983.

3. PROPERTY, PLANT AND EQUIPMENT

	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**

	1982 (note 2)		
	Cost	**Accumulated depletion and depreciation**	**Net**
Petroleum and natural gas properties and equipment	$214,610	$83,106	$131,504
Mining properties and equipment			
Developed	14,046	2,815	11,231
Undeveloped	4,593	2,978	1,615
Land, buildings and other equipment	1,549	581	968
	$234,798	$89,480	$145,318

Costs of petroleum and natural gas properties at September 30, 1983 have been reduced by credits of $30,513,000 with respect to petroleum incentives program grants.

The developed mining properties pertain to the Company's interest in 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 has been discounted at a rate of 10% to $4,535,000 (included in other assets). The Company has retained a net profits interest ranging from 15% to 30% depending on the price of gold.

4. BANK INDEBTEDNESS

Bank indebtedness is partially secured by general assignment of certain accounts receivable and interests in certain petroleum and natural gas properties. At September 30, 1983, the Company had unused lines of credit totalling $11,000,000.

5. LONG TERM DEBT

	September 30, 1983	September 30, 1982
7.25% subordinated debentures	$7,505	$9,218
Other	215	199
	7,720	9,417
Less: Current portion	31	31
	$7,689	$9,386

The Company has an unused bank revolving term loan facility amounting to $5,000,000 at September 30, 1983. The loan can be drawn on a revolving basis up to April 30, 1985 at which time the balance is convertible into a term loan, repayable over a period of six years. The loan would bear interest at a Canadian bank's prime rate and would be secured by a general assignment of certain accounts receivable and interests in certain petroleum and natural gas properties.

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 its sinking fund obligations. Debentures purchased to September 30, 1983 satisfy installment requirements to November 1, 1983 and a balance of $759,000 remains to be applied against subsequent sinking fund requirements.

The estimated amount of long term debt maturities and sinking fund requirements for the five years subsequent to September 30, 1983 are as follows: 1984 — $31,000, 1985 — $339,000, 1986 — $1,098,000, 1987 — $1,098,000, 1988 — $5,093,000.

6. CAPITAL STOCK

During the year, the authorized capital stock of the Company was increased to 200,000,000 common shares without par value. The previously authorized 7,500,000 common shares with a par value of $3.50 each were split five for one, and in addition, a further 162,500,000 common shares without par value were created. The Company also created 100,000,000 preferred shares without par value.

As a result, the number of issued and outstanding common shares increased from 2,678,356 common shares to 13,391,780 common shares. Earnings per share for 1982 and 1981 have been restated to reflect the split in issued and outstanding shares.

7. TAXES

Earnings before taxes, and taxes by geographic area are as follows:

	Year ended September 30,		
	1983	1982 (note 2)	1981
Earnings before taxes			
Canada	**$52,592**	$32,890	$21,907
United States	**(752)**	(2,272)	(3,973)
	$51,840	$30,618	$17,934
Taxes			
Current income taxes — Canada	**$ 8,660**	$ 6,318	$ 3,473
Deferred income taxes			
Canada	**15,280**	5,948	4,456
United States	**—**	—	(362)
	15,280	5,948	4,094
Petroleum and gas revenue tax — Canada	**9,616**	5,871	2,820
Incremental oil revenue tax — Canada	**—**	1,246	—
Alberta royalty tax credit — Canada	**(4,179)**	(3,089)	(1,035)
	$29,377	$16,294	$ 9,352

Deferred income tax expense arises from the following timing differences:

	Year ended September 30,		
	1983	1982 (note 2)	1981
Exploration and development costs deducted for income tax purposes in excess of related provision for depletion	**$15,564**	$ 5,216	$ 2,132
Capital cost allowance claimed for income tax purposes in excess of related provision for depreciation	**(284)**	732	2,324
Reduction in deferred income taxes resulting from losses	**—**	—	(362)
	$15,280	$ 5,948	$ 4,094

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

	Year ended September 30,		
	1983	1982 (note 2)	1981
Earnings before taxes	**$51,840**	$30,618	$17,934
Canadian expected income tax rate	**46%**	46%	46%
Computed "expected" income tax expense	**$23,846**	$14,085	$ 8,250
Royalties and other payments to provincial governments	**9,535**	6,623	6,568
Petroleum and gas revenue tax	**9,616**	5,871	2,820
Federal resource allowance	**(9,280)**	(6,130)	(5,281)
Depletion allowances on Canadian oil and gas production income	**(1,333)**	(2,378)	(3,069)
Alberta royalty tax credit	**(4,179)**	(3,089)	(1,035)
Refund of taxes under incentive plans	**(457)**	(423)	(700)
Losses not currently recognized for income tax purposes	**346**	909	1,348
Provincial income taxes net of federal income tax abatement	**1,267**	691	345
Other	**16**	135	106
Actual tax expense	**$29,377**	$16,294	$ 9,352
Actual tax rate as a percentage of earnings before taxes	**56.7%**	53.2%	52.1%

8. BUSINESS AND GEOGRAPHIC SEGMENTS

The Company's operations consist of two business segments, oil and gas and mining, conducted in Canada and the United States. Presented below is financial information by business segment and geographic area:

(a) Business segments

	Year ended September 30,		
	1983	1982 (note 2)	1981
Operating revenues			
Oil and gas	**$ 78,979**	$ 55,785	$ 44,015
Mining	**—**	310	7,731
	$ 78,979	$ 56,095	$ 51,746
Operating income (loss)			
Oil and gas	**$ 42,923**	$ 28,032	$ 23,796
Mining	**(723)**	(1,440)	(4,695)
	42,200	26,592	19,101
Other income	**3,110**	479	891
General and administrative	**(2,303)**	(1,471)	(1,465)
Interest expense	**(445)**	(2,073)	(3,390)
Minority interest	**(338)**	(26)	(23)
Income taxes (net of Alberta royalty tax credit)	**(19,761)**	(9,177)	(6,532)
Net earnings	**$ 22,463**	$ 14,324	$ 8,582
Identifiable assets			
Oil and gas	**$174,009**	$155,414	$138,562
Mining	**6,040**	14,782	13,411
	180,049	170,196	151,973
Corporate assets	**30,432**	6,156	65
Investment in 50% owned company	**1,054**	1,060	1,074
Total assets	**$211,535**	$177,412	$153,112
Capital expenditures			
Oil and gas	**$ 19,990**	$ 19,025	$ 17,743
Mining	**213**	1,692	3,924
	$ 20,203	$ 20,717	$ 21,667
Depletion and depreciation			
Oil and gas	**$ 14,627**	$ 9,472	$ 8,135
Mining	**402**	241	976
	$ 15,029	$ 9,713	$ 9,111

(b) Geographic areas

	Year ended September 30,		
	1983	1982 (note 2)	1981
Operating revenues (i)			
Canada	**$ 78,942**	$ 55,743	$ 44,466
United States	**37**	352	7,280
	$ 78,979	$ 56,095	$ 51,746
Operating income (loss) (ii)			
Canada	**$ 43,207**	$ 29,012	$ 23,702
United States	**(1,007)**	(2,420)	(4,601)
	$ 42,200	$ 26,592	$ 19,101
Identifiable assets			
Canada	**$175,819**	$153,310	$134,174
United States	**4,230**	16,886	17,799
	$180,049	$170,196	$151,973
Capital expenditures			
Canada	**$ 20,190**	$ 20,050	$ 18,275
United States	**13**	667	3,392
	$ 20,203	$ 20,717	$ 21,667
(i) Net of royalties of	**$ 24,064**	$ 17,273	$ 17,009
(ii) Net of maintenance and repairs of	**$ 1,586**	$ 1,691	$ 1,454
Taxes, other than income taxes, petroleum and gas revenue tax and incremental oil revenue tax	**$ 2,534**	$ 1,711	$ 1,480

Capital expenditures are net of petroleum incentives program grants of $22,967,000, $4,240,000 and $3,306,000 for 1983, 1982 and 1981, respectively.

9. RELATED PARTY TRANSACTIONS

Home Oil Company Limited ("Home") owns approximately 88.5% of the issued and outstanding shares of the Company. During the three years ended September 30, 1983, Home furnished certain management, accounting, administrative, technical and other services to the Company and its subsidiaries at charges equal to the cost of services rendered, which amounted to $6,111,000 (1982 — $5,245,000; 1981 — $3,812,000).

Advances to parent company carry interest at ¼% above the cost of funds in the commercial paper market and are payable on demand. The Company earned interest on these advances of $1,573,000 during 1983.

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

10. REMUNERATION PAID TO DIRECTORS AND SENIOR OFFICERS

Remuneration paid to directors during the year ended September 30, 1983 was $40,000. No remuneration was paid to senior officers in their capacity as senior officers; such costs are included in the management fees charged by Home.

11. CAPITAL COMMITMENTS

Under the terms of agreements with Home, Dome Petroleum Limited and Dome Canada Limited, the Company agreed to invest a minimum of $163 million over a three year period which commenced July 7, 1983. In the western Canadian provinces, the Company has committed to spend $55 million on exploration and development wells. Approximately $108 million is committed to be spent on exploration 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% of exploration costs and 20% of development costs. Eligible exploration costs in the Beaufort Sea entitle the Company to grants of 80%. The Company's commitment to the Beaufort Sea program is contingent on the continuance of the petroleum incentives program. To September 30, 1983, the Company had incurred expenditures of $5,439,000, net of petroleum incentives program grants of $21,050,000.

Unaudited Supplementary Information

(a) Selected quarterly financial data

	Quarter ended (notes 2 and 6)			
	December 31, 1982	March 31, 1983	June 30, 1983	September 30, 1983
Revenue	$19,132	$23,626	$18,658	$20,673
Gross margin	$15,961	$19,782	$15,412	$16,497
Net earnings	$ 4,678	$ 6,745	$ 5,122	$ 5,918
Earnings per share	$ 0.35	$ 0.51	$ 0.38	$ 0.44

	December 31, 1981	March 31, 1982	June 30, 1982	September 30, 1982
Revenue	$11,731	$13,928	$15,463	$15,452
Gross margin	$ 9,179	$10,320	$11,835	$11,096
Net earnings	$ 3,365	$ 3,382	$ 3,772	$ 3,805
Earnings per share	$ 0.25	$ 0.25	$ 0.28	$ 0.29

(b) Oil and gas exploration and production activities

The Company's oil and gas exploration and producing 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 (SFAS) No. 69, "Disclosures about Oil and Gas Producing Activities".

	Year ended September 30,		
	1983	1982 (note 2)	1981
Capitalized Costs			
Petroleum and natural gas properties	$226,311	$214,610	$196,069
Accumulated depletion and depreciation	(90,928)	(83,106)	(73,763)
Net book value	$135,383	$131,504	$122,306
Costs Incurred			
Acquisition of unproved properties	$ 773	$ —	$ 1,407
Exploration	9,760	3,594	2,476
Development	9,355	15,325	13,771
Other	102	106	89
	$ 19,990	$ 19,025	$ 17,743

Results of Operations for Oil and Gas Producing Activities

	Year ended September 30, 1983	1982 (note 2)	1981
Revenues, net of royalties	$ 78,979	$ 55,785	$ 44,015
Production (lifting) costs	11,813	11,164	9,264
Petroleum and gas revenue tax	9,616	5,871	2,820
Incremental oil revenue tax	—	1,246	—
Depletion and depreciation	14,627	9,472	8,135
	36,056	27,753	20,219
Income before income tax from oil and gas operations	42,923	28,032	23,796
Income tax expense (net of Alberta royalty tax credit)	20,031	11,426	10,325
Results of operations for oil and gas operations (excluding general and administrative overhead and interest costs)	$ 22,892	$ 16,606	$ 13,471

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 in respect of each reservoir. 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.

	Year ended September 30, 1983		1982		1981	
	Crude Oil (thousands of barrels)	Natural Gas (billions of cubic feet)	Crude Oil (thousands of barrels)	Natural Gas (billions of cubic feet)	Crude Oil (thousands of barrels)	Natural Gas (billions of cubic feet)
Proved reserves						
Beginning of year	14,183	134	15,586	105	13,255	121
Revisions of previous estimates and improved recovery	478	15	(363)	18	3,840	(17)
Discoveries and extensions	1,127	3	791	16	371	5
Production	(2,055)	(6)	(1,831)	(5)	(1,880)	(4)
End of year	13,733	146	14,183	134	15,586	105
Proved developed reserves						
Beginning of year	14,183	134	15,586	105	13,255	121
End of year	12,936	132	14,183	134	15,586	105

Discounted Future Net Cash Flows and Changes Therein From Proved Reserves

Estimated future cash flows 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 ("P.G.R.T."), and income taxes (net of Alberta royalty tax credit), are deducted from estimated future cash flows to arrive at estimated future net cash flows. Future development and production costs have been computed by estimating the expenditures to be incurred in developing and producing the proved reserves at year-end, based on year-end costs and assuming continuation of existing economic and operating conditions. Estimated future P.G.R.T. levied on oil and gas production from proved reserves, is computed based on rates and legislation in effect at year-end. Future income tax expense has been computed by applying the appropriate year-end statutory rates, to the future taxable income to be generated from proved reserves after making provision for the tax basis of the oil and gas properties. Future net cash flows are discounted at a rate of 10% 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 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 impact 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% may not appropriately reflect future interest rates.

Discounted Future Net Cash Flows From Proved Oil and Gas Reserves

	Year ended September 30,		
	1983	1982	1981
Estimated future cash inflows	**$854,872**	$817,895	$704,094
Estimated future production costs	**(171,300)**	(133,089)	(166,602)
Estimated future development costs	**(28,731)**	(39,000)	(29,684)
Estimated future P.G.R.T.	**(104,601)**	(126,000)	(92,244)
Estimated future pretax cash flows	**550,240**	519,806	415,564
Estimated future income tax expenses	**(243,535)**	(237,241)	(171,990)
Estimated future net cash flows	**306,705**	282,565	243,574
Discount at 10% per annum for estimated future net cash flows	**(153,986)**	(151,658)	(141,444)
Discounted future net cash flows	**$152,719**	$130,907	$102,130

Changes in Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	1983	1982	1981
Discounted future net cash flows, before income taxes, at beginning of year	**$232,657**	$167,052	$187,839
Revisions to reserves proved in prior years			
Revisions in quantity and timing estimates	**17,388**	(30,304)	(14,506)
Net change in prices, net of lifting costs and P.G.R.T., related to production	**29,738**	106,713	16,257
Change in estimated future development costs	**8,085**	(9,798)	9,270
Introduction of P.G.R.T.	**—**	—	(35,239)
Other changes	**857**	1,118	3,328
Accretion of discount	**23,266**	16,705	18,784
	311,991	251,486	185,733
Discoveries and extensions, net of related costs	**19,317**	14,428	2,853
Previously estimated development costs incurred during the year	**6,762**	4,247	10,397
Revenue, net of lifting costs and P.G.R.T., from production	**(57,550)**	(37,504)	(31,931)
Discounted future net cash flows, before income taxes, at end of year	**280,520**	232,657	167,052
Discounted future income taxes			
At beginning of year	**(101,750)**	(64,922)	(66,195)
Net change during the year	**(26,051)**	(36,828)	1,273
At end of year	**(127,801)**	(101,750)	(64,922)
Discounted future net cash flows at end of year	**$152,719**	$130,907	$102,130

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, 1983 and 1982 and the consolidated statements of earnings, retained earnings and changes in financial position for each of the two years in the period ended September 30, 1983. 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, 1983 and 1982 and the results of its operations and the changes in its financial position for each of the two years in the period ended September 30, 1983 in accordance with generally accepted accounting principles in Canada applied, after giving retroactive effect to the change (with which we concur) in the method of accounting for oil and gas operations as explained in note 2 to the consolidated financial statements, on a basis consistent with that of the preceding year.

We also reviewed the adjustments described in note 2 to the consolidated financial statements that were applied to restate the 1981 consolidated statements of earnings, retained earnings and changes in financial position. In our opinion, such adjustments are appropriate and have been properly applied to those statements.

The consolidated statements of earnings, retained earnings and changes in financial position of Scurry-Rainbow Oil Limited for the year ended September 30, 1981, before the above restatement, were examined by other auditors whose report dated November 17, 1981 expressed an unqualified opinion on those statements.

Price Waterhouse

Calgary, Canada
November 16, 1983

Chartered Accountants

Five-Year Financial and Operating Review

	Year ended September 30, 1983	1982	1981	Nine months ended September 30, 1980	Year ended December 31, 1979
Financial					
(Expressed in thousands except per share amounts)					
Revenue					
Crude oil and natural gas liquids	$ 59,655	$ 42,133	$ 31,308	$ 18,586	$ 22,590
Natural gas and related products	19,324	13,652	12,707	9,808	10,566
Mining	—	310	7,731	15,150	10,866
Other income	3,110	479	891	747	279
	$ 82,089	$ 56,574	$ 52,637	$ 44,291	$ 44,301
Earnings					
Net earnings before gain on sale of North Sea properties and extraordinary item	$ 22,463	$ 14,324	$ 8,582	$ 13,202	$ 12,819
Per share	1.68	1.07	0.64	0.99	0.96
Net earnings before extraordinary item	22,463	14,324	8,582	13,202	16,082
Per share	1.68	1.07	0.64	0.99	1.20
Net earnings	22,463	14,324	8,582	15,787	18,296
Per share	1.68	1.07	0.64	1.18	1.37
Funds generated from operations	$ 52,554	$ 29,609	$ 21,552	$ 26,945	$ 27,286
Per share	3.92	2.21	1.61	2.01	2.04
Total assets	$211,535	$177,412	$153,112	$147,204	$123,181
Long term debt (including current portion)	$ 7,720	$ 9,417	$ 15,908	$ 25,212	$ 21,613
Capital expenditures					
Oil and gas					
Land acquisition	$ 773	$ —	$ 1,407	$ 383	$ 5,334
Exploration	9,760	3,594	2,476	7,292	15,609
Development	9,355	15,325	13,771	15,739	14,449
Mining	213	1,692	3,752	2,159	2,528
Other	102	106	261	93	131
	$ 20,203	$ 20,717	$ 21,667	$ 25,666	$ 38,051
Shares outstanding at end of period	13,391,780	13,391,780	13,391,780	13,391,780	13,391,780
Operating					
Production					
Crude oil and natural gas liquids					
— barrels per day	7,598	6,724	7,323	7,340	7,768
Natural gas					
— thousands of cubic feet per day	20,622	16,824	16,593	17,676	18,812
Drilling activity					
Gross wells drilled	70	54	70	72	162
Working interest	53	42	47	46	135
Royalty interest	17	12	23	26	27
Net wells drilled	11.93	15.07	10.79	11.08	28.10
Oil	8.07	6.77	5.84	6.43	15.39
Gas	0.50	2.34	2.30	2.13	9.63
Proved oil and gas reserves at end of period					
Crude oil and natural gas liquids					
— millions of barrels	17.6	18.9	24.8	20.8	22.6
Natural gas					
— billions of cubic feet	179	169	183	174	180
Landholdings at end of period (thousands)					
Petroleum and natural gas					
Gross acreage	4,342	4,793	5,052	6,136	5,578
Net acreage	1,477	1,521	1,681	1,778	1,645
Mining					
Gross acreage	163	462	672	773	597
Net acreage	77	173	217	249	259

The above data incorporate retroactive adjustments

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
Deputy Chairman 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
General Manager Planning and Corporate Secretary

A.R. Hagerman
Treasurer

E. Jorgensen
Comptroller

Auditors

Price Waterhouse
Calgary, Alberta

Registrar and Transfer Agents

Guaranty Trust Company of Canada
Calgary, Toronto, Montreal, Vancouver
The Canadian Bank of Commerce Trust Company
New York, N.Y.

Stock Exchange Listings	**Symbols**
Toronto Stock Exchange	SCR
American Stock Exchange	SRB

Common Shares

	Prices*			
	Toronto Stock Exchange (Cdn dollars)		American Stock Exchange (U.S. dollars)	
	High	Low	High	Low
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
Close at September 30, 1983	20		16½	
Year ended September 30, 1982				
1st quarter	13	8	11¼	6⅞
2nd quarter	10⅝	6½	8¾	5¾
3rd quarter	7¾	6⅝	6⅝	5⅜
4th quarter	10½	7¼	8¾	5½

* Adjusted to reflect five for one share split which became effective July 5, 1983.

At September 30, 1983, the Company had 13,391,780 common shares issued and outstanding, held by 3,516 shareholders.

No dividends have been paid 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 non-residents 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.

Principal Affiliates

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

Principal Affiliate Offices

Plains Petroleums Limited
2300 Home Oil Tower
324 Eighth Avenue S.W.
Calgary, Alberta, Canada
T2P 2Z5

Minerals Limited
2000 One Palliser Square
P.O. Box 2850
Calgary, Alberta, Canada
T2P 2S5

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)

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