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Dome Petroleum Limited

Annual Report 1984

The Company

Dome Petroleum Limited is a major participant in Canada's oil and gas industry. The Company has three core business segments. It explores for, develops and produces crude oil and natural gas in Canada, extracts and purchases natural gas liquids (NGL) in Canada, transports and markets NGL in Canada and the United States, and undertakes contract drilling and related services in the Beaufort Sea region of Canada and the U.S.

Oil and Gas

Virtually all of Dome's development drilling and its production of oil, natural gas and natural gas liquids are centred in western Canada, where the Company holds the industry's largest spread of oil and gas lands. Exploration programs are conducted in western Canada and Canadian frontier areas.

Natural Gas Liquids

Dome has interests in and operates integrated NGL extraction, gathering and processing facilities in Alberta, fractionation and distribution facilities in eastern Canada and distribution facilities in the U.S. It also has major interests in and operates an ethane gathering system in Alberta and a pipeline carrying ethane and propane to eastern Canada and the U.S.

Contract Drilling

Under the tradename Canmar, Dome undertakes contract drilling in the Canadian and U.S. Beaufort Sea utilizing a fleet of four ice-reinforced drillships, a mobile Arctic drilling vessel (the SSDC), various icebreaker/support vessels and two shorebase facilities.

Contents

(Millions of Canadian Dollars, Except Per Share Amounts)

	1984	1983	1982
Financial			
Revenue			
Crude oil and natural gas	**$ 1,088.3**	$ 946.4	$ 1,003.8
Natural gas liquids	**1,012.5**	1,135.4	1,044.3
Contract drilling	**335.7**	409.3	505.7
Other operating	**11.1**	103.5	296.0
	$ 2,447.6	$ 2,594.6	$ 2,849.8
Operating income before write-downs and gains (losses) on disposal of assets[a]			
Crude oil and natural gas	**$ 532.4**	$ 437.2	$ 516.7
Natural gas liquids	**158.5**	219.8	214.2
Contract drilling	**112.2**	145.6	153.2
Other operating	**(22.8)**	(43.9)	(57.2)
	$ 780.3	$ 758.7	$ 826.9
Net income (loss)	**$ (196.8)**	$ (1,105.0)	$ (369.3)
Per share[b]	***(0.84)***	*(4.72)*	*(1.71)*
Write-downs and gains (losses) on disposal of assets (after deferred income taxes)[a]	**30.0**	(973.5)	(314.0)
Cash from operations[c]	**208.9**	198.4	103.6
Capital expenditures[d]	**129.1**	287.2	595.6
Operating			
Oil and natural gas liquids field production (thousands of barrels/day)	**84**	82	93
Natural gas production (millions of cu.ft./day)	**551**	485	585
Natural gas liquids production from straddle plants (thousands of barrels/day)	**34**	28	31
Natural gas liquids sales (thousands of barrels/day)	**110**	116	123
Reserves of oil, natural gas liquids and oil equivalent of natural gas (millions of barrels)[e]	**1,201**	1,200	1,541
Gross wells drilled (incl. farmouts)	**1,268**	1,009	1,137
Land holdings (thousands of acres) Working interest — gross	**57,957**	66,291	72,343
— net	**24,597**	26,798	27,825

[a] For further detail on write-down and disposal losses, see Management's Discussion and Analysis of the Company's Results of Operations and Financial Condition.

[b] Based on average common shares outstanding, excluding the Company's pro rata interest in its own shares held by Dome Mines.

[c] The Company formerly reported funds generated from operations, a working capital definition versus the cash definition adopted in 1984. For the purpose of continuity and to facilitate comparison with other companies, funds generated from operations for 1984 were $484.1 (1983 — $201.1; 1982 — $224.0).

[d] Exclusive of capitalized interest and general and administrative expenses.

[e] Stated before Crown but after other royalties. 1984 and 1983 values reflect consultants' proved reserves estimates, defined by the SEC, plus 56.6 million (1983 — 61.5 million) barrels of synthetic crude oil. Established reserves for prior years were determined by Company's engineers. Natural gas has been converted to oil equivalent based on heat content.

To Our Shareholders

During 1984, Dome made important strides toward its goal of restoring financial health.

Several achievements are noteworthy:

- the implementation on February 5, 1985, effective as of December 31, 1984, of agreements which rescheduled 83% of the Company's debt repayments over a 12 year period.
- an increase in 1984 operating income from oil and gas operations in western Canada, which offset declines in natural gas liquids and contract drilling operations.
- a 25% reduction in 1984 general and administrative expenses.
- the disposition in 1984 of non-essential assets for a total of $138.8 million.

With regard to the future, a number of steps are being taken to further stabilize and improve Dome's financial position. It is the intention of the Company to issue new equity when possible, dispose of assets which do not earn a reasonable return, improve cash flow from operations, continue to reduce costs, and, if possible at an acceptable cost, fix interest rates on a portion of its floating rate debt. These measures will assist in the orderly reduction of debt and the maintenance of a prudent capital expenditure program. However, changing world oil prices and interest rates will impact on future results.

1984 Results Improve Over 1983

Dome's financial position in 1984 has improved from 1983. Notwithstanding, a net loss of $196.8 million was recorded in 1984 compared with a net loss of $1,105.0 million in 1983, when write-downs aggregating $896.9 million, net of related deferred income taxes of $202.1 million, were made. The net loss per common share was $.84 compared with a net loss of $4.72 per common share in 1983.

The 1984 results included foreign exchange losses of $109.9 million, and other costs of $66.8 million relating to the rescheduling of debt and interest on income taxes of Hudson's Bay Oil and Gas Company Limited (HBOG). The foreign exchange losses and other costs were net of deferred income taxes of $13.1 million and $27.1 million respectively. Other factors affecting 1984 results were lower capitalized interest and higher depletion, depreciation and amortization arising from the policies adopted in 1983, and increased interest rates.

Total operating income before depletion, depreciation and amortization increased by $51.9 million in 1984 to $1,162.4 million, while cash from operations increased to $208.9 million in 1984 from $198.4 million in 1983.

The Company's working capital position improved by $2.7 billion from 1983 as a result of rescheduling debt and other related transactions.

Results in 1985 will be less sensitive to foreign exchange fluctuations due to the transfer of $2.3 billion of debt from current to long term under the Debt Rescheduling Agreement and the conversion of $712 million of U.S. dollar denominated debt to Canadian dollars in September, 1984.

Debt Rescheduling Agreement Closed

The Debt Rescheduling Agreement, between the Company and 56 of its lenders, extends the repayment of $5.3 billion of the Company's long term debt over a 12 year period. Remaining long term debt of $1.1 billion, largely held by the public, is to be repaid on its original schedule. Principal payments due to lenders during the five years ending December 31, 1988 have been reduced by $3.6 billion.

Concurrently with the closing of the Debt Rescheduling Agreement, the Governments of Canada and Alberta granted remission orders with respect to income taxes of HBOG. The remission orders effectively permit the consolidation of HBOG and Dome Energy Limited for income tax purposes. Agreement was also reached with Revenue Canada - Taxation extending payment of outstanding Petroleum and Gas Revenue Tax (PGRT) obligations for the 1982 and 1983 taxation years over a five year period commencing January 2, 1986. These PGRT obligations amounted to $204.1 million including associated interest at December 31, 1984.

Additionally, an agreement was reached extending the repayment of $112.5 million owing to Dome Canada Limited over a five year period commencing January 2, 1986.

The Company has agreed to sell assets for aggregate cash proceeds of at least $150 million prior to December 31, 1986. In a separate undertaking with certain of its lenders, Dome has agreed to sell 10 million of its 31 million shares of Dome Mines Limited, prior to December 31, 1986, which would be included in the $150 million asset sale commitment.

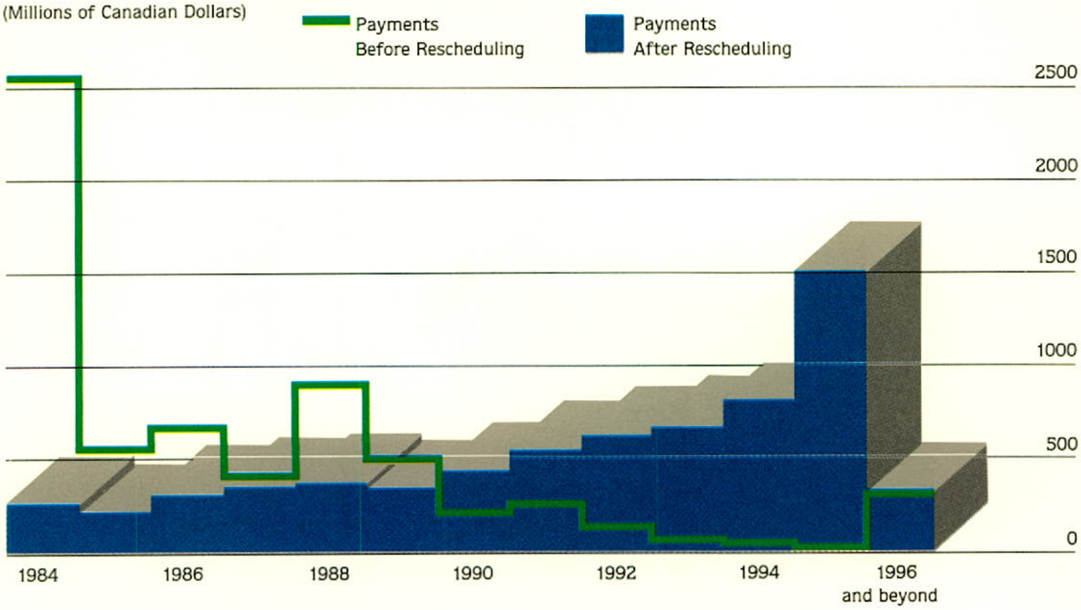
The Company is required to sell common shares, or other securities approved by its lenders, for aggregate cash proceeds of at least $100 million prior to December 31, 1986.

The Debt Rescheduling Agreement also provides access to funds under two additional credit facilities. The Operating Credit Agreement makes available up to $245 million in operating lines secured by accounts receivable. Of this amount, $150 million will be made available during the first year, irrespective of the amount of pledged receivables. Both the Debt Rescheduling Agreement and the Operating Credit Agreement are subject to certain financial tests.

The Secured Project Credit Agreement makes available up to Cdn. $200 million and U.S. $29 million secured by completed capital projects commenced after December 1, 1983.

Debt Principal Payments Before and After Rescheduling

(Millions of Canadian Dollars)



1984 Operating Highlights

Operating income increased in 1984 due to growth in the crude oil and natural gas segment, the largest of the Company's three core businesses, which offset lower operating income from natural gas liquids (NGL) and contract drilling. Canadian oil production was up 6% and Canadian gas production rose 19%. The new West Pembina gas cycling plant commenced production in May, 1984, contributing to increased field production of NGL.

Capital spending in 1984 totalled $129.1 million and was concentrated on the development of western Canada oil and gas operations. The 1985 capital program will be approximately $160 million. Additional expenditures ranging from $400 million to $500 million are expected to be made on Company lands through farmouts to other companies.

In 1984, $87.8 million was spent on development of crude oil and natural gas reserves, with concentration on the drilling of crude oil prospects and contracted natural gas properties. A total of 1,063 gross development wells were drilled, of which 408 were financed through farmouts. Of the total, 69% were oil wells and 21% were natural gas wells. Most of the crude oil wells drilled qualified for approximately world oil price. The Company expects to expand its efforts in developing and producing heavy oil and bitumen, with two commercial projects in the Primrose and Lindbergh regions of Alberta planned for construction in 1985.

During the year, 205 exploratory wells were drilled on Dome lands of which 182 were through farmouts. Of the total, 33% were oil wells and 20% were natural gas wells. Results from 1984 frontier exploration on Dome's lands in the Canadian Beaufort Sea included one delineation well, which flowed non-commercial oil on test and confirmed the productive limits of the west end of the Tarsiut field, and three exploratory wells, one giving non-commercial oil show and two resulting in dry holes.

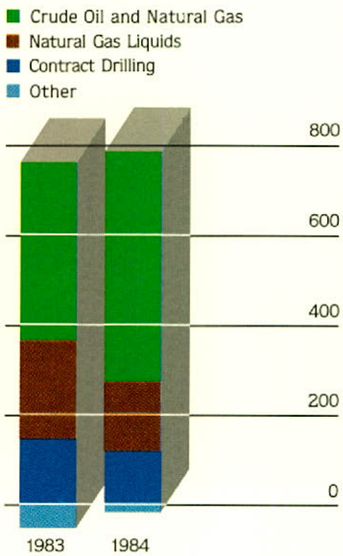
Margins were reduced on NGL sales in 1984 and volumes were adversely affected by lower demand for petrochemicals and warm weather late in the year.

Contract drilling revenues and operating income for 1984 were lower than in 1983, reflecting a reduction in the 1984 drilling program. During 1984, the Company's four drillships were under contract for the full drilling season, and the SSDC mobile drilling vessel was contracted only half of the year. Progress was made in marketing contract drilling services in the U. S. Beaufort Sea and the first contract was awarded for the drilling of one well. Preliminary work was commenced in 1984 and drilling and completion are scheduled in 1985.

John M. Beddome

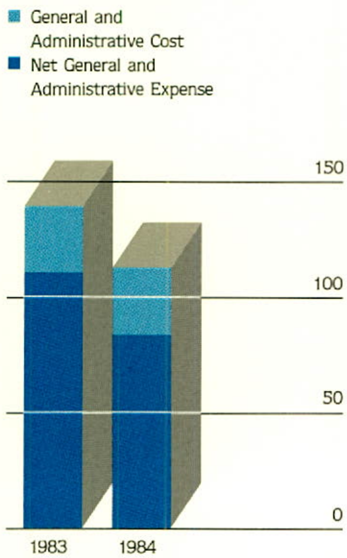
Operating Income by Business Segment

(Millions of Canadian Dollars)



Capitalized General and Administrative Expense

(Millions of Canadian Dollars)



J. Howard Macdonald

Outlook

With the Company's debt rescheduled, the foundation has been laid for financial recovery. Through its three cash generating core businesses, Dome expects to continue to be a major participant in the Canadian energy sector.

One of Dome's important strengths lies in the production of natural gas, where it is a leader. Its gas reserves and production capacity provide it with the ability to meet potential increases in market demand.

Dome ranks as one of Canada's top oil and field NGL producers and expects to increase its production levels in the medium-term through productivity improvements, development drilling and investments in heavy oil.

The Company's extensive land position in western Canada provides it with exceptional exploration opportunities. During the past several years, Dome, in conjunction with its farmout partners, has carried out one of the most active exploration and development programs of any company in Canada, and expects to continue a similar program in 1985.

Dome expects to retain its leadership position in NGL marketing in Canada and continue as one of the largest NGL marketers in North America.

Although overall utilization of the Company's contract drilling systems is expected to be lower in 1985, the contract drilling group, with its extensive Arctic experience, expects to effectively compete for business in new market areas, particularly offshore Alaska.

As market conditions permit, Dome intends to issue new equity in order to fund, in part, the many high value opportunities which exist within its core businesses.

Directors and Officers

No change has been made to the Board of Directors since the Annual Meeting of Shareholders held June 29, 1984. Changes have been made among the Officers of the Company, due to re-organization.

The efforts by Dome employees during these difficult times have been sincerely appreciated. Their support and cooperation have been exceptional.

J. Howard Macdonald
Chairman

John M. Beddome
President

March 25, 1985

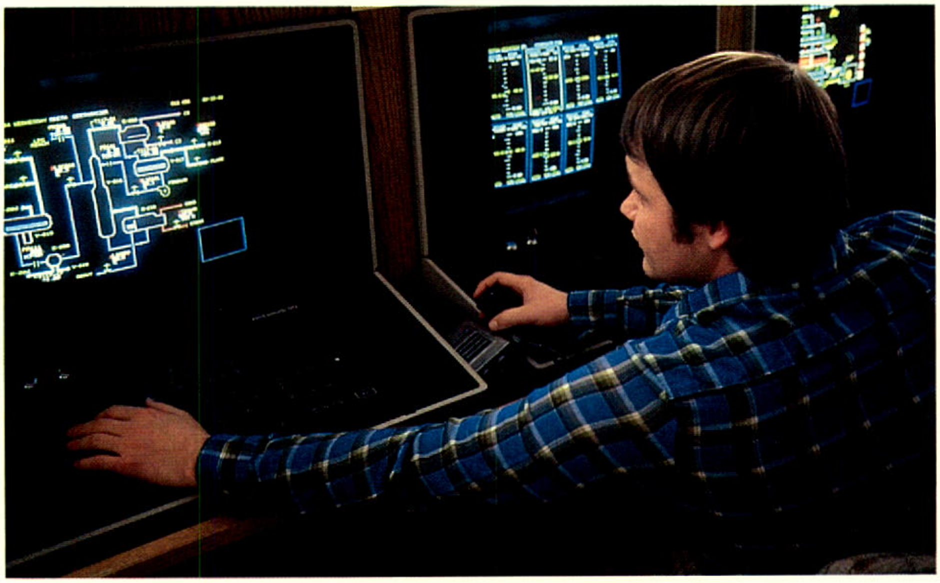
Rig drills one of 38 development wells completed in Caroline-Garrington area in 1984. Dome participated in 1,063 development wells, including farmouts, during the year.

Crude oil and natural gas operating income in 1984 increased 22% as a result of higher average prices and increased gas sales.

Dome's Canadian crude oil production increased by 6% in 1984 as production from new sources, together with productivity improvements, offset declining productivity in older fields and lower synthetic volumes. Higher average oil prices in 1984 resulted from a greater proportion of production qualifying for approximately world price.

The Company's Canadian natural gas production increased 19% in 1984 due to higher export and domestic demand. While export prices for natural gas declined in 1984 and domestic prices remained stable, the higher volumes resulted in reduced pipeline tariffs and increased export flowback.

Modest improvement in oil and field NGL production is expected in 1985. The volume of natural gas exported to the United States is anticipated to increase in 1985, although at prices lower than those received in 1984.



West Pembina plant, which began production in May, 1984, recovers NGL and recycles gas into wells. The new plant played a part in NGL field production increase over that of 1983.

Oil and Gas Operations

Western Canada

Dome produces crude oil and natural gas, and natural gas liquids and sulphur, primarily produced in association with natural gas. Operations are primarily located in the western Canadian provinces of Alberta, British Columbia and Saskatchewan. In 1984, this segment of the Company's business generated $532.4 million (68%) of its operating income.

Land Holdings

Dome holds the largest spread of oil and gas lands in western Canada, with working interests totalling 10.9 million net acres mainly located in traditional producing areas, and on 28% of these lands holds mineral rights in perpetuity. As a result of its wide-spread land holdings, Dome has interests in most of the major producing areas of western Canada and is well positioned to participate in exploration and development activity throughout this region. Substantially all of its developed acreage is on provincial lands.

Capital Expenditures

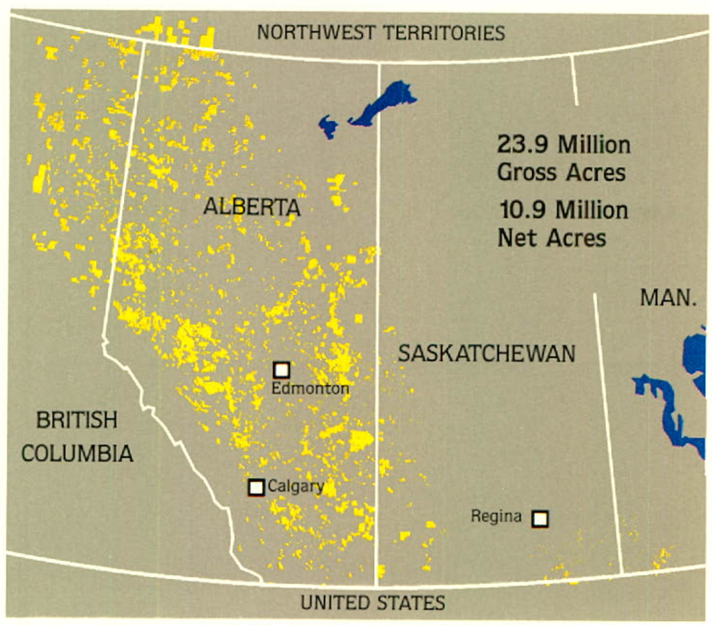
Recent policy has been to fund capital projects which yield the highest rates of return and fastest payouts, and expenditures necessary for the maintenance of Dome's extensive existing facilities.

Exploration has been carried out primarily through farmouts to Dome Canada Limited, Home Oil Company Limited and other companies which, in return for paying all exploration costs, earn varying interests in the properties drilled. This strategy will continue for the time being.

Under the Dome Exploratory Lands Agreement (DELA) with Dome Canada and a similar agreement with

Capital Expenditures ($ Millions)

	1984	1983	1982
Crude oil and natural gas			
— Exploration and land	**$ 10**	$ 1	$ 32
— Development	**88**	193	240
	98	194	272
Natural gas liquids operations	**13**	11	29
Contract drilling operations	**10**	17	43
Other	**8**	65	29
	129	287	373
Capitalized			
— Interest expense	**52**	137	213
— General and administrative expense	**29**	29	54
	210	453	640
Acquisitions	—	—	222
Total	**$210**	$453	$862



Western Canada Land Holdings

Home, Dome Canada and Home pay the Company's share of costs of exploratory drilling on certain lands in western Canada and the Beaufort Sea and all geological and geophysical costs, and in return earn in western Canada working interest of 50% of Dome interests in the lands explored and certain surrounding acreage. In the Beaufort Sea, working interests earned vary from 10% to 50%. Dome Canada and Home have spent $156 million in Western Canada and $664 million in the Beaufort Sea during 1983 and 1984 under the agreement.

In 1985, capital expenditures by the Company are budgeted at approximately $160 million with the bulk of the funds allocated to crude oil and natural gas development in western Canada.

Land Holdings Summary at December 31, 1984
(Thousands of Acres)

	Working Interest[1]		Royalty
	Gross[2]	Net[3]	Interest[4]
Provincial Lands			
Alberta	16,554	6,906	958
British Columbia	3,066	1,013	157
Saskatchewan	3,007	2,021	114
Manitoba	1,251	913	—
Ontario	57	18	—
Total Provincial Lands	23,935	10,871	1,229
Canada Lands			
Arctic Islands	10,214	3,226	7,711
Beaufort Sea	12,207	5,943	—
Northwest Territories	4,843	1,588	1,454
East Coast	6,758	2,969	1,223
Total Canada Lands	34,022	13,726	10,388
TOTAL	**57,957**	**24,597**	**11,617**
Developed[5]	7,220	2,731	834
Undeveloped	50,737	21,866	10,783

(1) "Working Interest" refers to an interest held by the Company in an oil and gas property which entitles the owner to a proportionate share of production and obligates the owner to bear a proportionate share of the costs of exploration, development and operation and any royalties or other production burdens.

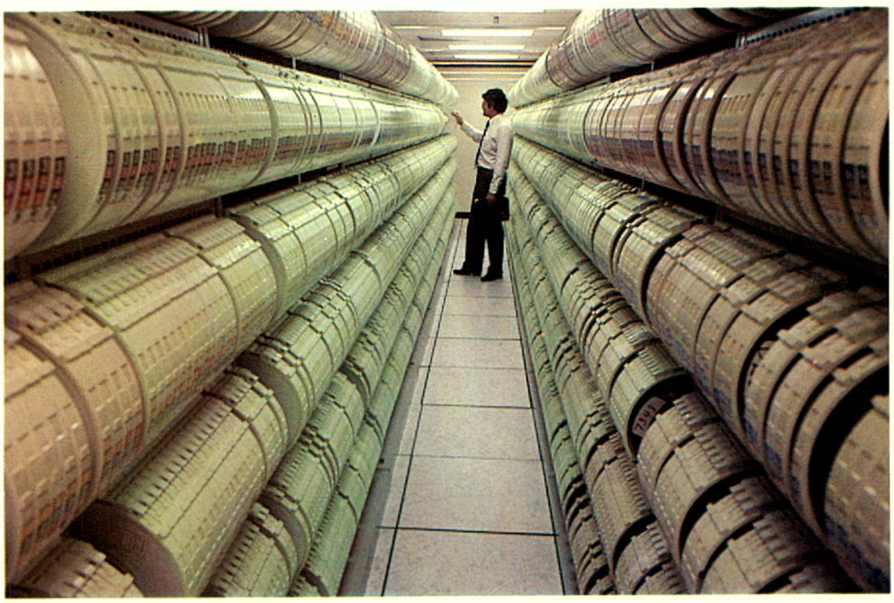
(2) "Gross" refers to the total acreage in which Dome Petroleum has an interest or has the right to earn an interest under farmin agreements.

(3) "Net" refers to the total of the acreage in which Dome Petroleum has a working interest, or has the right to earn a working interest, multiplied by the percentage working interest therein owned or to be owned by Dome Petroleum. Dome Petroleum's interests are subject to royalties and, in some cases, to other non-working interests.

(4) "Royalty Interest" refers to the total acreage in which Dome Petroleum has only a royalty interest rather than a working interest. Dome Petroleum also held royalty interests in 15.9 million acres of its gross working interest lands. These additional royalty interests were held in Alberta (3.0 million gross acres), the Arctic Islands (5.9 million gross acres), the Beaufort Sea (5.6 million gross acres) and the Northwest Territories (1.4 million gross acres).

(5) Substantially all of the Company's developed acreage is on provincial lands.

More than 60,000 reels of computer tape store Dome's seismic data and geological information on its extensive landholdings. Data is used to make decisions on future exploration and development drilling.



Exploration and Development Drilling

Drilling on Dome's western Canada lands was widespread in 1984, with emphasis in Alberta. Drilling activity focused mainly on the discovery of new oil, and on the development of crude oil prospects and contracted natural gas properties in which Dome holds sizable working interests.

Of 205 exploratory wells drilled during 1984, Dome participated directly in the drilling of 23 gross wells resulting in 14 oil and five gas wells. In addition, 96 exploratory wells were drilled on Dome lands under farmouts to Dome Canada and Home and 86 exploratory wells were drilled under other farmouts. The farmout program resulted in 53 oil and 36 gas wells.

The more significant areas of exploration activity in Alberta included Hays-Grand Forks where oil was discovered; Ferrier-Hoadley where a large gas find was made; Carrot Creek where oil was discovered; Gift/Kyle where multi-zone oil discoveries have been made; Simonette where an oil discovery was made; Zama/Shekilie where a number of dual oil and gas discoveries were made; and at Wembley where dual gas zone discoveries were made. In British Columbia, a large gas and oil reserve was discovered in the Weasel-Oteco area and successful exploratory oil wells were also drilled on Company acreage in Saskatchewan and Manitoba.

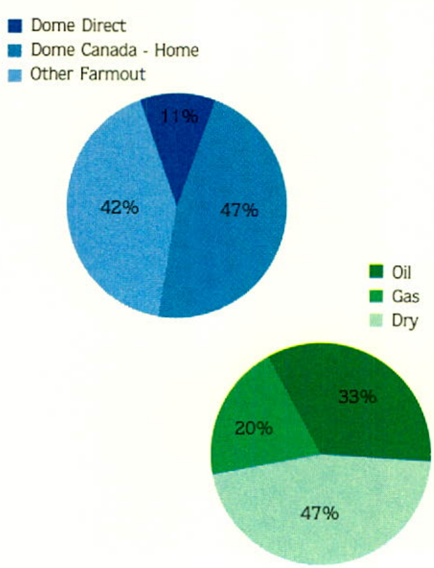
During 1984, a total of 1,063 gross development wells were drilled on Dome lands, of which 729 were oil wells, 221 were natural gas wells and 113 were dry holes. Of the total, 408 development wells were financed under third party farmout arrangements. Most crude oil wells drilled during 1984 qualified for approximately world price.

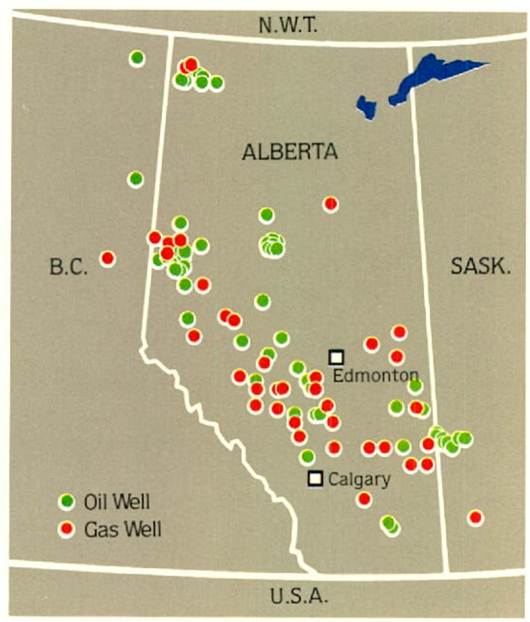
Of the development oil wells completed in 1984, 68% were in Alberta and 31% in Saskatchewan. Of the gas wells completed, 96% were in Alberta.

The major areas of 1984 development activity in Alberta included 38 wells in the Caroline-Garrington area, 65 miles northwest of Calgary. This drilling resulted in 14 oil wells, 18 gas wells and two dual oil/gas wells, increasing oil production by 480 barrels per day. In addition, 10 gas wells were placed on stream, increasing gas production by approximately 10 million cubic feet per day.

At Valhalla, 30 miles northwest of Grande Prairie, 56 wells were drilled into the shallow Doe Creek formation, resulting in 48 oil producing wells, adding 440 barrels per day to oil production. Delineation of this pool is continuing in 1985, and a waterflood project, which is expected to increase recoverable reserves, is planned for implementation later in the year. Eight deeper tests were also drilled, resulting in four oil wells, one gas well and two dual oil/gas wells. Dome's share of initial crude oil production from the deeper Triassic formation averaged 190 barrels per day.

1984 Gross Exploration Wells Drilled





1984 Exploration Drilling Areas

Oil and Gas Reserves

Dome's proved reserves at December 31, 1984, have been evaluated in a report dated March, 1985, prepared jointly by Coles Nikiforuk Pennell Associates Ltd., consulting petroleum engineers, of Calgary, Alberta and Harold Hammar, a consulting petroleum engineer of Scotch Plains, New Jersey.

The Company's reserves are based on the definitions prescribed by the United States Securities and Exchange Commission and therefore exclude Dome's interests in certain proposed enhanced recovery projects, developed and undeveloped synthetic crude oil and crude bitumen, the Canadian Arctic Islands and the Beaufort Sea.

In 1984, proved oil and NGL reserves, before deduction of Crown royalties, increased by 6% or 20.3 million barrels from 1983, as revisions and reserves additions of 49.9 million barrels offset production of 29.3 million barrels and dispositions of 300,000 barrels.

Gas reserves declined by 2% or 86 billion cubic feet from 1983, with revisions and reserves additions of 161 billion cubic feet not entirely replacing production of 196 billion cubic feet and dispositions of 51 billion cubic feet.

Reserves at year-end 1984 had a life index of 11.5 years for oil and NGL and 23 years for natural gas.

Proved Reserves at December 31, 1984

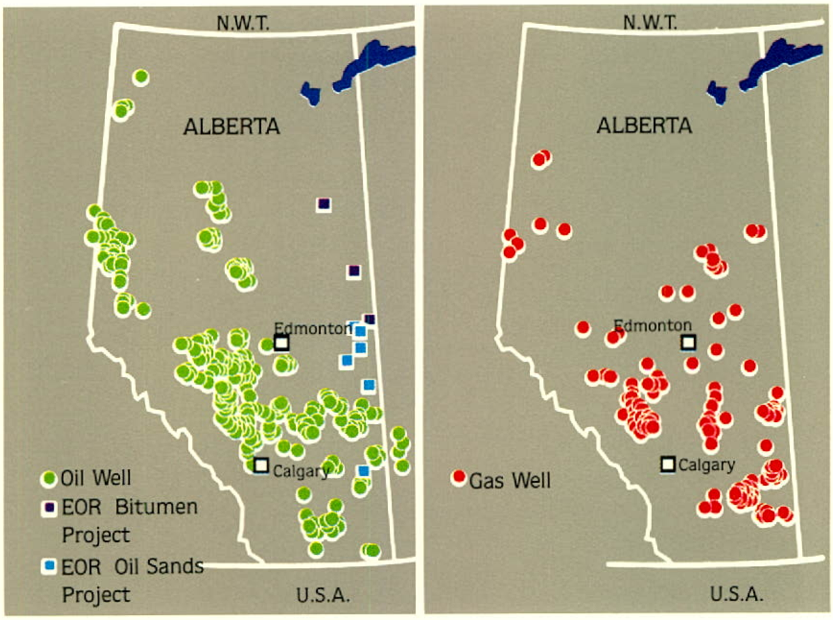
	Proved Developed	Proved Undeveloped	Total Proved
Before deduction of provincial royalties[(1)]			
Crude oil (million of barrels)	207.0	39.8	246.8
NGL (millions of barrels)[(2)]	60.7	30.9	91.6
Natural gas (billions of cubic feet)[(3)]	3,107.4	1,564.8	4,672.2
After deduction of provincial royalties[(4)]			
Crude oil (millions of barrels)	169.3	35.5	204.8
NGL (millions of barrels)[(2)]	44.4	22.6	67.0
Natural gas (billions of cubic feet)[(3)]	2,347.2	1,180.7	3,527.9

(1) Reserves are stated after the deduction of override and freehold royalties.

(2) Includes condensate.

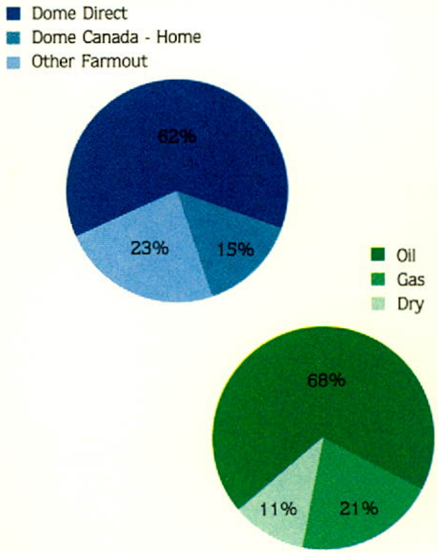
(3) Natural gas volumes have been adjusted to a standard heat content of 1000 British thermal unit per cubic foot.

(4) In order to estimate reserves after giving effect to the deduction of provincial royalties, certain assumptions must be made including forecasts of future prices and production. The reserves net of all royalties are based on Coles Nikiforuk Pennell Associates Ltd. forecasts of these and other factors necessary to estimate provincial royalties.



1984 Development Drilling Areas

1984 Gross Development Wells Drilled



Crude Oil and Field NGL Production

Production of crude oil in 1984 was from the provinces of Alberta (83%) Saskatchewan (13%) and British Columbia (4%) and including synthetic, was on average 70,042 barrels per day, 6% higher than production in 1983. New production plus improvements offset declining productivity in older fields and lower synthetic volumes.

Dome holds an indirect 3.75% interest in the Syncrude Project, which produces synthetic crude oil from oil sands at a plant near Fort McMurray, Alberta. In 1984, the Company's share of plant production of synthetic crude oil averaged 3,230 barrels per day, a 23% decline from 1983 due to a fire at the plant on August 15, 1984, which shut down all operations. The plant resumed production at half rates in September, 1984 and resumed full operation in December, 1984. The Company's reserves of synthetic crude oil are 56.6 million barrels before deduction of Crown royalties.

The Lloydminster heavy oil area, which straddles the Alberta/Saskatchewan border, is the major source of Dome's heavy oil production. In 1984, the Company's share of production from this area averaged 8,189 barrels per day, a 7% increase from 1983.

Production of NGL from field plants averaged 13,612 barrels per day in 1984, virtually unchanged from 1983, as new production from a gas cycling project at West Pembina, Alberta offset the absence in 1984 of production from properties in the United States which were sold in 1983. The West Pembina gas cycling plant, operated by Dome but owned by others, commenced production in May, 1984. The Company owns approximately 55% of the plant feedstock. During the period June through December, 1984, daily production from the plant averaged 7,360 barrels of NGL including condensate and 165 long tons of sulphur.

At Wembley, near Grande Prairie, Alberta, a new gas cycling project is proceeding which is expected to provide Dome an average 2,400 barrels per day of condensate and natural gas liquids in early 1986.

Marketing

All crude oil produced in Canada is currently sold at regulated prices under federal-provincial government pricing agreements. These agreements, which expire on March 31, 1985, unless extended, are currently under review.

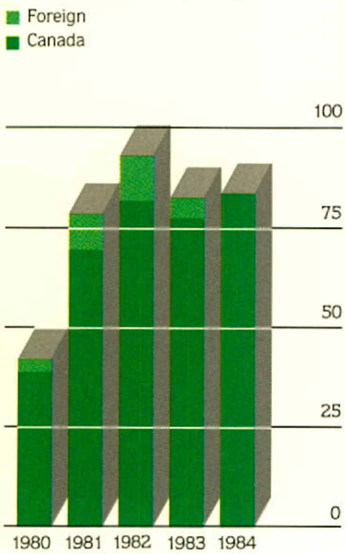
For 1984, 40% of Dome's oil production received the New Oil Reference Price (NORP), which is approximately equal to world price and was $40.18 per barrel for reference quality crude oil as of February 1, 1985. The remaining 60% of crude oil production in 1984 received the Conventional Old Oil Price (COOP), which is currently set at $29.75 per barrel.

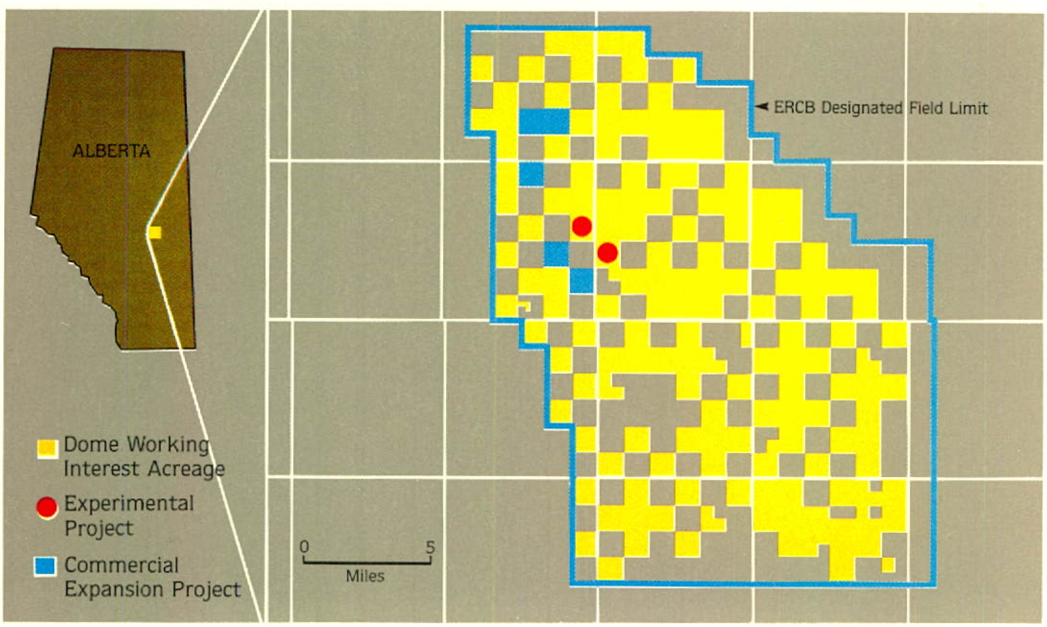
Of total 1984 crude oil production, 70% was marketed as light crude oil (API gravity greater than 29°), while 30% of crude oil production was marketed as medium and heavy oil (API gravity of 29° or less).

In 1983, the Government of Canada began allowing

Oil and Natural Gas Liquids Production

Thousands of Barrels per Day





Lindbergh Heavy Oil Area

exports of light crude oil deemed to be surplus to Canadian needs under short-term export licences. Exports of surplus medium and heavy oil are permitted for periods of up to two years. During 1984, approximately 20% of the Company's medium and heavy oil production was sold to Canadian refineries, with the balance being sold in the U.S.

Enhanced Oil Recovery, Heavy Oil and Bitumen

Dome has initiated several enhanced oil recovery projects which will increase the percentage of total oil in place that is recovered.

In July, 1984, a hydrocarbon miscible flood, light oil enhanced recovery project was implemented in the Kaybob South Triassic Unit No. 1 to increase recoverable reserves in the pool. The project area covers 7,680 acres and includes approximately half of the Unit's total oil in place. Incremental oil recovery is anticipated in the last quarter of 1985.

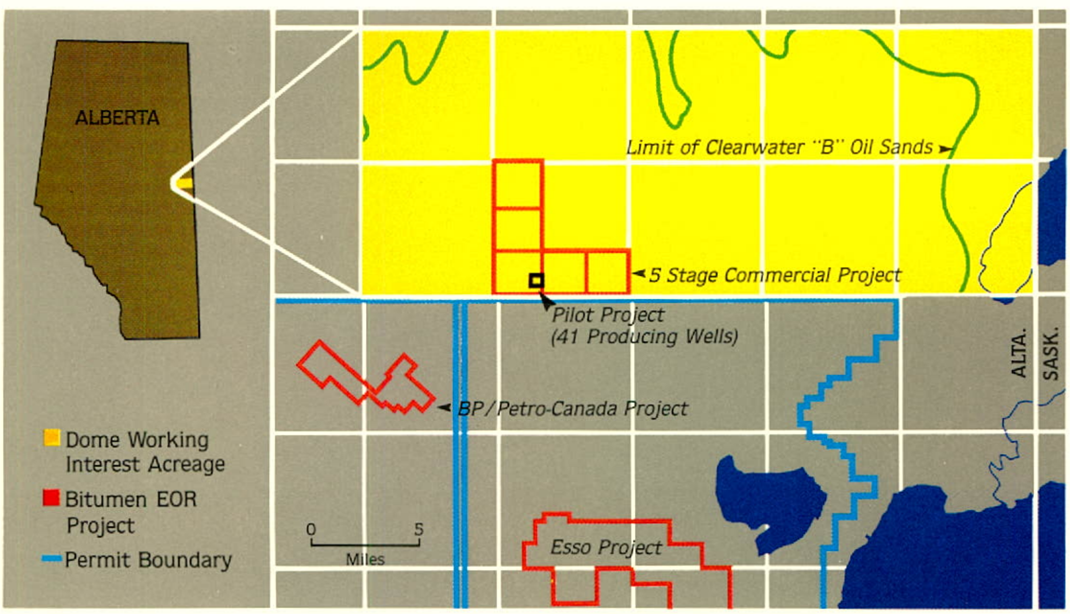
At Lindbergh, in the Lloydminster area of Alberta, the Company and other participants are operating two separate heavy oil enhanced recovery projects whereby two thermal techniques of cyclic steaming and in situ combustion with air and oxygen are being demonstrated. The Company and its partners intend to incorporate these two projects within a planned commercial development project.

The project is expected to raise area production at Lindbergh to an average 15,000 barrels of oil per day by 1989 from the 1984 level of 6,591 barrels per day. Agreement on fiscal terms for development has been reached with the Government of Alberta and an application for a commercial project is to be submitted to the Alberta Energy Resources Conservation Board (ERCB), with construction of new facilities and drilling expected to begin in 1985. Dome's working interests in the Lindbergh area range from 28% to 40%.

In the Primrose area of northeastern Alberta, Dome is earning a working interest in certain oil sands leases from Alberta Energy Company (AEC). Following extensive exploration, the Company undertook an enhanced recovery pilot project in the area, which commenced production in November, 1983, and thereby earned an interest in eight sections of adjoining oil sands leases. The agreement with AEC contemplates that Dome can earn an interest in an additional 225,000 acres of adjoining oil sands lands through development of a commercial production project.

Dome has proposed a 25,000 barrel per day commercial project to AEC, and intends to make application for approval of the project to the ERCB during 1985. The project is subject to the approval of AEC and regulatory authorities and the establishment of an appropriate fiscal regime.

In January, 1984, the Company entered into an agreement with two Canadian oil and gas companies which permits those companies to earn a total of 25% of Dome's interest in the Primrose pilot recovery project and the proposed commercial production facility. Under the agreement, the two companies have reimbursed Dome for approximately $20 million of its costs for the pilot recovery project and will pay one half of future expenditures on the commercial production project. The two companies also have the right to earn a 15% working interest in any subsequent projects for the recovery of bitumen from the AEC lands.



Primrose Area

Natural Gas

During 1984, 551 million cubic feet per day of natural gas were sold, a 19% increase over Dome's 1983 Canadian production volumes. The growth was attributable to improved markets for the industry, both in Canada and the United States, and to an increase in Dome's market share to 7.8% in 1984 from 7.1% in 1983. Alberta accounted for 90% of the Company's natural gas production.

Dome has developed natural gas reserves under contract capable of delivering up to approximately 860 million cubic feet per day as a maximum daily rate. Thus, even allowing for seasonal fluctuations in sales, it believes it is well positioned to take advantage of near-term market improvements through sales to existing purchasers, and also through additional direct marketing efforts.

During the year, 48% of Dome's natural gas production was sold to TransCanada PipeLines Limited, 38% to other gas purchasing and marketing companies and 14% directly to users in Alberta. It intends to continue to increase direct sales within Alberta, where a major portion of the 1984 increases were achieved. All natural gas production currently sold outside Alberta is marketed under long-term contract to gas purchasing and marketing companies, which allocate demand among their contracted suppliers.

Total industry natural gas exports to the United States increased 6% in 1984 due to a higher level of total demand and more competitive pricing of Canadian natural gas. On November 1, 1984, a new Canadian gas export policy became effective permitting negotiated pricing for natural gas exports. Under this policy, virtually all Canadian exporters of natural gas have re-negotiated export prices to competitive levels. The U.S. imported approximately 4% of its natural gas from Canada in 1984.

The volume of natural gas exported to the United States is expected to increase in 1985, although at prices lower than those achieved in 1984.

Dome is a major operator of natural gas plants in Canada. In 1984, it operated 17 plants, each with capacity in excess of 25 million cubic feet per day, plus 41 smaller licenced facilities. In 1984, plant outlet gas processed in Company-operated plants and facilities totalled 882 million cubic feet per day, amounting to 12.5% of industry production.

Industry Sales of Canadian natural gas

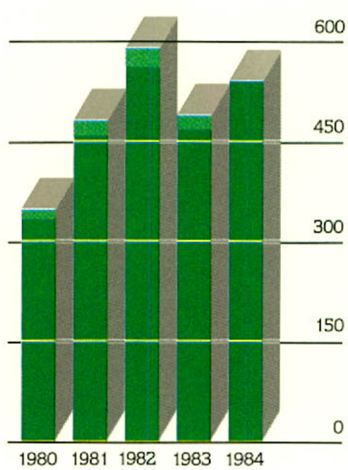
	1984	1983	1982
	(Millions of Cubic Feet per Day)		
Domestic market	**4,986**	4,572	4,784
Export market	**2,063**	1,951	2,147
Total	**7,049**	6,523	6,931
Dome natural gas sales	**551**	464	557
Market share	**7.8%**	7.1%	8.0%

Natural Gas Production

Millions of Cubic Feet per Day

Foreign

Canada



Dome's Major Oil Properties and Natural Gas Facilities

Conventional Oil Producing Properties	1984 Production Barrels Per Day
Pembina	6,047
Grand Forks/Hays	5,096
Willesden Green	3,648
Zama/Shekilie/Amigo	3,402
Fenn/Big Valley	2,746
Kaybob South	2,381
Sundre	1,347
Sturgeon Lake South	1,250
Garrington	1,210
Sylvan Lake	1,164
Medicine River	1,144
Cessford	1,100

Gas Production Facilities	1984 Production Million Cubic Feet Per Day
Brazeau	28.0
Provost/Consort	27.9
Edson	25.5
Goodfare	24.7
Kaybob	20.7
Willesden Green	19.9
Vulcan	16.8
Brownfield	16.2
Caroline North	14.4
Laprise Creek	13.6
Chinchaga	13.2
Cessford	10.1

Frontier Operations
Beaufort Sea

The primary area of activity by Dome on lands which are subject to federal government jurisdiction (Canada Lands) has been offshore in the Beaufort Sea. The emphasis to date has been on wildcat drilling and in meeting drilling and earning commitments in order to retain or earn exploratory acreage. At December 31, 1984, the Company held 12.2 million gross acres (5.9 million net acres) in this area. The Canada Oil and Gas Act vests in the Canadian government the right to a 25% interest in these Canada Lands, but the government is reviewing its policy with respect to its rights to this interest.

The drilling program in the Beaufort Sea commenced in 1976 and to the end of 1984 Dome had participated in 25 wells directly and through farmout. Of these wells, 10 were oil wells, four were gas wells and nine were dry holes. The two remaining wells were in progress at the end of the 1984 season.

Dome's 1984 costs of drilling on its lands in the Beaufort Sea were borne by Dome Canada and Home under farmout agreements. During 1984, the five wells not completed in 1983 were drilled to total depth. Two additional wells were spudded in which Dome has an interest. The five wells were drilled by the Company's drillships while the remaining two were drilled by another contractor.

Results of the 1984 program were: Natiak O-44 and Aiverk 2I-45 were dry and abandoned; Siulik I-05 was a non-commercial oil well and was abandoned; testing of Arluk E-90 was suspended until the 1985 season due to ice conditions; and a mechanical problem with the wellhead delayed testing of Havik B-41 until the 1985 drilling season. E. Nerlerk J-67 has not yet been drilled to total depth and the W-Tarsiut P-45 oil discovery was drilled by another operator on lands in which the Company has an interest. The Company did not retain the option to earn interests in the Natiak O-44 and Havik B-41 wells, but continues to hold working interests in lands immediately adjacent to these locations.

Sufficient delineation wells have not yet been drilled on any one structure which would enable the Company to determine whether any of the discoveries made to date will be commercial.

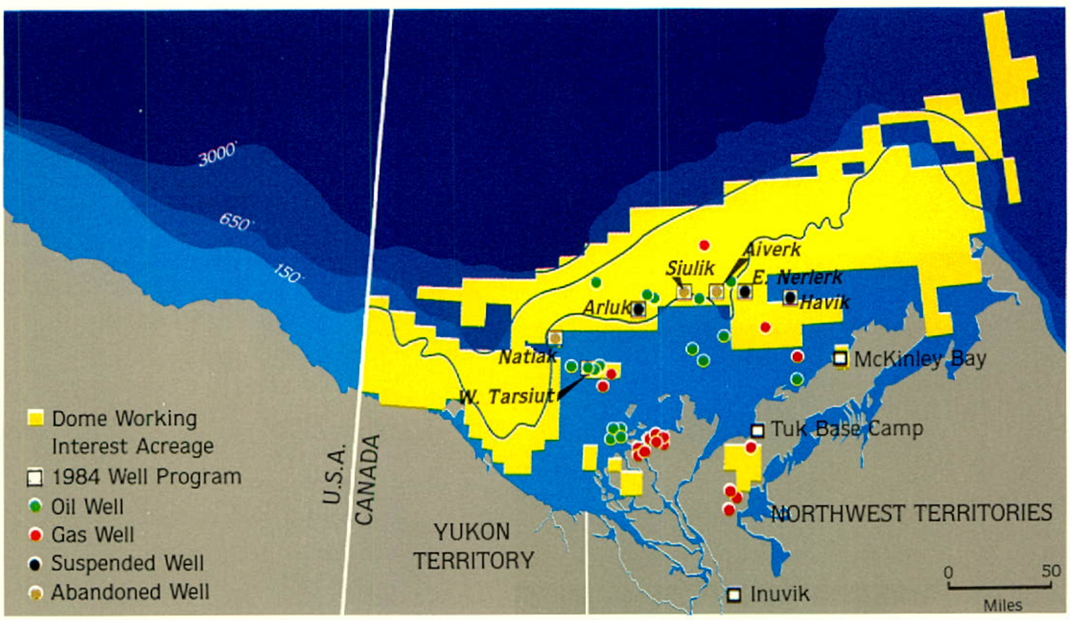
Other Canada Lands

The Company also has land interests off Canada's East Coast; in the Northwest Territories (NWT); and in the Arctic Islands, and farmed out a portion of its interests in wells drilled in these regions in 1984.

Dome entered into a farmout agreement in 1983 for the drilling of one well, with an option for two additional wells, offshore Nova Scotia. The first well was declared a non-commercial gas discovery in October, 1984 and was abandoned. The farmee has elected to drill the first of two additional wells. If three wells are drilled, Dome's 43.8% working interest in these lands will be reduced to 21.9%.

In the NWT in 1984, six wells in which the Company retained a working interest were drilled under farmout. One of these wells was a gas discovery, one a gas and condensate discovery which is currently being delineated, and the remaining four wells were dry.

In the Arctic Islands, in 1984, Dome participated in drilling two wells (one gas, one dry) through farmout of its working interest. Additionally, the Company holds a 6.2% interest in Panarctic Oils Ltd., a petroleum exploration company active in the Arctic Islands.



Beaufort Sea Area

Straddle plants, such as the Empress plant pictured here, supplied about 30% of the 110,000 barrels per day of natural gas liquids sold by Dome during the year.

Dome is the largest marketer of NGL in Canada and one of the largest in North America. Its fully integrated supply, transportation, storage, processing and marketing facilities give Dome a unique position in the industry.

Prices during 1984 trended lower due to softening international oil prices. Warm weather in late 1984 and lower demand for petrochemicals had an adverse effect on NGL sales volumes. Operating income declined 28% (of which a one time payment from Columbia LNG Corporation amounted to 17%) from 1983 levels mainly as a result of lower revenues and reduced margins on purchased products.

Although the Company expects to maintain its position in NGL marketing in Canada, it is probable that 1985 NGL operating income will continue to be affected by adverse price and market conditions.

Company Hortonspheres in Edmonton store NGL. Dome's extensive storage facilities for liquids, both underground and aboveground, help assure delivery to customers at times of peak demand.

Natural Gas Liquids Operations

Dome is a major participant in NGL purchasing, production, processing, transportation and marketing. Its NGL operations include various interests in two integrated systems of extraction plants, gathering systems, storage facilities, pipelines and fractionation plants. In 1984, this business segment provided $158.5 million (20%) of the Company's operating income.

The Company believes its NGL facilities are sufficiently developed to enable the Company to maintain its NGL operations with a relatively low level of future capital expenditures. Capital expenditures for NGL operations totalled $13.5 million in 1984.

Marketing and Supply

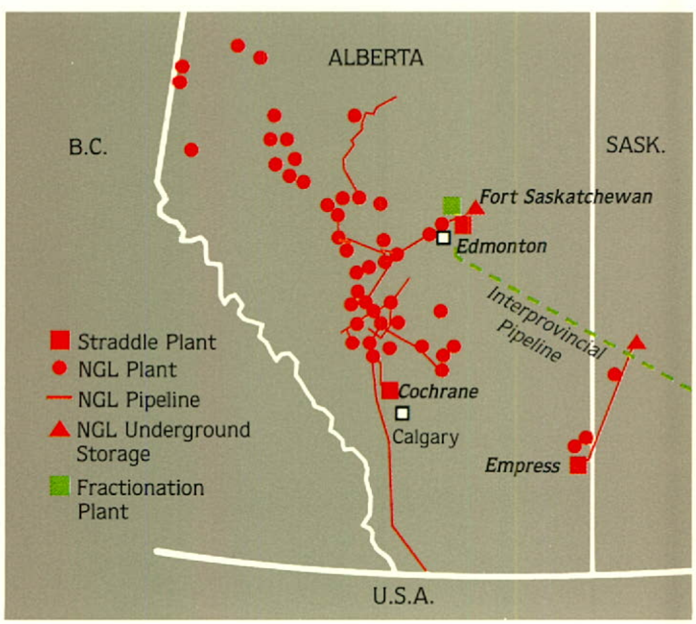
The size and flexibility of the NGL facilities enable Dome to deliver or arrange exchanges of its NGL in different geographic markets upon relatively short notice. The facilities include major operations at Edmonton and Empress, Alberta and Sarnia, Ontario; propane storage at St. Clair, Michigan; five propane terminals on the Cochin Pipeline; two connections to the Mid-America Pipeline; and other large storage facilities aggregating 15 million barrels.

Prices for NGL during 1984 were on a downward trend due to lower crude oil prices. Warm weather in late 1984 and low demand for petrochemicals had an adverse effect on the NGL sales volumes. These market conditions resulted in lower revenues and margins. In 1984, 48% of NGL sales were to markets in Canada and the balance to U.S. markets.

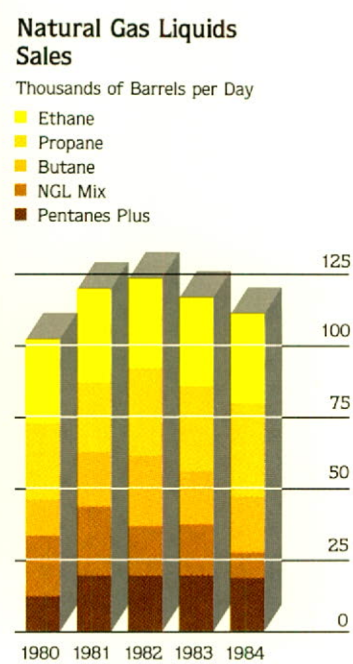
The bulk of the raw material for the NGL operations comes from sources other than reserves owned by Dome. Of the 110,000 barrels per day of NGL sold in 1984, the major sources of supply were mixed liquids and specification product from the Company's oil and gas operations and purchases from other producers (76,000 barrels per day) and from its straddle plant production (34,000 barrels per day).

Dome's production of NGL from straddle plants is dependent upon the total volume of natural gas production in Alberta, which increased in 1984. Dome has contractual rights, ranging from 13 to 25 years, to extract NGL from gas streams at straddle plants.

During 1984, the ERCB approved construction of two plants to extract NGL upstream of Dome straddle plant facilities. Such facilities could potentially reduce the NGL supply available to the Company.



NGL System



NGL System

The NGL system includes integrated extraction facilities (including straddle plants), the Co-Ed gathering pipeline, and storage facilities in Alberta and storage, fractionation and distribution facilities in eastern Canada and the eastern United States.

The eastern portion of the system is centred on a large capacity fractionation and distribution complex at Sarnia, Ontario, which is owned approximately 50% by Dome. In 1984, this facility produced an average 40,100 barrels per day of propane, 27,000 barrels per day of butane, 7,000 barrels per day of NGL mix and 19,500 barrels per day of pentanes plus and has storage capacity of 5.2 million barrels.

Alberta Ethane Gathering System and Cochin Pipeline System

Dome is the operator and one-third participant in both the 530 mile Alberta Ethane Gathering System and the 1,870 mile Cochin Pipeline System. During 1984, the Cochin Pipeline System operated at about 88% of its normal capacity during winter and at 55% of its normal capacity during summer.

A large volume of ethane is sold through this system to Columbia LNG Corporation for use in manufacturing synthetic natural gas. Columbia's need for this feedstock has been substantially reduced and as a result, in 1983, Dome and Columbia amended the supply contract for NGL, providing for reductions in price and quantities supplied. The amendments resulted in an estimated $27 million reduction in 1984 operating income.

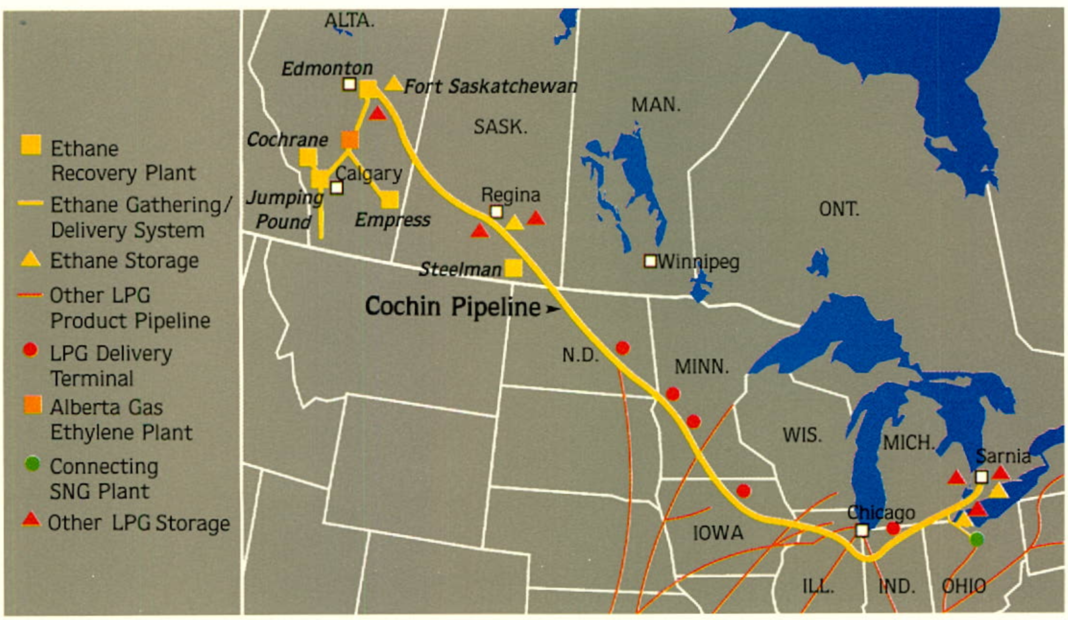
A three year renewable agreement has been entered into with a Canadian company for the sale of approximately 15% of the NGL previously sold to Columbia. In addition, agreements have been entered into with other Canadian companies for the sale of ethane for use in enhanced oil recovery projects in Alberta.

Other Pipeline Systems

Dome owns and operates the 962 mile Rangeland Pipeline System in Alberta, the 1,400 mile Producers-Westspur system in southeastern Saskatchewan, and holds a 16% interest in the Peace Pipeline in Alberta.

Sulphur

In 1984, sales volumes increased by 55% to 1,721 long tons per day. Contracts which are in place resulted in the entire production for 1984 and 1985 being sold, plus sales from inventory. The average price received for sulphur in 1984 was 42% higher than the average for 1983, and has continued to rise in 1985 over 1984 levels.



Alberta Ethane Gathering System and Cochin Pipeline

Four ships of Dome's contract drilling fleet, including icebreaker Robert Lemeur and drillship Explorer 2, are on contract to drill an exploratory well in the U.S. Beaufort in summer of 1985.

As a consequence of reduced fleet utilization, 1984 operating income was lower than that achieved in 1983. The mobile Arctic drilling vessel, the SSDC, was not contracted for the second half of 1984.

During the 1984 drilling season, the four drillships were fully contracted, returning to five 1983 locations for drilling and testing. Testing was not completed at two locations and the Company expects to return to those locations in 1985 and is discussing further drilling locations with various participants.

In October, 1984, the Company announced its first joint venture drilling contract for offshore Alaska. Under this contract, one of the drillships, supported by three other vessels, was moved to location in the U.S. Beaufort Sea in 1984, where a well will be drilled during the 1985 season. Contracts are being pursued for the remaining drillships and the SSDC. Revenues and operating income in 1985 are expected to be lower than 1984.

Artist's rendering shows relocatable mat system designed to improve economics of drilling using Dome's SSDC mobile Arctic drilling vessel. Engineering design of the mat system is being developed for a major U.S. oil company.

Contract Drilling Operations

Dome has been contract drilling in the Beaufort Sea region of northern Canada since 1976 under the name Canmar and owns a fleet of drilling and support vessels and shore base facilities. During 1984, this business segment generated 14% of Dome's total operating income.

The drilling fleet consists of four drillships and a mobile Arctic drilling vessel, the SSDC, which are supported by two class 3 icebreakers, four Class 2 supply ships and a variety of other vessels. Services and materials are supplied to the drilling operation from a shorebase at Tuktoyaktuk, while the fleet operates out of McKinley Bay, a medium draft harbor constructed by the Company.

Open water drilling operations in the Beaufort Sea in 1984 were hampered by an unusual mid-season intrusion of polar pack ice over the four most northerly drillsites. The SSDC operated under contract to Gulf Canada until July and then was demobilized.

In 1985, two of the drillships are expected to return to complete the evaluation of the Havik and Arluk wells in the Canadian Beaufort Sea. As is normal in the contracting industry, it is difficult to predict utilization levels for the drilling fleet due to dependence upon a variety of factors including drilling results, government incentives, fiscal terms and economic conditions.

To lessen its dependence on the Canadian Beaufort Sea drilling market, Dome is pursuing additional markets for its contract services in the U.S. Beaufort Sea, which has an ice environment and water depths similar to Canmar's historical operating area.

In January, 1984, the Company announced a joint venture agreement with Reading & Bates Drilling Co., a U.S. based drilling contractor, through which Dome's drilling vessels are being made available for drilling in the U.S. Beaufort Sea and other areas outside the Company's interests in the Canadian Beaufort Sea. Under this contract, one of the Company's drillships, supported by an icebreaker and two supply vessels, was moved to the U.S. Beaufort Sea in 1984, where it will drill one well during the 1985 season. The joint venture is pursuing contracts for the SSDC in the 1985-87 time frame.

Canmar Fleet and Facilities

Fleet

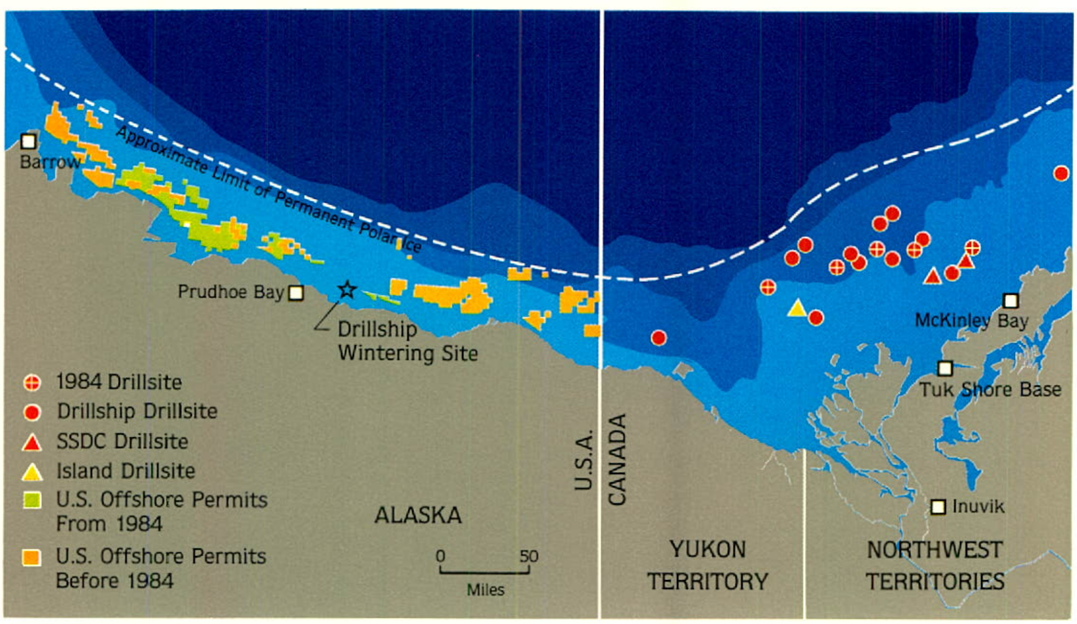
4 drillships
1 mobile Arctic drilling vessel (SSDC)
2 class 3 icebreakers
1 seismic vessel
7 supply vessels
3 tug-boats
2 standby vessels
1 high speed crew boat
9 barges.

Tuktoyaktuk ("TUK") Shore Base

Beaufort operating headquarters
Communications network
Air Services
Environmental protection services

McKinley Bay

Deep water harbor
Floating drydock and repair facility
Air-strip



Contract Drilling - U.S./Canadian Beaufort Sea

Associated Companies and Other Assets

Dome Canada Limited

Dome Canada was formed by Dome in 1981 to explore for oil and gas and was structured to qualify for exploration and development incentives under the federal government's National Energy Program. The program provides cash incentives of up to 80% of defined eligible exploration expenditures for companies with high Canadian ownership. Dome's interest in Dome Canada is 48%.

Under the DELA farmout Dome Canada has access to most of the Company's exploratory acreage. Proposed revisions to the agreement allow for development drilling by Dome Canada on the Company's western Canadian lands.

The DELA provides for the management of Dome Canada's oil and gas operations and administrative functions by Dome, for which the Company received fees of $23.4 million in 1984.

Exploration and development expenditures by Dome Canada in 1984 amounted to $167.2 million, net of PIP grants. Dome Canada's net income for 1984 was $32.4 million compared with net income of $7.1 million in 1983, which was negatively affected by a writedown of frontier assets, partially offset by a gain on the sale of a long term investment. Revenues totalled $188.7 million, compared to $133.3 million in 1983, and funds generated from operations were $134.9 million compared to $103.8 million in 1983. Dome Canada had assets at December 31, 1984 of $1,435.5 million.

Dome Mines Limited

Dome Mines and its operating subsidiaries, Campbell Red Lake Mines Limited and Sigma Mines Limited, are principally in the business of mining and milling of, and exploration for, gold bearing ore to produce gold bullion. Dome Mines owns 56.9% of the common shares of Campbell Red Lake Mines and 65.2% of the common shares of Sigma Mines. These companies in the aggregate produced 430,676 ounces of gold in 1984.

At December 31, 1984, Dome owned 30.9 million (38.3%) of the common shares of Dome Mines, making it Dome Mines' principal shareholder.

At December 31, 1984, Dome Mines owned, directly and indirectly, 24% of the common shares of Dome and is its principal shareholder.

Dome Mines reported revenue in 1984 of $215.1 million and income of $30.0 million before deducting Dome Mines' equity interest in the loss of the Company. Dome Mines's net loss for 1984 was $25.7 million.

Cyprus Anvil Mining Corporation

Dome owns an 87½% interest in Cyprus Anvil Mining Corporation, which owns an open pit zinc-lead-silver mine located near Faro, Yukon Territory.

Operations have been suspended at the mine since June, 1982 due to depressed economic conditions and high operating costs. An overburden removal program which began in June, 1983 was suspended in October, 1984 due to a labor dispute. Cyprus is seeking significant labor cost reductions.

Commencement of production is dependent upon the implementation of operating cost efficiencies and the resolution of transportation, electrical power and labor issues. The Canadian government is assisting Cyprus in its attempts to resolve these issues. Dome intends to sell its interest in Cyprus.

Dispositions

During 1984 the proceeds of dispositions totalled $138.8 million. Principal dispositions were as follows:

In September, 1984, the Company completed the sale of its interest in Sovereign Oil & Gas PLC for $40 million.

Effective November, 1984, Dome sold its interest in Les Mines Selbaie Ltee., a copper-silver-gold mine in northwestern Quebec, for $16.6 million.

Effective November, 1984, the Company completed the sale of its interest in approximately 25,000 acres in the Suffield Military Range in southeastern Alberta for $19.3 million.

In March, 1985, the Company sold all of its shares in Davie Shipbuilding Limited for nominal consideration.

Financial Review

Selected Financial Data

The following selected consolidated financial data of Dome Petroleum, as it relates to the years ended December 31, 1980, 1981, 1982, 1983, and 1984, is derived from the consolidated financial statements of the Company examined by Clarkson Gordon, independent chartered accountants.

	Years Ended December 31,				
	1984	1983	1982[1]	1981[1]	1980
	(Millions of Canadian Dollars, Except Per Share Amounts)				
CONSOLIDATED FINANCIAL DATA [2] [3]					
Revenue	**$2,447.6**	$ 2,594.6	$ 2,849.8	$ 2,172.3	$1,121.2
Operating income[4]	**780.3**	758.7	826.9	747.2	468.0
Foreign exchange gain (loss)	**(123.0)**	(26.6)	(22.6)	(11.1)	4.0
Write-down of assets	—	(1,099.0)	(213.6)	—	—
Associated deferred income taxes	—	202.1	—	—	—
Gain (loss) on disposal of assets	**39.8**	(65.0)	(154.6)	18.3	0.3
Associated deferred income taxes	**(9.8)**	(11.6)	54.2	(6.7)	—
Net income (loss)	**(196.8)**	(1,105.0)	(369.3)	199.1	287.2
Net income (loss) per common share[5]	***(0.84)***	*(4.72)*	*(1.71)*	*0.80*	*1.20*
Dividends declared per common share	—	—	—	—	—
Working capital (deficiency)	**(81.1)**	(2,740.9)	(2,572.9)	(5.6)	158.6
Total long term debt	**$ 6,302.8**	$ 5,987.3	$ 6,521.1	$ 6,394.5	$2,705.4
Less portion due within one year	**205.3**	2,236.5	2,228.5	150.7	59.2
Redeemable preferred shares	**317.9**	317.9	322.9	384.6	379.6
Long term obligations	**$ 6,415.4**	$ 4,068.7	$ 4,615.5	$ 6,628.4	$3,025.8
Shareholders' equity (deficiency)	**(420.1)**	(230.5)	841.2	1,190.0	1,009.8
Total assets	**7,915.7**	8,178.0	9,916.6	10,208.7	5,078.7

(1) The financial results for 1982 include the consolidation of HBOG, less minority interest of 47.1% with respect to net income for the two months ended February 28, and the consolidation of 100% of HBOG for the remainder of the year, after reflecting the acquisition by others of approximately a 34.1% interest in HBOG on March 10, 1982. The results for 1981 include the consolidation of HBOG subsequent to June 1981, less minority interest of 47.1% with respect to net income.

(2) The financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada. These principles differ in some respects from those applicable in the United States (see Note 21 to the consolidated financial statements). If the financial statements had been prepared in accordance with accounting principles generally accepted in the United States, certain of the selected financial data would be restated as follows:

	Years Ended December 31,				
	1984	1983	1982	1981	1980
	(Millions of Canadian Dollars, Except Per Share Amounts)				
Net income (loss)	**$ (270.5)**	$ (756.5)	$ (413.5)	$ 243.9	$ 291.4
Net income (loss) per common share[5]	***(1.14)***	*(3.24)*	*(1.91)*	*1.00*	*1.21*
Foreign exchange gain (loss)	**(190.6)**	(28.6)	(67.5)	9.0	(3.5)
Write-down of assets	—	(645.6)	(213.6)	—	—
Long term obligations (including redeemable preferred shares)	**6,524.3**	4,181.5	4,803.3	6,746.8	3,186.4
Redeemable preferred shares	**426.8**	430.7	440.1	504.5	502.7
Shareholders' equity (deficiency)	**(243.0)**	16.4	737.2	1,127.7	897.3
Total assets	**8,252.8**	8,582.7	9,915.2	10,203.3	5,077.4

(3) The above amounts reflect certain changes in accounting policies adopted in the five year period reported on (see Note 2 to the consolidated financial statements).

(4) Operating income is after operating expenses, depletion, depreciation and amortization but before corporate expenses and before write-downs and loss on disposal of assets (see Note 18 to the consolidated financial statements).

(5) Per share amounts have been restated to reflect the Company's five for one share split during 1981.

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

Results of Operations

The Company incurred a net loss of $196.8 million in 1984 as compared with a net loss of $1,105.0 million in 1983. The losses for the two years were caused by different factors as discussed below. The 1984 loss included foreign exchange losses of $109.9 million, and other costs of $66.8 million relating to the rescheduling of debt and interest on income taxes of HBOG (see 'Financing Expense' below). The foreign exchange losses and other costs are net of deferred income taxes of $13.1 million and $27.1 million respectively. The 1984 net loss also includes the effect of lower capitalized interest, higher depletion, depreciation and amortization and higher interest on long term debt, partially offset by gains on disposal of assets. Effective December 31, 1984, $5.3 billion of the Company's long term debt and certain other current liabilities were rescheduled over periods of up to 12 years, which resulted in an improvement of $2.7 billion in the Company's working capital position (see 'Liquidity and Capital Resources'). The transfer of $2.3 billion of current debt to long term significantly reduces the impact on the Company's current operations of fluctuations in exchange rates under Canadian generally accepted accounting principles. Under United States generally accepted accounting principles, foreign exchange gains or losses are included in income on a current basis.

Total operating income (before write-down and gain (loss) on disposal of assets which mainly affected 1983) increased $21.6 million in 1984. An increase in the Company's oil and gas segment operating income offset declines in the natural gas liquids and contract drilling segments.

In 1983, Dome Petroleum incurred a net loss of $1,105.0 million primarily as a result of write-downs aggregating $896.9 million, net of deferred income taxes of $202.1 million, and losses on disposal of certain assets of $76.6 million, including $11.6 million of deferred income tax expense. The Company wrote down its mineral, shipbuilding and certain other assets by $438.7 million, net of deferred income taxes of $25.0 million, to estimated realizable values as a result of its stated intention to dispose of these assets. This write-down included portions of the Company's interest in Cyprus, Davie and Selbaie. Dome Petroleum's Beaufort, Arctic and East Coast oil and gas exploration costs were written down by $316.6 million, net of deferred taxes of $136.8 million, in conjunction with the establishment of a separate cost centre (see Note 2 to the consolidated financial statements). This write-down included costs related to dry holes and two non-commercial gas wells. The remaining frontier costs incurred by the Company, which to December 31, 1983, amounted to $332.6 million, are being amortized over a period of fifteen years commencing January 1, 1984 unless commercial reserves are proved or abandonment occurs. The Company's United States oil and gas assets were written down by $97.9 million at June 30, 1983, and a further $72.8 million loss was recorded at December 31, 1983, as a result of the sale of these assets to Texaco. In addition, the Company wrote off certain financing, project and other costs in the amount of $43.7 million, net of deferred income taxes of $40.3 million.

In addition to the effect of write-downs and loss on disposal of assets, a number of other factors contributed to the increase in the Company's loss in 1983 over its loss in 1982. These factors included: an increase in depletion, depreciation and amortization; a one time gain in 1982 on cancellation of preferred shares and fees related to HBOG; lower capitalized interest; a higher provision for income taxes before the income tax effects of the write-downs and losses on disposal of assets are taken into account; and lower equity earnings as a result of Dome Canada's write-down of certain of its frontier costs. These factors were partially offset by lower interest costs on long term debt and lower preferred share dividends of subsidiaries.

In 1982, the Company reported a net loss of $369.3 million, which included a $213.6 million write-down of its United States oil and gas assets as a result of a decline in United States oil and gas prices and property values, and a loss of $100.4 million, net of deferred income taxes of $54.2 million, on the sale of the Company's oil and gas assets which were located outside of North America. Other factors contributing to the loss were high interest costs and preferred share dividends of subsidiaries, both of which were associated with the acquisition of HBOG.

The following is a discussion and analysis of the results of operations for the Company's three business segments during the past three years. The Company's revenues and operating income attributable to its business segments during these periods were as follows (see Note 18 to the consolidated financial statements):

	Year Ended December 31,		
	1984	1983	1982
	(Millions of Canadian Dollars)		
Revenue			
Crude oil and natural gas	**$1,088.3**	$ 946.4	$1,003.8
Natural gas liquids	**1,012.5**	1,135.4	1,044.3
Contract drilling	**335.7**	409.3	505.7
Other operating	**11.1**	103.5	296.0
	$2,447.6	$ 2,594.6	$2,849.8
Operating income before write-down and gain (loss) on disposal of assets			
Crude oil and natural gas	**$ 532.4**	$ 437.2	$ 516.7
Natural gas liquids	**158.5**	219.8	214.2
Contract drilling	**112.2**	145.6	153.2
Other operating	**(22.8)**	(43.9)	(57.2)
	$ 780.3	$ 758.7	$ 826.9
Write-down and gain (loss) on disposal of assets (other than corporate)			
Crude oil and natural gas	**$ 0.4**	$ (667.2)	$ (355.3)
Natural gas liquids	**0.7**	—	—
Contract drilling	**2.3**	(12.0)	—
Other operating	**6.2**	(459.5)	(10.9)
	$ 9.6	$(1,138.7)	$ (366.2)

Crude Oil and Natural Gas

The Company's crude oil and natural gas revenues increased 15% in 1984 and operating income for this business segment was up 22% from 1983 levels mainly as a result of higher oil prices and increased gas volumes. This growth was achieved in 1984 despite the absence of United States oil and gas production, and higher amortization expense caused by the commencement of frontier area cost amortization.

The Company's total crude oil production in 1984 remained at virtually the same level as in 1983, as production from new sources together with productivity improvements offset declining productivity in older fields and the absence of United States production. The Company's Canadian crude oil production increased 6% during 1984. Higher average oil prices in 1984 as compared with 1983 resulted from a greater proportion of the Company's production qualifying for world price.

The Company's Canadian natural gas production increased 19% in 1984 mainly due to higher domestic and export demand. While export prices for natural gas declined in 1984 and domestic prices remained stable, higher domestic and export volumes resulted in reduced pipeline tariffs and increased export flowback. Sulphur and other revenues increased in 1984 to $69.7 million from $15.4 million in 1983 primarily due to significantly higher prices and volumes.

Natural gas liquids revenues from Canadian field operations were higher due to volumes from the new West Pembina Plant, which commenced production in mid-1984, and from increased prices.

The Company expects that the volume of natural gas exported to the United States will increase in 1985, although at prices lower than those received in 1984. Over the longer term, the United States is expected to provide growing market opportunities for Canadian natural gas. The Company expects modest improvement in its oil and field NGL production in 1985. However, prices may be affected by uncertainty in world oil markets and the outcome of the current regulatory review by the Canadian and provincial governments.

In 1983, the Company's revenues from crude oil and natural gas declined $57.4 million from 1982 levels as a result of a number of factors. The effect of reporting a higher proportionate share of HBOG production for the first two months of 1982 resulted in a decline of $36.3 million in 1983. Crude oil revenues increased due to the effect of higher sales prices which were partially offset by sales volume reductions mainly attributable to the full year effect of the disposition of the Company's foreign oil and gas assets in mid-1982 and lower United States oil production. The Company's natural gas sales volumes declined in 1983 due to reduced demand for natural gas in Canada and the United States. Although the domestic market price for Canadian natural gas increased and royalties declined in 1983, these positive factors were almost entirely offset by reduced prices for exports to the United States and higher per unit pipeline tariffs as a result of reduced volumes. Field NGL revenue increased due to higher prices which were partially offset by volume reductions reflecting lower natural gas production from which this NGL is extracted. Sulphur revenues in 1983 declined from 1982 levels due to large sales from inventory in 1982. The 1983 decline in operating income of $79.5 million from 1982 was primarily attributable to reduced revenues and higher depletion, depreciation and amortization.

Natural Gas Liquids

The Company's NGL revenues from the operation of its pipeline systems and from the sale of NGL produced by straddle plants or purchased from producers for 1984 declined 11% from prior year levels due to lower prices and volumes for several NGL products. The decline included reductions as a result of changes to the Company's contract with Columbia LNG Corporation ('Columbia') and a one-time payment in 1983, which totalled $36.4 million, from Columbia for contracted volumes not taken. Prices during 1984 were on a downward trend due to lower international oil prices. Warm weather in late 1984 and low demand for petrochemicals had an adverse effect on NGL sales volumes. Operating income declined 28% (of which a one-time payment from Columbia amounted to 17%) from 1983 levels mainly as a result of lower revenues and reduced margins on purchased products. In 1985, the Company expects that NGL operating income will continue to be affected by adverse price and market conditions.

In 1983, NGL revenues increased $91.1 million over 1982, primarily due to increased prices ($97.2 million) and a one-time payment of $36.4 million from Columbia in settlement of an obligation for contracted volumes not taken. These increases were offset in part by volume decreases amounting to $54.0 million. Volume decreases were attributable to lower NGL supplies resulting from lower natural gas production and, to a lesser degree, to reduced demand for certain products. Despite increased total sales of NGL, operating income remained at a level similar to 1982, mainly due to reduced margins on the sale of purchased products, offset by the one-time payment by Columbia.

Contract Drilling

The Company's contract drilling revenues and operating income for 1984 were 18% and 23% lower, respectively, than those of the prior year period, reflecting reduced fleet utilization during 1984 as compared with 1983. These revenues are comprised principally of a capital charge on equipment, recovery of all operating expenses and a charge for overhead. The Company's mobile Arctic drilling vessel, the SSDC, was not contracted for the second half of 1984, which was the main reason for the reduced utilization. During the 1984 drilling season, the Company's four drillships returned to five 1983 locations for drilling and testing. Testing was not completed at two of the 1984 locations and the Company expects to return to those locations in 1985 and is discussing further drilling locations with other participants. In October 1984, the Company announced its first joint venture drilling contract in the U.S. Beaufort Sea. Under this contract one of the Company's drillships, supported by three of its other vessels, is scheduled to drill one well in the U.S. Beaufort Sea during the 1985 season. The SSDC has not been contracted for 1985. However, the Company is continuing to pursue contracts for its services. The Company expects 1985 revenues and operating income to be lower than 1984.

Beyond 1985, the Company is unable to predict the utilization level of its contract drilling assets due to dependence upon a variety of factors including drilling results, government incentives, fiscal terms and economic conditions relating to exploration activity in the Beaufort Sea.

The Company's contract drilling revenues in 1983 were $409.3 million compared to $505.7 million in 1982. A cost reduction program combined with a reduced island construction program in 1983 resulted in a decrease in operating expense and a corresponding decrease in revenue. Operating income was not significantly affected by the decrease in revenue, with a decline of $7.6 million mainly due to reduced overhead recoveries.

Other Operating

Other revenues and operating losses for 1984 were lower than prior-year levels because the Company discontinued consolidation of the operations of Cyprus and Davie at December 31, 1983 (see Note 1 — "Investments" to the consolidated financial statements).

The Company's 1983 revenues from other sources declined $192.5 million as compared to 1982, primarily as a result of reduced shipbuilding activity at Davie in the amount of $144.2 million and a $46.1 million decline in mining revenues, due to the shutdown of Cyprus during all of 1983.

Financing Expense

The following table summarizes the Company's financing expense for the last three years:

	1984	1983	1982
	(Millions of Canadian Dollars)		
Interest on long term debt	**$710.8**	$679.3	$ 789.2
Other interest and financing charges	**163.5**	71.0	67.2
	874.3	750.3	856.4
Preferred share dividends of subsidiaries	**15.7**	34.1	163.5
Gross financing cost	**890.0**	784.4	1,019.9
Less: Capitalized interest	**51.7**	136.8	212.9
Net financing expense	**$838.3**	$647.6	$ 807.0

Gross financing costs increased in 1984 from 1983 due to a number of factors. Higher interest and foreign exchange rates relative to those prevailing in 1983 caused an increase in interest on long term debt. Other interest and financing charges of $163.5 million in 1984 include costs of $93.9 million (before deferred income taxes of $27.1 million) consisting of: interest costs of $36.4 million relating to outstanding income taxes of HBOG (the Company received remission orders for such income taxes concurrently with the closing of the Debt Rescheduling Agreement); debt rescheduling fees paid to certain of the Company's lenders amounting to $31.8 million ($4.7 million in cash and $27.1 million in common shares of the Company); and advisory, legal and other costs of $25.7 million incurred by the Company relating to debt rescheduling.

Preferred share dividends of subsidiaries for 1984 declined from 1983 due to the redemption of the Dome Resources Limited Class A Preferred Shares in March, 1983. Capitalized interest in 1984 was lower as compared with 1983 due mainly to the cessation of capitalization of interest on frontier area costs commencing January 1, 1984.

Gross financing costs decreased $235.5 million in 1983 from 1982 levels, primarily as a result of a $129.4 million reduction in preferred share dividends of subsidiaries, due to the purchase and redemption of the Dome Resources Limited Class A Preferred Shares in 1982 and 1983, and a $109.9 million decline in interest payments as a result of lower interest rates and a net reduction of $533.8 million in the level of the Company's long term debt. Capitalized interest decreased $76.1 million in 1983, as a result of lower interest rates and a diminishing balance of non-depleted oil and gas properties upon which interest was capitalized.

Of the Company's total long term debt of $6,302.8 million as at December 31, 1984, including current portion, $877.9 million is at fixed rates. The remainder is at floating interest rates and consequently interest cost is directly affected by fluctuations in interest rates. The Company plans to fix the interest rates on a portion of its floating rate debt utilizing financial futures contracts and interest rate swaps, thereby reducing the impact of interest rate fluctuations.

Foreign Exchange

A decline of approximately U.S. $.05 in 1984 in the value of the Canadian dollar relative to the U.S. dollar caused most of the foreign exchange losses in 1984 of $123.0 million before deferred income taxes. To reduce the Company's exposure to future currency fluctuations, the Company converted approximately U.S. $712 million of long term debt to Canadian dollars in September 1984. With the rescheduling of the Company's debt effective December 31, 1984, foreign exchange gains or losses thereon will be deferred and amortized over the remaining term of the related debt under Canadian generally accepted accounting principles. There would be no comparable effect under United States generally accepted accounting principles, which require unrealized foreign exchange gains or losses on all long term debt to be recognized in income on a current basis.

While the Company incurred foreign exchange losses in 1984 with regard to its U.S. dollar denominated debt, these losses were partially offset by higher prices, in Canadian dollar terms, for exported natural gas and NGL products and for the portion of its oil production which qualifies for world price. In cash terms, these benefits moderately exceeded the increase in interest and principal payments on U.S. dollar denominated debt caused by the decline in the value of the Canadian dollar.

General and Administrative

The following table sets forth general and administrative expense and portions thereof which were capitalized during the past three years:

	1984	1983	1982
	(Millions of Canadian Dollars)		
General and administrative cost (net of recoveries)[1]	**$112.3**	$139.8	$152.5
Less: amount capitalized	**(29.4)**	(29.1)	(53.8)
Net general and administrative expense	**$ 82.9**	$110.7	$ 98.7

[1] The Company does not allocate general and administrative cost to operating expenses. Recoveries represent portions of general and administrative costs for which the Company receives reimbursement from others when it acts as operator or manager.

The Company is continuing its program of reducing general and administrative costs, which resulted in reductions of $27.5 million in 1984. The largest reductions were achieved by reducing staff levels, selling the Company's U.S. oil and gas operations and lowering office space costs through subleasing excess space, lease terminations and rental reductions. In September 1984, the Company reduced its employee savings plan share contributions and in December 1984, with the assistance of an outside consulting firm, commenced a detailed Company wide review of administrative functions and costs.

As a result of expense reduction programs undertaken by the Company in 1982 and 1983, the growth of general and administrative costs before capitalization was reversed in 1983. In September, 1982, the Company instituted a 10% general salary reduction and in 1983 limited salary increases to an average of 6%. The Company reduced head office staff levels in 1982 and 1983 through attrition and layoffs and introduced an early retirement program in late 1983. In addition, the Company has subleased a portion of its excess office space, consolidated its operations, and terminated certain building commitments. Offsetting these cost reductions in 1983 were settlement costs associated with discontinued building commitments and employment termination costs.

Despite efforts by the Company which resulted in a $12.7 million reduction in general and administrative cost from 1982, net general and administrative expense increased in 1983 because the capitalized portion of general and administrative expense declined by $24.7 million due to lower capital expenditures.

Income and Other Taxes (see Note 6 to the consolidated financial statements)

In 1984, the Company provided for income taxes of $38.1 million despite having recorded a loss before income taxes and equity earnings of $187.2 million for the year. This occurred primarily as a result of the non-deductibility for tax purposes of certain items, the most significant of which were PGRT, interest expense on overdue income taxes and PGRT, and depletion, depreciation and amortization related to the excess of the purchase price over the tax values of assets acquired.

The 1984 provision for income taxes includes a reversal of current income tax expense of $256.5 million in respect of the operations of HBOG for 1982 and 1983. This reversal resulted from the granting of remission orders by the Government of Canada and the Province of Alberta in connection with the closing of the Debt Rescheduling Agreement on February 5, 1985. These remission orders effectively permit the consolidation for tax filing purposes of HBOG and Dome Energy thereby permitting HBOG to deduct from its income for tax purposes costs incurred by Dome Energy relating to its acquisition of HBOG. Since the Company prepares its income tax provision on a consolidated basis and had therefore previously recognized for accounting purposes the tax benefit of the costs incurred by Dome Energy, the reversal of HBOG current income tax expense for 1982 and 1983 was offset by a corresponding increase in deferred income tax expense.There is no current income tax provision in respect of the 1984 operations of HBOG as the income from those operations continues to be offset by Dome Energy costs.

In 1983, the Company recorded an income tax reversal of $26.1 million which included previously recorded deferred income taxes aggregating $190.5 million, related to the write-downs and losses on disposal of certain assets. The income tax reversal was relatively small in comparison with the net loss incurred for the year before income taxes and equity earnings of $1,175.3 million mainly due to the non-deductibility for income tax purposes of certain items, the most significant of which were certain of the write-downs and losses on disposal of assets.

The 1982 income tax provision of $93.9 million was required even though the Company had incurred a loss before income taxes and equity earnings of $332.5 million largely as a result of the non-deductibility of certain items for income tax purposes. Principal among these items were the write-down of United States oil and gas properties, preferred share dividends of subsidiaries and PGRT.

In 1983, Revenue Canada issued reassessments to the Company disallowing the frontier exploration allowance claimed in 1980. Management believes that these amounts were validly claimed and intends to contest the issue. If the Company is not successful, a prior period adjustment will be made relating to 1980 which will increase the deficit and deferred income taxes by $44.3 million.

Effect of Changing Prices

For a discussion of the effects of changing prices on the Company's operations, reference is made to the unaudited supplementary information to the financial statements of the Company included in this document.

Liquidity and Capital Resources

Debt Rescheduling and Financial Condition

The Company's 1984 year-end financial position improved significantly as a result of the rescheduling of a large portion of its debt. On February 5, 1985 the Company and its lenders closed the Debt Rescheduling Agreement under which repayment of $5.3 billion of the Company's debt was rescheduled over a 12 year period extending to 1995. The Company's remaining long term debt of $1.1 billion, largely held by the public, is to be repaid on its original schedule. Principal payments due to the Company's lenders during the five years ending December 31, 1988 have been reduced by $3.6 billion.

Concurrently with the closing of the Debt Rescheduling Agreement, the Company received remission orders from the Government of Canada and the Province of Alberta with respect to current income taxes of HBOG. The Company reached agreement with Revenue Canada — Taxation extending payment of the Company's outstanding 1982 and 1983 PGRT obligations amounting to $204.1 million (including associated interest) at December 31, 1984 over a five year period commencing January 2, 1986. Payments will include additional interest at the rate prescribed by the Income Tax Act (Canada). An agreement was also reached with Dome Canada extending over a five year period commencing January 2, 1986, the repayment of $112.5 million owing to Dome Canada.

As a result of the foregoing debt rescheduling and related transactions, the Company's working capital deficiency was reduced by $2.7 billion and the Company's long term debt increased $2.7 billion at December 31, 1984.

During 1982, current maturities of long term debt, high interest rates and lower than anticipated revenues resulted in a severe cash flow shortfall which caused Dome Petroleum to approach its principal Canadian bankers and the Government of Canada for assistance. In September, 1982 the Company, its principal Canadian bankers, the Government of Canada and Dome Mines signed the Agreement in Principle ("AIP") which contemplated a rescheduling of the Company's debt repayment obligations and an issue of equity-related securities principally to Dome Petroleum's secured lenders and the Government of Canada. In the course of negotiating the implementation of the AIP, Dome Petroleum developed a debt rescheduling plan to replace the AIP, which plan was presented to its lenders on December 1, 1983. After considerable negotiation, the plan became the basis of the Debt Rescheduling Agreement which closed on February 5, 1985. The AIP expired on October 1, 1984 without any funds having been drawn thereunder.

Substantially all assets of the Company are either pledged as security for existing indebtedness, or are the subject of covenants in financial instruments whereby the Company's ability to give security on such assets is restricted (see Note 7 to the consolidated financial statements).

Under the Debt Rescheduling Agreement, Dome Petroleum has access to funds under two additional credit facilities. The Operating Credit Agreement provides that certain lenders will make available to Dome Petroleum up to $245 million in operating lines, subject to the level of acceptable receivables pledged by the Company pursuant to guidelines contained in the Operating Credit Agreement. The Operating Credit Agreement also provides that $150 million will be made available until February 6, 1986 irrespective of the level of pledged accounts receivable, but subject to compliance with certain conditions and financial tests.

Under the Secured Project Credit Agreement, certain lenders have agreed to make available Cdn. $200 million and U.S. $29 million secured by completed capital projects commenced after December 1, 1983. The acceptability of projects proposed by Dome Petroleum as security will be reviewed by the lenders under guidelines contained in the Secured Project Credit Agreement prior to any lending under this facility.

Other than amounts advanced pursuant to the Operating Credit Agreement and the Secured Project Credit Agreement, Dome Petroleum is prohibited under the Debt Rescheduling Agreement from incurring any additional indebtedness not expressly subordinated to the repayment of the rescheduled debt (with certain exceptions) unless the ratio of consolidated net earnings available for interest and dividend charges during the most recent reported twelve month period to pro forma annualized interest and dividend requirements (as defined in the Debt Rescheduling Agreement) would be greater than 1.1 to 1 through 1986; 1.35 to 1 in 1987; 1.75 to 1 in 1988 and 2 to 1 in 1989 and thereafter. At December 31, 1984, the Company would not have been permitted to incur additional non-subordinated debt under this formula.

Consolidated Statements of Cash Flows

Since mid-1982 the Company has followed a policy of strict cash conservation in response to a serious liquidity problem. The Company's sources of cash have been limited mainly to cash provided by continuing operations and changes in certain working capital items, including the utilization of operating lines and the deferral of taxes payable. Although significant amounts of cash have been generated through various asset dispositions, almost all of this cash was used to reduce associated debt and was not available to the Company for general use.

The following discussion of the Company's liquidity refers to its Consolidated Statements of Cash Flows, which identify significant items affecting the Company's financial position over the three years ended December 31, 1984.

Operating Activities

Cash generated from operations was $208.9 million in 1984, an improvement over both 1983 ($198.4 million) and 1982 ($103.6 million). The improvement in 1984 over 1983 was due to higher operating income, higher other corporate revenue and lower general and administrative expenditures, which more than offset increased interest and financing expenditures. Both interest and general and administrative expenditures are before deduction of amounts capitalized.

Although the prices received for the Company's crude oil, natural gas and NGL sales are regulated, such prices may be affected by changes in price levels in world oil markets. Prices in world oil markets have evidenced weakness in recent months, as reflected by declines in spot market prices below official OPEC posted prices for various grades of crude oil. While the Company believes that such uncertainty in world oil markets will continue in the near term, future world oil price movements cannot be predicted with any certainty. A significant decline in oil, natural gas or NGL prices would, by themselves, have a negative impact on the Company's net income and cash flow. However, the net effect of any such decline in prices on the liquidity and capital resources of the Company cannot be predicted with any certainty because it would be dependent upon numerous other factors, including levels of interest rates, the impact of future government policies and the effect of such a decline on prices and volumes of sales.

Investment Activities

The Company's ability to fund expenditures on capital projects during the past three years has been restricted due to its financial condition; however, major farmout agreements with Dome Canada and Home Oil have allowed the Company to maintain an active exploration and development program. Capital expenditures by the Company were $129.1 million before capitalized interest and general and administrative expenses of $81.1 million in 1984, as compared with $287.2 million before capitalized items of $165.9 million in 1983 and significantly larger expenditures in 1982.

The Company's capital expenditures are limited under the Debt Rescheduling Agreement to funds available from operations, borrowings (excluding advances under the Operating Credit Agreement), dispositions and issuance of equity after meeting debt and preferred share obligations, including any prepayments required to maintain prescribed security coverage ratios. The 1985 opening balance under the capital expenditure test was $109.2 million. The Company's management believes that Dome Petroleum must raise significant amounts of equity in order to provide funds for a prudent capital expenditure program. Significant capital expenditures, although lower than those made in the years prior to 1984, are required to develop the Company's asset base, maintain oil and gas reserves near current levels and generate sufficient cash flow to meet the debt repayment schedule set forth in the Debt Rescheduling Agreement. Year-to-year variations in the Company's level of capital expenditures may result from compliance with the financial covenants in the Debt Rescheduling Agreement. While such variations would not have a lasting impact on Dome Petroleum's ability to service and repay its debt, provide for its financial recovery and develop its assets, any prolonged failure to meet desired capital expenditure levels would adversely affect the Company's ability to do so.

In 1985, Dome Petroleum has budgeted capital expenditures of $160 million (excluding $53 million of capitalized interest and general and administrative expense), the bulk of which will be allocated to crude oil and natural gas development. In addition to its capital expenditure program the Company intends to continue its policy of farming out exploratory and, to a lesser extent, development drilling prospects to Dome Canada, Home and others.

Financing Activities

In 1984, the Company commenced scheduled repayments of long term debt, which repayments amounted to $186.1 million in 1984. The balance of 1984 repayments were made from disposition proceeds. During 1982 and 1983, long term debt repayments were comprised mainly of proceeds on disposal of assets which were applied to associated debt. The large increase in long term debt in 1982 and corresponding large long term debt repayment relate to the acquisition of HBOG and disposition of a portion of HBOG to others.

The Company is continuing to carry out a program of selected dispositions of non-core assets, which has included the following completed transactions: in 1982, the Company sold virtually all of its exploration and production interests located outside of North America for $328 million; in 1983, the Company sold all of its TransCanada shares for net proceeds of $263 million and substantially all of its producing and exploratory lands in the United States to Texaco Inc. for $242 million, of which U.S. $52 million was paid in Texaco common stock (the Company has sold for cash 50% of this stock); in 1984, the Company sold its 22.9% interest in Sovereign Oil & Gas PLC for $40 million, its 28.9% interest in Les Mines Selbaie for $16.6 million, and oil and gas properties in the Suffield area of Alberta for $19.3 million. Most of the cash proceeds of these dispositions have been used to reduce outstanding indebtedness. In March, 1985, the Company sold all of its shares of Davie for nominal consideration. Under the Debt Rescheduling Agreement the Company is required to sell assets for aggregate cash proceeds of at least $150 million prior to December 31, 1986. In a separate undertaking with certain of its lenders, the Company has agreed to sell 10 million of its 31 million shares of Dome Mines prior to December 31, 1986, which would be included in the $150 million asset sale commitment.

Under the Debt Rescheduling Agreement the Company is required to sell common shares of the Company, or other securities acceptable to the required lenders, for aggregate cash proceeds of at least $100 million prior to December 31, 1986.

The Company's management of its working capital position over the past three years has been mainly influenced by financing considerations and the effect of a reduced capital expenditure progam. The changes in the Company's working capital and a further breakdown of certain items contained in the consolidated statements of cash flows are set forth in Note 15 to the consolidated financial statements.

Report of Independent Chartered Accountants

To the Shareholders of
Dome Petroleum Limited

We have examined the consolidated balance sheets of Dome Petroleum Limited as at December 31, 1984 and 1983 and the consolidated statements of operations, retained earnings (deficit) and cash flows for the three years ended December 31, 1984. Our examinations were made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the Company as at December 31, 1984 and 1983 and the results of its operations and the changes in its financial position for the three years ended December 31, 1984 in accordance with accounting principles generally accepted in Canada which, except for the changes in 1983, with which we concur, in the accounting policies as described in Note 2 to the consolidated financial statements, have been applied on a consistent basis.

Calgary, Canada
March 25, 1985

Clarkson Gordon
Chartered Accountants

Comment of Independent Chartered Accountants for United States readers on differences between Canadian and United States reporting standards.

The above opinion is expressed in accordance with standards of reporting generally accepted in Canada.

On April 12, 1984 we commented that under United States reporting standards our opinion on the 1983 and 1982 consolidated financial statements would have been qualified as being subject to the Company's ability to continue as a going concern dependent upon the successful rescheduling of substantially all of its debt repayments. As explained in Note 7, the Company reached agreement with certain of its lenders under which repayment of a substantial portion of its debt has been rescheduled over the period extending to 1995. As a result, the uncertainty underlying our previous comment has been removed, and therefore under United States reporting standards, our present opinion on these consolidated financial statements would not have been qualified.

Calgary, Canada
March 25, 1985

Clarkson Gordon
Chartered Accountants

Dome Petroleum Limited
Consolidated Statements of Operations
Three Years Ended December 31, 1984

(Millions of Canadian Dollars, Except Per Share Amounts and as Otherwise Noted)

	1984	1983	1982
REVENUE			
Crude oil and natural gas	**$1,088.3**	$ 946.4	$1,003.8
Natural gas liquids	**1,012.5**	1,135.4	1,044.3
Contract drilling	**335.7**	409.3	505.7
Other	**11.1**	103.5	296.0
	2,447.6	2,594.6	2,849.8
EXPENSE			
Operating expense			
Crude oil and natural gas	**268.4**	249.2	264.7
Natural gas liquids	**833.6**	894.9	804.7
Contract drilling	**171.3**	221.0	315.7
Other	**11.9**	119.0	324.8
Depletion	**218.4**	213.7	185.3
Depreciation and amortization	**163.7**	138.1	127.7
Write-down of assets	**—**	1,099.0	213.6
Loss (gain) on disposal of assets	**(39.8)**	65.0	154.6
General and administrative	**82.9**	110.7	98.7
Interest on long term debt	**710.8**	679.3	789.2
Less interest capitalized	**(51.7)**	(136.8)	(212.9)
Other interest and financing charges	**163.5**	71.0	67.2
Foreign exchange	**123.0**	26.6	22.6
Preferred share dividends of subsidiaries	**15.7**	34.1	163.5
Other corporate revenue	**(36.9)**	(14.9)	(67.1)
Gain on cancellation of preferred shares	**—**	—	(70.0)
	2,634.8	3,769.9	3,182.3
Loss before income taxes and equity earnings	**187.2**	1,175.3	332.5
INCOME TAXES			
Current	**(249.3)**	135.1	127.0
Deferred	**287.4**	(161.2)	(33.1)
	38.1	(26.1)	93.9
Loss before equity earnings	**225.3**	1,149.2	426.4
EQUITY IN EARNINGS OF ASSOCIATED COMPANIES	**28.5**	44.2	57.1
NET LOSS	**$ 196.8**	$1,105.0	$ 369.3
Per common share *Net loss*	***$ 0.84***	*$ 4.72*	*$ 1.71*
Average number of common shares outstanding (in millions)	**248.5**	236.8	223.8

The accompanying notes are an integral part of the consolidated financial statements.

Dome Petroleum Limited
Consolidated Balance Sheets
December 31, 1984 and 1983

(Millions of Canadian Dollars)

ASSETS

	1984	1983
CURRENT		
Cash and short term deposits		
Restricted	**$ 83.4**	$ 108.3
Unrestricted	**155.0**	72.0
Accounts receivable		
Dome Canada Limited	**48.3**	78.7
Other	**448.2**	524.5
Inventories		
Product	**161.3**	151.4
Materials and supplies	**62.2**	85.0
	958.4	1,019.9
INVESTMENTS		
Dome Mines Limited (quoted market value December 31, 1984 - $285.5; December 31, 1983 - $528.8)	**243.9**	235.4
Less Dome Petroleum's pro rata interest in its common shares held by Dome Mines	**(107.1)**	(111.2)
	136.8	124.2
Dome Canada Limited (quoted market value December 31, 1984 - $233.5; December 31, 1983 - $244.2)	**412.7**	413.0
Sovereign Oil & Gas PLC (quoted market value December 31, 1983 - $34.3)	**—**	13.4
	549.5	550.6
PROPERTY, PLANT AND EQUIPMENT	**6,094.8**	6,359.4
DEFERRED FOREIGN EXCHANGE	**140.8**	73.2
OTHER ASSETS	**172.2**	174.9
	$7,915.7	$8,178.0

The accompanying notes are an integral part of the consolidated financial statements.

LIABILITIES AND SHAREHOLDERS' DEFICIENCY

	1984	1983
CURRENT		
Short term bank loans	**$ 15.2**	$ 95.1
Accounts payable and accrued liabilities		
Dome Canada Limited	**—**	172.4
Other	**778.5**	769.4
Income and other taxes payable	**40.5**	487.4
Long term debt due within one year	**205.3**	2,236.5
	1,039.5	3,760.8
LONG TERM DEBT	**6,097.5**	3,750.8
DEFERRED REVENUE	**212.8**	209.8
DEFERRED INCOME TAXES	**668.1**	369.2
REDEEMABLE PREFERRED SHARES		
Issued by a subsidiary	**220.0**	220.0
Issued by the Company	**97.9**	97.9
CONTINGENCIES AND COMMITMENTS (Note 20)		
SHAREHOLDERS' DEFICIENCY		
Preferred shares	**108.9**	112.8
Common shares (issued and outstanding at December 31, 1984 — 278,564,775; December 31, 1983 — 267,889,303)	**243.0**	209.6
Common share warrants	**—**	47.2
Contributed surplus	**45.7**	7.5
Deficit	**(710.6)**	(496.4)
Dome Petroleum's pro rata interest in its common shares held by Dome Mines	**(107.1)**	(111.2)
	(420.1)	(230.5)
	$7,915.7	$8,178.0

The accompanying notes are an integral part of the consolidated financial statements.

On behalf of the Board:

Director

Director

Dome Petroleum Limited
Consolidated Statements of Retained Earnings (Deficit)
Three Years ended December 31, 1984
(Millions of Canadian Dollars)

	1984	1983	1982
RETAINED EARNINGS (DEFICIT), BEGINNING OF YEAR	**$ (496.4)**	$ 621.3	$1,039.6
Net loss	**(196.8)**	(1,105.0)	(369.3)
	(693.2)	(483.7)	670.3
Preferred share dividends			
Stock	**(1.4)**	(1.5)	(1.7)
Cash	**(10.3)**	(10.2)	(12.1)
Termination of share purchase plans and disposition of common shares held by an acquired company	**(1.6)**	(1.0)	(35.2)
Reduction in Dome Petroleum's pro rata interest in its common shares arising from Dome Mines' issue of common shares	**(4.1)**	—	—
RETAINED EARNINGS (DEFICIT), END OF YEAR	**$ (710.6)**	$ (496.4)	$ 621.3

The accompanying notes are an integral part of the consolidated financial statements.

Dome Petroleum Limited
Consolidated Statements of Cash Flows
Three Years ended December 31, 1984
(Millions of Canadian Dollars)

	1984	1983	1982
OPERATING ACTIVITIES			
Cash operating income	**$1,162.4**	$1,110.5	$1,139.9
Interest and financing	**(890.0)**	(784.4)	(1,019.9)
General and administrative	**(112.3)**	(139.8)	(152.5)
Other — net	**48.8**	12.1	136.1
Cash from operations	**208.9**	198.4	103.6
INVESTMENT ACTIVITIES			
Expenditures on property, plant and equipment	**(129.1)**	(287.2)	(595.6)
Minority interest acquired in Hudson's Bay Oil and Gas Company Limited	**—**	—	(450.4)
Other — net	**12.3**	75.5	(92.4)
Cash used for investment	**(116.8)**	(211.7)	(1,138.4)
FINANCING ACTIVITIES			
Long term debt			
Increase	**4.6**	81.7	1,998.5
Repayment	**(267.8)**	(577.7)	(1,896.0)
Proceeds on disposal of assets	**138.8**	563.1	413.9
Issue of common shares and warrants	**33.4**	47.3	73.3
Other — net	**136.9**	206.2	420.8
Cash from financing	**45.9**	320.6	1,010.5
INCREASE (DECREASE) IN CASH	**138.0**	307.3	(24.3)
CASH, BEGINNING OF YEAR	**85.2**	(222.1)	(197.8)
CASH, END OF YEAR	**$ 223.2**	$ 85.2	$ (222.1)

Cash comprises cash and short term deposits net of short term bank loans.
The accompanying notes are an integral part of the consolidated financial statements.

Dome Petroleum Limited
Notes to Consolidated Financial Statements

(Millions of Canadian Dollars, Except Per Share Amounts and as Otherwise Noted)

The Company successfully rescheduled a substantial portion of its long term debt and other obligations effective December 31, 1984 and the consolidated financial statements give effect to the Debt Rescheduling Agreement and related agreements.

1. Summary of Significant Accounting Policies

The consolidated financial statements of the Company are stated in Canadian dollars and have been prepared in accordance with accounting principles generally accepted in Canada (see Note 21 for differences between Canadian and United States generally accepted accounting principles). A summary of the Company's significant accounting policies is presented below to assist in the review of the consolidated financial statements and other information contained in this report.

Principles of Consolidation

The consolidated financial statements include the accounts of Dome Petroleum Limited and its subsidiary companies other than Cyprus Anvil Mining Corporation ("Cyprus") and Davie Shipbuilding Limited ("Davie") as described in Investments below. The excess of the consideration paid for the shares of subsidiaries over their net book values at dates of acquisition has been attributed to the related property, plant and equipment.

Foreign Currency Translation

The accounts of foreign operations are stated in Canadian dollars. Current assets, current liabilities and long term liabilities are translated at the rates of exchange prevailing at the balance sheet date. Long term assets are translated at the rates in effect on the dates the assets were acquired. Exchange gains or losses arising on translation of long term liabilities are deferred and amortized over the remaining term of the liabilities. Revenue and expense items are translated at monthly average rates during the year with the exception of depletion, depreciation and amortization, which are translated at the rates of exchange used for the related assets. The resulting gains and losses are included in income.

Inventories of Product, Materials and Supplies

Inventories of product are valued at the lower of average cost and net realizable value. Materials and supplies are valued at average cost.

Investments

The Company's investments in Dome Mines Limited ("Dome Mines") and Dome Canada Limited ("Dome Canada") are accounted for by the equity method. Under this method these investments are carried at cost plus the related equity in undistributed earnings less the amortization of the excess of the purchase price over the net book value at dates of acquisition.

As at December 31, 1983, Cyprus and Davie have not been consolidated since it is the Company's intention to dispose of these investments. As a result, the Company's interests in Cyprus and Davie are included with other assets at their estimated realizable value.

Property, Plant and Equipment

The Company follows the full cost method of accounting for oil and gas operations whereby all costs of exploring for and developing oil and gas and related reserves are capitalized in two cost centres, western Canada and frontier. Such costs include land acquisition, geological and geophysical, interest and other carrying charges of unproved properties, costs of drilling both productive and non-productive wells and related overhead.

The carrying value of the Company's oil and gas properties is limited to the amount determined by estimating the present value of future net revenues from proved properties together with the value of unproved properties at the lower of cost and net realizable value.

Gains or losses are not recognized upon disposition of oil and gas properties accounted for under the full cost method unless such a disposition would significantly alter the relationship between capitalized costs and proved reserves of oil and gas. Gains or losses are recognized upon disposition of other assets.

Maintenance and repair costs are charged against income. Significant improvements are capitalized and replaced assets, if any, are retired from the accounts.

Depletion, Depreciation and Amortization

Provisions for depreciation of production facilities and depletion of oil and gas properties are calculated as the proportion of net property and production facility costs that current production revenues are to current plus estimated future production revenues from proved reserves as determined by Company or independent engineers. Estimated future revenues are based on prices contained in the Energy Pricing and Taxation Agreements reached between the federal government and the producing provinces assuming the existing world oil reference price remains constant.

Significant acquisition costs of unproved properties are excluded from the depletion calculation and are added to the depletion base as actual exploration activities are carried out, but in any event over a term not exceeding five years. Frontier costs are also excluded from the depletion calculation until quantities of proved reserves can be ascertained through further exploration. Frontier costs are amortized to income on a straight-line basis over 15 years commencing January 1, 1984. The amortization charged to income during the year ended December 31, 1984 amounted to $15.3 million ($0.06 per common share) net of deferred income taxes of $6.9 million.

The natural gas liquids system, pipelines, drillships and other vessels and other assets are depreciated on the straight-line basis at rates designed to amortize the assets over their estimated useful lives.

Developed oil sands rights and mining and related facilities are depreciated on the unit-of-production method. Undeveloped oil sands rights are amortized to income on the straight-line basis over 20 years.

Deferred Revenue

Payments received for undelivered gas have been deferred and are recognized as revenue when deliveries are made or upon expiry of the period allowed for such deliveries.

Capitalized Interest
Interest is capitalized on all oil and gas properties undergoing exploration and development activities that are not subject to depletion or amortization and on costs incurred during the construction of major additions to property, plant and equipment. When exploration and development ceases or is completed or the facility commences operations, subsequent interest costs are charged to income. Commencing January 1, 1984, interest is no longer capitalized on frontier exploration costs in view of the Company's decision to amortize such costs.

Income Taxes
The Company follows the deferral method of tax allocation accounting under which the income tax provision is based on the consolidated results of operations reported in the accounts. Under this method, the Company makes full provision for income taxes deferred principally as a result of claiming capital cost allowance, interest and exploration and development costs in excess of depreciation, depletion and amortization provided in the accounts.

Reclassification
Certain comparative figures in the accompanying consolidated financial statements have been reclassified to conform to the consolidated financial statement presentation adopted for the year ended December 31, 1984.

2. Changes in Accounting Policies

(a) Frontier Exploration Costs

In 1983, following changes in senior management and the Board of Directors, the Company decided to concentrate its future capital expenditures on the development of assets in three strategic areas: western Canada oil and gas, natural gas liquids and contract drilling. As a result, the Company concluded that its investment in the frontier areas should be segregated from its western Canada oil and gas operations and that it was preferable to establish a separate cost centre. This conclusion was based on management's decision to minimize direct expenditures in the frontier areas and the degree of uncertainty with respect to future development. Under the accounting policy followed prior to December 31, 1983, these costs would have been included with other oil and gas property costs and amortized to income in accordance with the Company's depletion policy. The application of this change in prior years under the Company's previous business plan would have had no effect on the results of operations or recorded costs in those years. Under the previous policy, any write-down of costs related to the frontier would not have been charged directly to income but would have been included in costs subject to depletion (see Summary of Significant Accounting Policies — Depletion, Depreciation and Amortization). This change in 1983 resulted in an increase in the net loss for the year of $316.6 million ($1.34 per common share). See also Investments regarding a 1983 change in accounting policy by Dome Canada.

(b) Foreign Currency Translation

Effective December 31, 1983, the Company adopted the foreign currency translation policies recommended by the Canadian Institute of Chartered Accountants. The effect of this change was to translate long term liabilities repayable in foreign currencies at the rates of exchange prevailing at the balance sheet date. The resulting exchange gains and losses are deferred and commencing January 1, 1984, amortized over the term of the related liabilities. Previously, long term liabilities repayable in foreign currencies were translated at the rates in effect at the dates the liabilities were incurred and exchange gains and losses were included in income only as realized. There was no effect on the 1983 results of operations but for the year ended December 31, 1984, amortization of deferred foreign exchange resulted in an increase in the net loss of $18.7 million ($0.08 per common share).

3. Investments

(a) Dome Mines

At December 31, 1984, the Company owned 30,861,184 common shares of Dome Mines representing a 38.3% interest therein, and Dome Mines together with its subsidiaries owned 24.0% of the outstanding common shares of the Company, resulting in the Company having a pro rata interest of 9.0% in its own common shares. Accordingly, the investment in Dome Mines has been reduced and shareholders' deficiency has been increased by the allocated portion of the cost of the investment that relates to the pro rata interest in the Company's common shares. The unamortized excess of the purchase price over the net book value of Dome Mines at dates of acquisition, other than its holdings in the Company, of $45.3 million is attributable to the value of the mineral assets held by Dome Mines and is being amortized over the expected life of these mineral assets.

During 1984 Dome Mines issued 3,000,000 units, each unit consisting of one common share and one gold purchase warrant, which resulted in the Company's interest in Dome Mines being reduced to 38.3% and its pro rata interest in its own common shares to 9.0%. The issue of these common shares to the public at a price greater than the Company's corresponding net book value resulted in an increase in the investment in Dome Mines of $6.1 million, a reduction in the Company's pro rata interest in its own common shares of $4.1 million and a credit to income and a charge to deficit of $10.2 million and $4.1 million respectively.

Details of the Company's investment in Dome Mines are as follows:

Years Ended	Number of Shares Owned[1]	Shares Acquired (Sold)		Dividends Received	Interest in Dome Mines[1]	Dome Mines' Interest in the Company[1]	Pro Rata Interest[1]
		Number	Amount				
1984	**30,861,184[2][3]**	**—**	**$—**	**$3.7**	**38.3%**	**24.0%**	**9.0%**
1983	30,861,184[2]	(216,000)	(4.7)	3.4	39.8	24.9	9.7
1982	31,077,184	561,400	6.4	3.5	40.1	25.9	10.2

(1) At end of years indicated.

(2) At year end, 28,452,198 shares were pledged under certain of the Company's loan agreements.

(3) The Company has an undertaking to sell, by December 31, 1986, 10 million common shares of Dome Mines.

Dome Mines
Summarized Financial Information
Balance Sheets

	December 31, 1984	1983
Current assets	$ 91.7	$ 80.9
Investments — Dome Petroleum	(90.7)	(56.0)
— Other	13.6	12.7
Property, plant and equipment	394.3	376.4
	$ 408.9	$414.0
Current liabilities	$ 36.5	$ 47.3
Long term debt	—	29.0
Deferred income and mining taxes	127.8	115.0
Minority interest in subsidiary companies	84.4	82.5
Deferred revenue	0.7	—
Shareholders' equity	159.5	140.2
	$ 408.9	$414.0

	Years Ended December 31, 1984	1983	1982
Statements of Operations			
Revenue	$ 215.1	$ 234.8	$ 182.6
Operating income	$ 64.9	$ 122.6	$ 88.6
Income before taxes and other items	$ 80.7	$ 173.4	$ 105.0
Income and mining taxes	(44.5)	(78.7)	(50.4)
Income after taxes, before other items	36.2	94.7	54.6
Income (losses) related to associated companies:			
Share of losses of:			
Canada Tungsten Mining Corporation Limited	(1.2)	(2.5)	(1.7)
Dome Petroleum	(55.7)	(290.9)	(110.4)
Gain on issue of shares by Dome Petroleum	6.7	—	—
Minority interest in net income of subsidiary companies	(11.7)	(17.8)	(17.1)
Loss	$ (25.7)	$(216.5)	$ (74.6)

(b) Dome Canada

At December 31, 1984, the Company owned 42,461,538 common shares of Dome Canada (48%) which were pledged under certain of the Company's loan agreements.

Dome Canada
Summarized Financial Information
Balance Sheet

	December 31, 1984	1983
Current assets:		
Due from Dome Petroleum Limited	$ —	$ 172.4
Other	322.6	311.1
Long term receivable — Dome Petroleum Limited	112.5	—
Property, plant and equipment	1,000.4	886.5
	$1,435.5	$1,370.0
Current liabilities:		
Due to Dome Petroleum Limited	$ 48.3	$ 78.7
Other	13.6	1.8
Deferred revenue	26.6	26.6
Long term debt	227.4	228.7
Deferred income taxes	144.3	91.3
Shareholders' equity	975.3	942.9
	$1,435.5	$1,370.0

Statement of Income

	Years Ended December 31,		
	1984	1983[1]	1982
Revenue	**$188.7**	$133.3	$116.0
Operating income	**$ 65.9**	$ 56.1	$ 47.7
Income before taxes and other items	**$ 99.8**	$ 79.2	$ 60.5
Taxes	**(67.4)**	(38.7)	(33.2)
Equity in earnings of TransCanada	**—**	—	24.5
Gain (loss) on sale of TransCanada shares net of deferred income taxes	**—**	17.7	(7.5)
Write-down of Frontier costs net of deferred income taxes	**—**	(51.1)	—
Net income	**$ 32.4**	$ 7.1	$ 44.3

[1] During 1983, Dome Canada changed its accounting policy with respect to Frontier costs. This change resulted in a reduction of net income of $51.1 million in 1983.

4. Property, Plant and Equipment

		December 31, 1984			December 31, 1983		
	Depletion, Depreciation and Amortization Rates	**Investment at Cost**	**Accumulated Depletion, Depreciation and Amortization**	**Net Investment**	Investment at Cost	Accumulated Depletion, Depreciation and Amortization	Net Investment
Oil and gas properties: Depleted	Unit of revenue[2]	**$4,445.3**	**$ 754.8**	**$3,690.5**	$4,123.5	$ 525.9	$3,597.6
Non-depleted[1]	—	**302.8**	**—**	**302.8**	519.4	—	519.4
Frontier[1]	6.7%	**332.6**	**22.2**	**310.4**	332.6	—	332.6
Oil sands:							
Mining and related facilities and developed rights	Unit of production[2]	**132.0**	**13.7**	**118.3**	125.6	10.2	115.4
Undeveloped rights	5.0%	**219.2**	**31.1**	**188.1**	219.2	20.1	199.1
Production facilities	Unit of revenue[2]	**685.6**	**116.2**	**569.4**	671.4	82.4	589.0
Natural gas liquids system and pipelines	3.3% to 6.7%	**581.6**	**169.8**	**411.8**	568.8	150.1	418.7
Drillships and other vessels	6.7% to 15.0%	**647.7**	**245.7**	**402.0**	640.9	193.1	447.8
Other	5.0% to 30.0%	**170.0**	**68.5**	**101.5**	274.8	135.0	139.8
		$7,516.8	**$1,422.0**	**$6,094.8**	$7,476.2	$1,116.8	$6,359.4

[1] Significant acquisition costs of unproved properties in western Canada are excluded from the depletion calculation and are added to the depletion base as actual exploration activities are carried out, but in any event over a term not exceeding five years. Unproved oil and gas properties will be transferred to the depletion base in equal annual instalments over the period to December 31, 1986.

Exploration and development costs incurred by the Company related to western Canada lands are included with costs to be depleted in the year of expenditure. Additional exploration costs on these lands and in the frontier incurred by farmout participants are not recorded in the accounts in accordance with industry practice.

Costs excluded from the depletion base are as follows:

	December 31, 1984			Years Ended December 31,			
	Western Canada	**Frontier**	**Total**	**1984**	1983	1982	1981 and Prior
Acquisition costs	**$709.2**	**$ 102.1**	**$ 811.3**	**$ —**	$ —	$ (72.1)	$ 883.4
Exploration costs	**—**	**408.2**	**408.2**	**—**	(1.2)	0.6	408.8
Capitalized interest	**464.1**	**275.7**	**739.8**	**51.2**	128.9	196.6	363.1
Transfers to depletion base	**(870.5)**	**—**	**(870.5)**	**(267.8)**	(239.4)	(225.8)	(137.5)
Write-down	**—**	**(453.4)**	**(453.4)**	**—**	(453.4)	—	—
Amortization	**—**	**(22.2)**	**(22.2)**	**(22.2)**	—	—	—
	$302.8	**$ 310.4**	**$ 613.2**	**$(238.8)**	$(565.1)	$(100.7)	$1,517.8

(2) Depletion, depreciation and amortization rates

	Years Ended December 31,		
	1984	1983	1982
Oil and gas properties and production facilities Per dollar based on production revenue	**$0.20**	$0.20	$0.14
Oil sands Per barrel of production	**4.33**	3.09	3.36

5. Restricted Cash, Short Term Bank Loans and Unused Lines of Credit

Restricted cash at December 31, 1984, in the amount of $83.0 million (December 31, 1983 — $93.4 million) was released in 1985. Of this amount, $35.2 million was applied to debt and $47.8 million was released to the Company for general corporate purposes. An additional $0.4 million (December 31, 1983 — $14.9 million) arising from the sale of the United States oil and gas properties is held in escrow.

Short term bank loans bear interest at various rates between the prime bank rate and the prime bank rate plus ½%. At December 31, 1984, $11.2 million (December 31, 1983 — $66.2 million) of these loans was secured by assignment of accounts receivable and $4.0 million (December 31, 1983 — $28.9 million) was unsecured.

The Debt Rescheduling Agreement which closed on February 5, 1985 provided the Company with access to funds under two additional credit facilities, the Operating Credit Agreement and the Secured Project Credit Agreement.

The Operating Credit Agreement provides up to $245.0 million in operating lines to be secured by accounts receivable of which $150.0 million will be made available up to February 6, 1986, irrespective of the level of pledged accounts receivable. The availability of credit under the Operating Credit Agreement is subject to review by the lenders at any time.

The Secured Project Credit Agreement makes available $200.0 million and U.S. $29.0 million secured by completed capital projects commenced after December 1, 1983. The acceptability of projects proposed by the Company as security will be reviewed by the lenders under guidelines contained in the Secured Project Credit Agreement prior to any lending under this facility.

6. Income Taxes

The income tax provisions differ from the calculated tax obtained by applying the combined Canadian federal-provincial corporate tax rate to the consolidated results of operations before income taxes. These differences are as follows:

	Years Ended December 31,		
	1984	1983	1982
Corporate tax rate	**47.1%**	47.1%	47.2%
Calculated income tax provision	**$ (88.1)**	$(553.5)	$(156.9)
Add (deduct) the tax effect of:			
Crown charges disallowed for tax purposes, less provincial rebates	**147.0**	114.8	122.5
Federal resource allowance	**(128.2)**	(99.1)	(106.9)
Earned depletion allowance	**(62.5)**	9.1	(44.7)
Investment tax credits	**(0.4)**	(7.6)	(7.5)
Non-deductible interest	**32.4**	22.9	14.4
Preferred share dividends of subsidiaries	**7.4**	16.0	77.2
Non-deductible depletion and depreciation	**55.8**	45.4	31.5
Reversal of depreciation for tax purposes which has no accounting equivalent	**—**	18.1	—
Petroleum and gas revenue tax	**60.8**	50.9	46.8
Gain on cancellation of preferred shares	**—**	—	(33.2)
Non-deductible foreign exchange	**44.4**	7.5	14.5
Capital loss on write-down of assets	**—**	268.2	100.8
Differences between the Canadian corporate rate and those rates applicable to foreign and mining operations	**(11.8)**	28.0	17.4
Capital loss (gain) on disposal of assets	**(16.8)**	40.0	23.6
Gain on deemed disposition of shares of Dome Mines	**(4.8)**	—	—
Reversal of tax provision on disposition of a subsidiary	**10.3**	—	—
Other	**(7.4)**	13.2	(5.6)
Income tax provision	**$ 38.1**	$ (26.1)	$ 93.9

Concurrently with the closing of the Debt Rescheduling Agreement, the Government of Canada and the Province of Alberta granted remission orders to the Company in respect of Hudson's Bay Oil and Gas Company Limited ("HBOG") income taxes. The remission orders allow the deduction of certain interest costs incurred by Dome Energy Limited ("Dome Energy") associated with Dome Energy's acquisition of HBOG from the taxable income of HBOG thereby eliminating HBOG's current income tax expense for 1982, 1983 and 1984. HBOG current income taxes accrued but unpaid for the 1982 and 1983 tax years in the amount of $256.5 million have therefore reduced current income tax expense in 1984 with a corresponding increase in deferred income tax expense.

The income tax provision is calculated on the basis of revenues and expenses recorded in the consolidated statements of operations. Deferred income taxes arise primarily from differences in the treatment of these items for financial statement purposes compared to the treatment for statutory income tax purposes. Deferred income taxes relating to these various timing differences are as follows:

	Years Ended December 31,		
	1984	1983	1982
Depreciation, depletion and amortization	**$ (5.5)**	$(106.2)	$ (5.3)
Interest — capitalized	**24.4**	55.5	58.7
— other[1]	**238.8**	(120.2)	(81.6)
Other capitalized expenses	**13.8**	1.4	13.1
Operating loss carryforwards	**3.0**	(7.5)	(21.0)
Other	**12.9**	15.8	3.0
	$287.4	$(161.2)	$(33.1)

[1] 1984 includes the effect of the remission orders described above.

The domestic and foreign components of loss (income) before income taxes together with related income taxes are set out below:

	Years Ended December 31,								
	1984			1983			1982		
	Canada	**Foreign**	**Total**	Canada	Foreign	Total	Canada	Foreign	Total
Loss (income) before income taxes and equity earnings	**$ 216.3**	**$(29.1)**	**$ 187.2**	$ 968.8	$206.5	$1,175.3	$ 81.9	$250.6	$332.5
Income taxes:									
Current	**$(251.3)**	**$ 2.0**	**$(249.3)**	$ 133.1	$ 2.0	$ 135.1	$115.0	$ 12.0	$127.0
Deferred	**287.4**	**—**	**$ 287.4**	(161.2)	—	(161.2)	45.0	(78.1)	(33.1)
	$ 36.1	**$ 2.0**	**$ 38.1**	$ (28.1)	$ 2.0	$ (26.1)	$160.0	$ (66.1)	$ 93.9

At December 31, 1984, the Company had the following tax loss carryforwards, investment tax credits and capital losses for which the tax benefits have not been recorded, as their recovery is not virtually certain:

	Canadian		U.S.	
Expiring in	Capital Losses	Investment Tax Credits	Tax Loss Carryforwards	Investment Tax Credits
1985	$ —	$19.1	$ —	$ —
1986	—	32.4	—	—
1987	—	3.2	—	—
1990 and thereafter	768.7	—	148.4	10.4
	$768.7	$54.7	$148.4	$10.4

7. Long Term Debt

Long term debt summarized below gives effect as at December 31, 1984 to the Debt Rescheduling Agreement and related agreements:

	Currency of Repayment	Repayment Date	December 31, 1984	1983
Bonds and Debentures				
Secured				
Income Debenture with interest at 52% of the prime bank rate plus 7/8%	Cdn.	1989 to 1995	**$ 200.0**	$ 200.0
10½% Series A Debentures	U.S.	1985 to 1993	**164.9**	169.6
14¾% Sinking Fund Debentures	U.S.	1992 to 2006	**129.1**	121.4
7.85% Collateral Trust Bonds net of funds on deposit of U.S. $2.2 million (1983 — U.S. $18.6 million)	U.S.	1994	**—**	—
Unsecured				
10⅜% Sinking Fund Debentures	Cdn.	1985 to 1996	**24.0**	25.5
10% Sinking Fund Debentures	U.S.	1985 to 1994	**61.9**	61.6
13½% Purchase Fund Debentures	U.S.	1985 to 1992	**51.8**	51.3
5¾% Purchase Fund Bonds	SF	1986 to 1991	**50.8**	57.9
7¼% Purchase Fund Bonds	SF	1985 to 1990	**50.8**	57.9

Term Bank Loans and Promissory Notes

Secured				
6%	Cdn.	1985 to 1998	**65.1**	69.8
Up to 16%	Cdn.	By 2030	**175.0**	175.0
Prime plus 5%, payable to Dome Canada	Cdn.	1986 to 1990	**112.5**	—
Prime plus 3/8% to prime plus 1 3/8%	Cdn.	1985 to 1995	**2,476.1**	2,428.4
U.S. prime plus 1/8%	U.S.	1987 to 1995	**62.0**	96.1
LIBOR plus 3/4%	U.S.	1985 to 1995	**1,420.5**	1,443.2
Unsecured				
15%	Cdn.	1984	**—**	0.9
16 1/4%	U.S.	1989	**4.1**	3.9
6%	SF	1986	**50.8**	57.9
10.84%	DM	1985 to 1991	**10.2**	12.3
Prime less 1/8% to prime plus 1 1/8%	Cdn.	1987 to 1995	**214.0**	189.1
LIBOR plus 1/4%	U.S.	1988	**99.1**	93.3
LIBOR plus 1/4%	U.S.	1989	**66.1**	62.2
LIBOR plus 5/8% to LIBOR plus 3/4%	U.S.	1987 to 1995	**562.9**	530.1
U.S. prime	U.S.	1985	**1.9**	4.0
Other				
Revenue Canada — Taxation (PGRT)	Cdn.	1986 to 1990	**204.1**	—
Leases and other —	Cdn.	Various	**38.2**	47.4
—	U.S.	Various	**6.9**	28.5
			6,302.8	5,987.3
Less amounts due within one year			**205.3**	2,236.5
			$6,097.5	$3,750.8

Approximate instalments (including sinking fund requirements) in each of the years 1985 to 1989 are (in millions): 1985 — $205.3; 1986 — $356.6; 1987 — $393.2; 1988 — $406.6 and 1989 — $401.7.

Principal balances in currencies other than Canadian dollars ("Cdn.") are translated on the basis that Cdn. $1.00 equals:

	December 31,	
	1984	1983
United States dollars ("U.S.")	**0.76**	0.80
Swiss francs ("SF")	**1.97**	1.73
Deutschemarks ("DM")	**2.39**	2.20

Certain of the term bank loans have multi-currency options whereby the Company may choose to convert the loans from one currency to another, including Canadian dollars, U.S. dollars, Swiss francs and other Euro-currencies. The total amount of such multi-currency loans as at December 31, 1984, was $632.4 million (1983 — $1,507.5 million).

In 1982, three other companies, including Maligne Resources Limited ("Maligne"), acquired an interest in HBOG. As a result, a secured term bank loan of Dome Energy, which at December 31, 1984 amounted to $187.1 million (1983 — $217.7 million), was offset by an account receivable of an equal amount. The bank's recourse on the loan to Dome Energy was limited to realization of its security, which consisted of interests in certain oil and gas and other assets acquired by Maligne. In 1985, Maligne assumed the term bank loan in return for cancellation of the account receivable.

Security

Essentially all the assets of the Company are either pledged as security for existing indebtedness or are the subject of covenants in financial instruments whereby the Company's ability to give security on such assets is restricted.

Bonds and debentures are secured by a charge on the Company's interest in the natural gas liquids system together with an assignment of related supply and sales contracts, certain oil and gas properties and related assets and cash deposits totalling U.S.$2.8 million (1983 — U.S.$19.1 million).

Term bank loans and promissory notes are secured by fixed and floating charges on certain oil and gas properties and related assets, fixed and floating charges on certain natural gas liquids system pipelines and related assets including transportation contracts, pledges of shares of Dome Mines, Dome Canada and certain subsidiaries including Cyprus, a $225.0 million guarantee by Dome Mines, certain other assets and cash deposits totalling $3.7 million and U.S. $0.1 million (1983 — $1.5 million and U.S. $14.1 million).

The promissory notes with cost of borrowing of up to 16% are held by Arctic Petroleum Corporation of Japan. The notes are secured by a floating charge on the oil and gas interests of the Company and Dome Canada in the Beaufort Sea region. The Company arranged that Arctic Petroleum Corporation of Japan advance $400.0 million in 1981 and 1982 to be used in conducting exploration activities in the Beaufort Sea. The first $175.0 million was assigned to the Company and the remaining $225.0 million has been retained by Dome Canada. The Company and Dome Canada are jointly and severally liable for repayment of the principal balance by the year 2030. Prior to that date, repayment of the principal amount is to be made from 20% of the net proceeds of production from certain fields to be developed in the Beaufort Sea. The cost of borrowing will be based on production from the Beaufort Sea and will not exceed 16% per year compounded annually from the date funds were advanced. Any payment in excess of the principal amount is contingent upon proceeds of production from the Beaufort Sea, which amounts cannot be determined. Accordingly, no provision will be made for such cost of borrowing until production commences.

Debt Rescheduling Agreement

A severe cash flow shortfall during 1982 caused the Company to approach its principal Canadian bankers and the Government of Canada for assistance. As a result, in September, 1982, an Agreement in Principle for restructuring the Company's debt and increasing its capitalization was reached with its principal Canadian bankers, the Government of Canada and Dome Mines. The Company continued to pursue alternative methods of improving its financial position and on December 1, 1983, presented to its lenders a plan (the "Plan") which primarily contemplated a rescheduling of its debt. During the period following the presentation of the Plan the Company continued negotiations with certain of its lenders. In August, 1984 the Company signed an agreement (as amended, the "Debt Rescheduling Agreement") under which approximately $5.3 billion of the Company's debt was rescheduled over a 12 year period extending to 1995. The Company's remaining long term debt of $1.1 billion will continue to be repaid on its original schedule.

Concurrently with the closing of the Debt Rescheduling Agreement on February 5, 1985, the Company reached agreement with Revenue Canada — Taxation to pay its 1982 and 1983 Petroleum and Gas Revenue Tax ("PGRT") liability over the five year period commencing January 2, 1986, with interest determined at the rate prescribed by the Income Tax Act (Canada), with Dome Canada to reschedule certain current obligations over the five year period commencing January 2, 1986 and with the Governments of Canada and Alberta who provided remission orders with respect to HBOG income taxes. The Agreement in Principle expired on October 1, 1984.

The Debt Rescheduling Agreement contains certain provisions including the following:

(a) New uniform covenants for the benefit of all participating lenders, which are in addition to existing covenants, requiring, among other things: the Company's working capital ratio may not fall below 0.7 to 1 as at the end of any two consecutive quarterly periods from February 5, 1985 until March 31, 1988 and 0.8 to 1 after December 31, 1987; the Company is required to maintain a consolidated capital base (generally, the total of the Company's shareholders' equity and subordinated debt, if any, excluding certain unrealized foreign exchange losses charged to income from December 31, 1983 to February 5, 1985, and including preferred shares net of any retractions or mandatory redemptions prior to 1996 and at December 31, 1985, but not thereafter, the amount of the Series D Cumulative Preferred Shares) of not less than negative $395.0 million at December 31, 1985, negative $315.0 million at December 31, 1986, negative $215.0 million at December 31, 1987 and negative $25.0 million at December 31, 1988 and thereafter in excess of $100.0 million and equal to or greater than (i) for 1989, 90% of the Company's consolidated capital base as at December 31, 1988, and (ii) thereafter, 90% of the average of the consolidated capital base as at the end of each of the two immediately preceding fiscal year ends; the Company's debt to equity ratio, the ratio of the Company's consolidated long term debt (generally, the total of long term debt excluding the current portion thereof, any retractions or mandatory redemptions of preferred shares prior to 1996, and the amount of deferred revenue in excess of $210.0 million) to its consolidated capital base is not to exceed 17 to 1 at December 31, 1989, 10 to 1 at December 31, 1990, 5 to 1 at December 31, 1991, and 4 to 1 at December 31, 1992, and as at the end of each fiscal year after December 31, 1988 is not to exceed 90% of the debt to equity ratio as at the end of the immediately preceding fiscal year, but the Company will not be required to achieve or maintain a debt to equity ratio of less than 3 to 1. Additional covenants restrict the level of capital expenditures and investments and limit, among other things, the Company's ability to grant new security, give guarantees, prepay debt, incur new debt or enter into capital and financial leases. In addition, the Company is prohibited from paying cash dividends on its common shares until 1989. Thereafter such dividends are limited to 50% of annual earnings, provided that the cumulative amount of such dividends is not more than 50% of the amount by which retained earnings exceed $1.0 billion;

(b) The Company's existing credit facilities, which were amended in part but not superseded by the Debt Rescheduling Agreement, contain additional covenants and events of default which will remain in force. The Debt Rescheduling Agreement also provides for new uniform events of default which are in addition to those currently in the Company's existing loan documents. While the Company received waivers of all events which constituted or may have constituted events of default under its rescheduled credit facilities known to its lenders effective as of the date of closing of the Debt Rescheduling Agreement, any future acceleration of debt under any credit facility, including those amended by the Debt Rescheduling Agreement, (which includes certain outstanding debt of Cyprus of $146.4 million due in annual instalments commencing after 1986 as follows (in millions): 1987 — $3.9; 1988 — $1.8; and 1989 — $3.0) would constitute an event of default under the Debt Rescheduling Agreement itself, in addition to bringing into operation cross default clauses in the underlying credit facilities. Upon any failure to maintain compliance with the covenants contained in the Debt Rescheduling Agreement or the underlying credit facilities, the Company could seek a waiver or amendment of the covenants involved. A waiver or amendment of the covenants in the Debt Rescheduling Agreement described above would require the consent of (i) a majority of the Company's four principal Canadian bank lenders, (ii) members of a syndicate of the Company's principal U.S. bank lenders holding 66⅔% of the debt held by this syndicate, and (iii) lenders holding 66⅔% of the remaining debt subject to the Debt Rescheduling Agreement;

(c) Promissory notes issued to two Canadian subsidiaries of foreign lenders in the amount of $74.9 million which were included in short term bank loans were rescheduled;

(d) A requirement to sell common shares of the Company, or other securities as approved by the lenders, for aggregate cash proceeds of at least $100.0 million prior to December 31, 1986;

(e) A requirement to sell assets for aggregate cash proceeds of at least $150.0 million prior to December 31, 1986, which may be satisfied in whole or in part by compliance with the Company's undertaking to sell 10 million common shares of Dome Mines;

(f) Additional interest is payable on all rescheduled debt principal at the rate of ⅛% per annum commencing in April, 1984, and increasing by an additional ⅛% per annum in April of each of 1987, 1990 and 1993;

(g) The Company may be required to make prepayments if production from oil and gas reserves securing certain rescheduled credit facilities occurs at a rate faster than that forecast by formulas contained in these rescheduled credit facilities, and may also become obligated, commencing at any time on or after December 31, 1986, to grant additional security or to make prepayments under certain rescheduled credit facilities should the value of security for these facilities not meet a fixed ratio to outstanding indebtedness after that date. Proceeds from the sale of assets, rights or properties which secure any rescheduled facility must be used to prepay that facility.

The Debt Rescheduling Agreement is effective December 31, 1984 and therefore in the consolidated balance sheet $74.9 million of short term bank loans, $204.1 million of PGRT (together with related interest) included in income and other taxes payable, $112.5 million of accounts payable owing to Dome Canada and $2,324.2 million of long term debt due within one year have been reclassified to long term debt. The consolidated statement of operations for 1984 reflects the ⅛% increase in interest rates on rescheduled debt commencing April, 1984 and the effect of the remission orders from the federal and provincial Governments on current and deferred income taxes.

In addition, the Company paid $31.8 million to the lenders as consideration for rescheduling the debt. This amount was charged to operations in 1984 and comprised $4.7 million in cash and 12,223,757 common shares of the Company, having a value of $27.1 million, which were issued in 1985 in connection with the closing of the Debt Rescheduling Agreement.

8. Redeemable Preferred Shares Issued by Subsidiaries

Redeemable preferred shares issued by subsidiaries and outstanding for the three years ended December 31:

		1984		1983		1982	
	Authorized	**Outstanding**	**Amount**	Outstanding	Amount	Outstanding	Amount
Provo Gas Producers Limited Series A	**2,200,000**	**2,200,000**	**$220.0**	2,200,000	$220.0	2,200,000	$ 220.0
Dome Resources Limited Class A Preferred Shares	**Unlimited**		—		—	12,719,149	731.4
Less unamortized discount on issue			—		—		(2.8)
							728.6
Escrow funds			—		—		(749.8)
			—		—		(21.2)
Reclassified to accounts payable			—		—		21.2
			—		—		—
Davie Shipbuilding Limited Class A	**50,000**		—		—	50,000	5.0
			$220.0		$220.0		$225.0

The 2,200,000 Series A cumulative, non-voting, first preference shares are redeemable at the holder's option in 1988. The dividend rate is 52% of the prime bank rate plus ¾%. A subsidiary has agreed to redeem the preferred shares upon the occurrence of certain events of default. If the subsidiary fails to redeem the preferred shares when required, the Company can be required to purchase the preferred shares, and a Canadian bank has agreed to provide an unsecured term bank loan for that purpose. The subsidiary has agreed to redeem 97,400 shares over two years commencing in 1987 and, together with the Company, has given the Canadian bank a joint and several promissory note evidencing their obligation to satisfy the remaining redemption obligation in 1989 by way of an unsecured term bank loan, repayable quarterly from 1989 to 1995. The interest rate will be prime plus 1½%, increasing by an additional ⅛% per annum in April of each of 1990 and 1993.

The $5.75 Class A Retractable Preferred Shares ("Class A Preferred Shares") were issued by Dome Resources Limited ("Dome Resources") in 1982 in exchange for the outstanding common shares of HBOG held by minority interest shareholders. The Class A Preferred Shares were recorded at a discount which was amortized over the period to date of redemption. During 1982 the Company purchased for cash, 23,201,531 Class A Preferred Shares which were surrendered to Dome Resources for cancellation. The remaining shares were redeemed for cash in 1983.

The escrow funds held by a trustee were sufficient at all times to retract the outstanding Class A Preferred Shares. These funds were invested with interest earned being paid into a cash collateral account which formed part of the security for a related term bank loan. In the consolidated financial statements, interest earned on the escrow funds reduced interest expense on the related term bank loan in the amount of $17.2 million in 1983 (1982 — $178.3 million).

The 50,000 Class A 5% cumulative preferred shares issued by a subsidiary were purchased by the Company at a par value of $100 per share in 1983.

9. Preferred Shares

Authorized: An unlimited number of preferred shares and subordinated preferred shares issuable in series.

Preferred shares outstanding for the three years ended December 31:

		1984		1983		1982	
	Authorized	**Outstanding**	**Amount**	Outstanding	Amount	Outstanding	Amount
Redeemable at the option of the Company: 7.76% Series A and B	**10,500,000**	**4,705,572**	**$112.8**	4,847,649	$117.2	4,875,578	$119.9
Stock dividends		**107,949**	**1.4**	107,223	1.5	152,420	1.7
Purchased		**(220,200)**	**(5.3)**	(249,300)	(5.9)	(180,349)	(4.4)
		4,593,321	**$108.9**	4,705,572	$112.8	4,847,649	$117.2
Redeemable at the option of the holder: 8.725% Series C	**1,450,000**	**1,450,000**	**$ 36.2**	1,450,000	$ 36.2	1,450,000	$ 36.2
7.25% Series D	**4,110,517**	**4,110,517**	**61.7**	4,110,517	61.7	4,110,517	61.7
		5,560,517	**$ 97.9**	5,560,517	$ 97.9	5,560,517	$ 97.9

The Series A Cumulative Preferred Shares and Series B Cumulative Stock Dividend Preferred Shares were issued at $25 per share and are interconvertible at any time on a share for share basis at the option of the holder. The shares are redeemable at the option of the Company at $26 per share to August 31, 1985, declining thereafter by $0.20 per share annually to $25 after August 31, 1990. The Company is required to use all reasonable efforts to purchase in the market each year a number of Series A or Series B Preferred Shares equal to the sum of 50,000 shares per quarter and 1% of the number of Series B shares issued as stock dividends since August 31, 1979, less certain other adjustments, provided such shares are available at prices not exceeding $25 per share plus cost of purchase.

During 1984, the Company purchased for cancellation 220,200 (1983 — 249,300; 1982 — 180,349) Series A and B Preferred Shares at a discount of $2.5 million (1983 — $2.3 million; 1982 — $2.4 million) which has been credited to contributed surplus.

The Series C Cumulative Preferred Shares were issued at $25 per share with an annual requirement to redeem 5% of the issued shares beginning in 1985 at $25 per share. Each holder has the right to waive this redemption obligation of the Company in any year. The dividend rate of 8.725% per annum was fixed in 1984 and will be adjusted every five years thereafter. The Company has certain obligations to vary the dividend rate to indemnify the holders against any reduction in the after-tax return on their investment resulting from future changes in Canadian income tax legislation.

The Series D Cumulative Preferred Shares ("Series D Shares"), issued at $15 per share, have a stated dividend rate of 7.25% per annum and were redeemable in whole or in part at the option of the holder at $15 per share in 1984. In return for the waiver by the holder of the Series D Shares of certain restrictive covenants, the Company agreed to purchase the shares for $62.8 million in 1982 or such later date up to January 3, 1984 as designated by the holder. The holder of the Series D Shares gave notice requiring the Company to redeem the shares, but agreed not to present the shares to the Company for redemption prior to February 5, 1985. Pursuant to such arrangements, the holder of the Series D Shares received, in lieu of dividends, interest on an amount equal to the purchase price at a rate equal to the prime bank rate plus 2%. On February 5, 1985, the Company and the holder of the Series D Shares agreed that (i) the holder of the Series D Shares would continue to hold such shares and receive interest in lieu of dividends at the same rate as above, (ii) the holder would be entitled to exchange such shares for a series of subordinated convertible preferred shares at any time prior to January 1, 1987 at the option of the holder, (iii) the holder would be entitled to present the shares for redemption if the Company fails to meet certain conditions and (iv) the Company would be entitled to require the holder to exchange such shares for a series of subordinated convertible preferred shares at any time after the Company has complied with these conditions. In addition, if the holder of the Series D Shares continues to hold such shares after 1986 the holder may present the shares for payment of the redemption price over a ten year period commencing in 1987.

10. Common Shares

Authorized: An unlimited number of common shares of no par value.

Common shares issued (cancelled) during the three years ended December 31:

	1984		1983		1982	
	Shares	**Amount**	Shares	Amount	Shares	Amount
Employee Profit Sharing	**10,470,843**	**$ 32.4**	9,248,895	$ 42.2	9,550,000	$ 25.8
Employee Share Bonus Plan	**27,000**	**0.1**	517,757	2.8	108,568	0.3
Exercise of options	**326,757**	**0.9**	825,005	2.3	—	—
Share purchase plans	**(151,250)**	**—**	(105,875)	—	(2,325,000)	—
Exchange for shares of a subsidiary	**2,122**	**—**	6,375	—	802	—
Net increase in common shares outstanding	**10,675,472**	**33.4**	10,492,157	47.3	7,334,370	26.1
Common shares outstanding, beginning of year	**267,889,303**	**209.6**	257,397,146	162.3	250,062,776	136.2
Common shares outstanding, end of year[1]	**278,564,775**	**$243.0**	267,889,303	$209.6	257,397,146	$162.3

[1] For the calculation of net loss per common share, the weighted average number of common shares outstanding less the Company's pro rata interest in its outstanding common shares held by Dome Mines is used.

At December 31, 1984, 19,761,707 shares were reserved for issue as follows: 13,903,882 under the Company's employee share and incentive plans, 5,750,000 for other options and 107,825 for shares of a subsidiary not yet presented for exchange.

(a) Employee Share and Incentive Plans

In 1982, the shareholders approved a By-Law, as amended in 1984, under which the directors were authorized to provide various incentives and awards to employees of the Company. The more important features of this By-Law are as follows:

(i) 35,000,000 common shares were reserved for issue to the Employee Profit Sharing Plan at prevailing market prices, of which 29,269,738 shares have been issued to December 31, 1984; and

(ii) 10,000,000 common shares were reserved for Employee Share Bonus Plans and stock options, of which 1,805,087 shares have been issued to December 31, 1984, 21,293 are no longer reserved as a result of the exercise of stock appreciation rights and an additional 7,116,570 shares have been allocated to meet stock options granted to officers and other key employees. In 1984, the By-Law was amended to provide a stock appreciation right which permits employees to surrender exercisable stock options and receive common shares equal in aggregate market value to the difference between the current market price per share and the option price per share multiplied by the number of surrendered options.

Details of stock options granted and exercised under the By-Law are as follows:

Shares Under Option	Number of Common Shares	Option Price Per Share[3]	Option Price Total[4]	Market Price Per Share[3]	Market Price Total[4]	
Granted during 1982: Officers[1]	1,363,000	*$3.50*	$ 4.8	*$3.50*	$ 4.8	(A)
Other key employees	6,319,175	*2.75*	17.4	*2.75*	17.4	(A)
December 31, 1982	7,682,175		22.2			
Granted during 1983: Officers[2]	388,500	*3.90*	1.5	*3.90*	1.5	(A)
Other key employees	163,950	*5.16*	0.8	*5.16*	0.8	(A)
Exercised during 1983: Officers	(29,000)	*3.50*	(0.1)	*5.68*	0.2	(B)
Other key employees	(796,005)	*2.75*	(2.2)	*5.62*	4.5	(B)
December 31, 1983	7,409,620		22.2			
Granted during 1984: Other key employees	**55,000**	***3.04***	**0.2**	***3.04***	**0.2**	**(A)**
Exercised during 1984: Other key employees	**(348,050)**	***2.75***	**(1.0)**	***3.74***	**1.3**	**(B)**
Options not yet exercised	**7,116,570**		**$21.4**			

(A) At date options were granted

(B) At date options were exercised

(1) Including two officers who were also directors.

(2) Including three officers, two of whom were then directors, one of whom has since become a director.

(3) Weighted average price.

(4) In millions of Canadian dollars.

Of the options granted and not yet exercised at December 31, 1984, 6,835,870 were then exercisable and the remaining 280,700 were exercisable on varying dates to 1993.

(b) Other Options

Independent of the employee share and incentive plans, an option to purchase 3,000,000 common shares at a price of $5.875 per share was granted to Mr. J.H. Macdonald, Chairman and Chief Executive Officer of the Company, in 1983. The option is for a term of ten years exercisable from October 1, 1983. The Company has also agreed with him that if his incentive option should expire without, in effect, his having realized at least one million dollars therefrom, the difference will be paid to him or his estate in cash.

In 1983, the Company granted to Morgan Stanley & Co. Incorporated, an option to acquire 2,750,000 common shares of the Company at $5.60 per share until November 3, 1988, in partial consideration of financial advisory services performed.

(c) Share Purchase Plans

At December 31, 1984, 2,582,125 previously issued common shares have been surrendered and cancelled following the termination of certain share purchase plans. These capital transactions reduced other assets and increased the deficit by $1.6 million, $1.0 million and $23.9 million in each of the years 1984, 1983 and 1982 respectively.

The Company has made interest free loans to trustees to enable certain present and past officers to purchase shares from the Company under share purchase plans. At December 31, 1984, $5.6 million (1983 — $5.9 million) was receivable under the above arrangements and is included in other assets.

(d) Other

During 1982 retained earnings were charged with $11.3 million (net of deferred income taxes amounting to $10.9 million) as a result of the disposition of 1,369,500 common shares of the Company held by an acquired company.

11. Contributed Surplus

Changes in contributed surplus during the three years ended December 31:

	1984	1983	1982
Contributed surplus, beginning of year	**$ 7.5**	$5.2	$2.8
Gain on purchase and cancellation of Series A and Series B preferred shares	**2.5**	2.3	2.4
Gain on expiry of common share warrants, net of deferred income taxes of $11.5 million	**35.7**	—	—
Contributed surplus, end of year	**$45.7**	$7.5	$5.2

12. Write-Down of Assets

In 1983, the Company reviewed all of its assets with particular attention to assets not identified with strategic areas of operation and wrote down the carrying values of such assets in the amount of $1,099.0 million before deferred income taxes of $202.1 million. This write-down was comprised of the following items:

(a) $453.4 million, before deferred income taxes of $136.8 million, related to certain acquisition and exploration costs incurred in the frontier areas which were previously held to be recoverable. The Company no longer expects to fund exploration prospects on certain lands where dry holes or non-commercial gas discoveries have been drilled and as a result such costs were charged to income;

(b) $463.7 million, before deferred income taxes of $25.0 million, that represented a majority of the costs related to the Company's mining assets including Cyprus and various coal properties, and certain ancillary business interests including Davie. Such assets were not included in the Company's three strategic areas of operations and were written down to estimated realizable value in anticipation of their disposition;

(c) $84.0 million, before deferred income taxes of $40.3 million, related to costs of certain projects which were deferred or terminated and certain other costs related to the Company's refinancing activities; and

(d) $97.9 million in the carrying value of its United States oil and gas properties (including $11.0 million related to equipment inventory) following a detailed review of oil and gas reserves and exploratory acreage.

At December 31, 1982 the Company determined that, primarily due to declines in oil and gas prices and property values, a write-down of $213.6 million in the carrying value of its United States oil and gas properties was required. The Company sold its United States oil and gas properties in 1983.

13. Disposal of Assets

During 1984, the Company sold certain assets, including its 22.9% interest in Sovereign Oil & Gas PLC, for total proceeds of $138.8 million which resulted in a gain of $39.8 million before deferred income taxes of $9.8 million.

During 1983, the Company sold certain of its assets which were determined not to be of a strategic business nature. These assets included virtually all of its producing and exploratory lands in the United States, but did not include any portion of its interest in the Cochin Pipeline system. The proceeds on sale of the United States oil and gas assets (including $9.9 million of related inventory) amounted to $241.7 million. The Company also disposed of its interest in TransCanada PipeLines Limited ("TransCanada") for $263.1 million. Proceeds on total asset disposals were $563.1 million which resulted in a loss of $65.0 million before deferred income tax charges of $11.6 million.

During 1982 the Company sold certain of its assets including its oil and gas interests in Indonesia, Australia, Brazil, Egypt and the Netherlands. The total sales proceeds were $413.9 million which resulted in a loss of $154.6 million before deferred income taxes of $54.2 million.

14. Net Loss Per Common Share

Net loss per common share is calculated, after deduction of preferred share dividends, using the weighted average number of common shares outstanding, which amounts have been reduced by the Company's pro rata interest in its outstanding common shares held by Dome Mines.

	Years ended December 31,		
	1984	1983	1982
	(In Millions, Except Per Share Amounts)		
Weighted average number of common shares outstanding during the year	**273.5**	262.8	250.3
Less pro rata interest in outstanding shares held by Dome Mines	**(25.0)**	(26.0)	(26.5)
	248.5	236.8	223.8
Net loss per common share	***$ 0.84***	*$ 4.72*	*$ 1.71*

15. Consolidated Statements of Cash Flows

In 1984, the consolidated statements of cash flows have been prepared on the basis of changes in the Company's cash resources which are comprised of cash and short term deposits, net of short term bank loans. In prior years, the Company prepared its statements of changes in financial position on the basis of changes in working capital.

(a) Operating Activities

(i) Cash operating income is derived from the consolidated statements of operations as follows:

	Years ended December 31,		
	1984	1983	1982
Revenue	**$2,447.6**	$2,594.6	$2,849.8
Cash operating expense Crude oil and natural gas	**268.4**	249.2	264.7
Natural gas liquids	**833.6**	894.9	804.7
Contract drilling	**171.3**	221.0	315.7
Other	**11.9**	119.0	324.8
	1,285.2	1,484.1	1,709.9
Cash operating income	**$1,162.4**	$1,110.5	$1,139.9

(ii) Interest and financing (comprised of interest on long term debt, other interest and financing charges and preferred share dividends of subsidiaries) and general and administrative expense are before deduction of capitalized amounts of $81.1 million, $165.9 million and $266.7 million in 1984, 1983 and 1982 respectively.

(b) Investment Activities

Expenditures on property, plant and equipment are before the capitalized items referred to under operating activities above, as follows:

	Years ended December 31,		
	1984	1983	1982
Capital expenditures (as detailed in Business Segments in Note 18)	**$210.2**	$453.1	$862.3
Deduct: Capitalized interest	**(51.7)**	(136.8)	(212.9)
Capitalized general and administrative expense	**(29.4)**	(29.1)	(53.8)
	$129.1	$287.2	$595.6

(c) Changes in Working Capital

	Years ended December 31,		
	1984	1983	1982
(i) Changes in Cash:			
Cash and short term deposits			
Restricted	**$ (24.9)**	$ 108.3	$ —
Unrestricted	**83.0**	69.6	(30.9)
Short term bank loans	**79.9**	129.4	6.6
Increase (decrease) in cash	**$ 138.0**	$ 307.3	$ (24.3)
(ii) Changes in other working capital items:			
Accounts receivable			
Dome Canada	**$ 30.4**	$ 62.6	$ (65.7)
Other	**76.3**	165.2	22.6
Inventories			
Product	**(9.9)**	31.5	(4.1)
Material and supplies	**22.8**	108.4	29.7
Accounts payable and accrued liabilities			
Dome Canada	**(172.4)**	(13.6)	137.3
Other	**9.1**	(107.3)	104.5
Income and other taxes payable	**(446.9)**	220.5	240.9
Long term debt due within one year	**(2,031.2)**	8.0	2,077.8
	(2,521.8)	475.3	2,543.0
Add (deduct) reclassified liabilities:			
Long term debt due within one year	**2,031.2**	(8.0)	(2,077.8)
PGRT liabilities	**204.1**	—	—
Dome Canada promissory note	**112.5**	—	—
Short term bank loans	**74.9**	—	—
Deferral of HBOG current income taxes	**256.5**	(134.3)	(122.2)
Changes in other working capital items having a cash effect	**$ 157.4**	$ 333.0	$ 343.0

Changes in other working capital items having a cash effect relate to the following activities and are included in Other — net:

	Years ended December 31,		
	1984	1983	1982
Investment	**$ 10.3**	$ 137.9	$ (20.5)
Financing	**147.1**	195.1	363.5
	$ 157.4	$ 333.0	$ 343.0

16. Acquisitions

In 1982, the Company acquired all the outstanding shares of HBOG not already owned in exchange for securities valued at $2,065.4 million consisting of 35,920,680 Class A Preferred Shares of Dome Resources and 47,894,240 common share warrants of the Company valued for accounting purposes at $47.2 million. On the same date three other companies acquired a 34.1% aggregate interest in HBOG as follows: Dome Canada acquired an 11.1% interest for a consideration of $488.0 million in cash and marketable securities; Maligne acquired a 10.0% interest for a consideration of $451.0 million consisting of $192.0 million in cash, an account receivable of $19.0 million and a $240.0 million account receivable for the balance of the purchase price to be repaid over nine years with interest; and TCPL Resources Ltd., a wholly-owned subsidiary of TransCanada, acquired a 13.0% interest for a consideration of $560.0 million in cash.

The net acquisition costs of $670.3 million were allocated as follows (in millions):

Value attributed to net property, plant and equipment	$182.9
Assumption of deferred revenue	39.0
Minority interest acquired	450.4
Disposition of inventory	(2.0)
	$670.3

17. Related Party Transactions

(a) Dome Canada

The Company is party to certain agreements with Dome Canada which enable Dome Canada to earn interests in certain exploratory and development lands, excluding certain lands in western Canada which currently have productive capability and oil sands properties, in return for the obligation to fund exploration and development, including the drilling of exploratory wells and geological and geophysical surveys. Subsequent development costs will be borne by the Company and Dome Canada in proportion to their respective interests. The operations of Dome Canada, including the majority of its administration, are carried out by the Company on behalf of Dome Canada.

Dome Canada holds a secured promissory note of the Company in the amount of $112.5 million which bears interest at prime plus 5% and is repayable on January 2 in each of the following years (in millions): 1986 — $11.2; 1987 — $16.9; 1988 — $22.5; 1989 — $28.1; and 1990 — $33.8. During 1984 the Company paid interest to Dome Canada of $15.1 million (1983 — $12.0 million; 1982 — $12.2 million) in respect of this note.

With respect to the Dome Exploratory Lands Agreement and the Corporate Services Agreement, the Company charged Dome Canada during 1984 the following:

(i) $200.5 million (1983 — $296.7 million; 1982 — $446.6 million) with respect to capital expenditures for exploration, development and Beaufort Sea drilling services;

(ii) $5.1 million (1983 — $5.9 million; 1982 — $6.5 million), inclusive of out of pocket expenses, with respect to corporate services; and,

(iii) Dome Canada advanced to the Company on January 1, 1984, $52.6 million (1983 — $60.0 million), an amount equal to 1/8 of Dome Canada's budgeted annual capital expenditures. This amount was refunded to Dome Canada on December 31, 1984. Monthly cash advances are now made in accordance with industry practice.

(b) Dome Mines

During 1984, the Company paid to Dome Mines $10.8 million (1983 — $11.8 million; 1982 — $8.2 million) with respect to a $225.0 million guarantee of certain term bank loans.

(c) TransCanada

Revenue and cost of product arising from transactions with TransCanada and included in the consolidated statements of operations during 1982 amounted to $267.2 million and $30.5 million respectively.

18. Information by Business Segment and Geographic Area

The Board of Directors of the Company has determined that the principal business segments of the Company are:

Crude oil and natural gas — Exploration, development and production activities for crude oil and field liquids, natural gas, sulphur and oil sands.

Natural gas liquids — The extraction, purchase, transportation and marketing of natural gas liquids.

Contract drilling — Drilling and dredging contracting in the Beaufort Sea.

The information for 1983 and 1982 includes the consolidation of Davie and Cyprus for 12 months with respect to revenues, expenses, capital expenditures and depletion, depreciation and amortization.

BUSINESS SEGMENTS	1984	1983	1982
REVENUE			
Crude oil and natural gas	**$1,088.3**	$ 946.4	$ 1,003.8
Natural gas liquids	**1,012.5**	1,135.4	1,044.3
Contract drilling	**335.7**	409.3	505.7
Other operating	**11.1**	103.5	296.0
	$2,447.6	$ 2,594.6	$ 2,849.8
TRANSFERS BETWEEN BUSINESS SEGMENTS (not included above)			
Crude oil and natural gas	**$ 43.4**	$ 30.5	$ 49.5
Contract drilling	**0.4**	2.4	1.4
Eliminations	**(43.8)**	(32.9)	(50.9)
	$ —	$ —	$ —
OPERATING INCOME			
Crude oil and natural gas	**$ 532.4**	$ 437.2	$ 516.7
Natural gas liquids	**158.5**	219.8	214.2
Contract drilling	**112.2**	145.6	153.2
Other operating	**(22.8)**	(43.9)	(57.2)
	780.3	758.7	826.9
GAIN (LOSS) ON WRITE-DOWN AND DISPOSAL OF ASSETS			
Crude oil and natural gas	**0.4**	(667.2)	(355.3)
Natural gas liquids	**0.7**	—	—
Contract drilling	**2.3**	(12.0)	—
Other operating	**6.2**	(459.5)	(10.9)
	9.6	(1,138.7)	(366.2)
LOSS (INCOME) BEFORE CORPORATE REVENUE AND EXPENSE	**(789.9)**	380.0	(460.7)
CORPORATE (REVENUE) EXPENSE			
General and administrative expense — net	**82.9**	110.7	98.7
Interest and financing charges — net	**822.6**	613.5	643.5
Loss (gain) on disposal of investments and corporate assets	**(30.2)**	(21.3)	2.0
Write-down of corporate assets	**—**	46.6	—
Foreign exchange	**123.0**	26.6	22.6
Preferred share dividends of subsidiaries	**15.7**	34.1	163.5
Other corporate revenue	**(36.9)**	(14.9)	(67.1)
Gain on cancellation of preferred shares	**—**	—	(70.0)
Income taxes	**38.1**	(26.1)	93.9
Equity in earnings of associated companies	**(28.5)**	(44.2)	(57.1)
	986.7	725.0	830.0
NET LOSS	**$ 196.8**	$ 1,105.0	$ 369.3
IDENTIFIABLE ASSETS			
Crude oil and natural gas	**$5,534.5**	$ 5,671.8	$ 6,616.5
Natural gas liquids	**758.1**	818.0	914.2
Contract drilling	**447.7**	577.0	668.7
Other operating	**11.8**	99.3	704.4
	6,752.1	7,166.1	8,903.8
Deferred foreign exchange	**140.8**	73.2	—
Investments	**549.5**	550.6	784.6
Other corporate	**473.3**	388.1	228.2
	$7,915.7	$ 8,178.0	$ 9,916.6

BUSINESS SEGMENTS	**1984**	1983	1982
CAPITAL EXPENDITURES			
Crude oil and natural gas	**$ 178.8**	$ 358.8	$ 750.7
Natural gas liquids	**13.5**	11.6	32.8
Contract drilling	**9.7**	17.4	45.8
Other	**8.2**	65.3	33.0
	$ 210.2	$ 453.1	$ 862.3
DEPLETION, DEPRECIATION AND AMORTIZATION			
Crude oil and natural gas	**$ 287.5**	$ 260.0	$ 222.4
Natural gas liquids	**20.4**	20.7	25.4
Contract drilling	**52.2**	42.7	36.8
Other	**22.0**	28.4	28.4
	$ 382.1	$ 351.8	$ 313.0

GEOGRAPHIC AREAS			
REVENUE			
Canada	**$2,121.1**	$2,165.6	$2,338.4
United States	**326.5**	429.0	479.6
Other foreign	**—**	—	31.8
	$2,447.6	$2,594.6	$2,849.8
TRANSFERS BETWEEN GEOGRAPHIC AREAS			
Canada	**$ 252.7**	$ 305.4	$ 310.2
United States	**31.2**	16.1	22.8
Eliminations	**(283.9)**	(321.5)	(333.0)
	$ —	$ —	$ —
OPERATING INCOME			
Canada	**$ 746.5**	$ 736.5	$ 790.6
United States	**33.8**	22.2	30.4
Other foreign	**—**	—	5.9
	780.3	758.7	826.9
GAIN (LOSS) ON WRITE-DOWN AND DISPOSAL OF ASSETS			
Canada	**9.6**	(968.0)	(10.9)
United States	**—**	(170.7)	(213.6)
Other foreign	**—**	—	(141.7)
	9.6	(1,138.7)	(366.2)
LOSS (INCOME) BEFORE CORPORATE EXPENSE	**(789.9)**	380.0	(460.7)
CORPORATE EXPENSE (as detailed in Business Segments)	**986.7**	725.0	830.0
NET LOSS	**$ 196.8**	$ 1,105.0	$ 369.3
IDENTIFIABLE ASSETS			
Canada	**$7,052.9**	$7,332.1	$8,515.3
United States	**172.5**	222.1	595.2
Other foreign	**—**	—	21.5
	7,225.4	7,554.2	9,132.0
Deferred foreign exchange	**140.8**	73.2	—
Investments	**549.5**	550.6	784.6
	$7,915.7	$8,178.0	$9,916.6

The majority of the crude oil land natural gas produced in Canada by the Company is sold to government marketing agencies or transmission companies. Approximately 81% of the Company's domestic crude oil production is sold to the Alberta Petroleum Marketing Commission, a provincial government agency. The largest customer for natural gas is TransCanada, which accounts for approximately 48% of the Company's total natural gas sales. The nature of the Company's marketing arrangements is such that the portion of the Company's Canadian crude oil and natural gas production that is ultimately exported cannot be readily identified. The transfers between geographic segments reported above are sales of natural gas liquids.

19. Pension and Savings Plans

The Company's voluntary contributory pension plan and Employee Profit Sharing Plan are available to substantially all of its permanent employees. Employee and Company contributions made under the pension plan are paid to, and invested by, an insurance company. Similar contributions made under the Employee Profit Sharing Plan are invested by the trustees in the common shares of the Company on behalf of the employees. Pension costs are funded in accordance with actuarial requirements. Amounts charged to income to fund the plans (in millions) were: 1984 - $30.3; 1983 - $37.6; 1982 - $36.3. There are no material unfunded past service liabilities at December 31, 1984.

20. Contingencies and Commitments

In addition to the commitments described under Debt Rescheduling Agreement in Long Term Debt, the Company has the following contingent liabilities:

(a) The Company is contingently liable for $225.0 million advanced to Dome Canada by the Arctic Petroleum Corporation of Japan.

(b) In 1983, Revenue Canada-Taxation issued reassessments to the Company disallowing the frontier exploration allowance claimed in 1980. Management believes that these amounts were validly claimed and intends to contest the issue. If the Company is not successful, a prior period adjustment will be made relating to 1980 which will increase the deficit and deferred income taxes by $44.3 million.

There are no pending legal proceedings to which the Company or any of its subsidiaries is a party, or of which any of their properties is the subject, that in management's view would have a material effect on the Company's consolidated financial position or results of operations.

21. Differences Between Canadian and United States Generally Accepted Accounting Principles

The consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian basis"). These principles differ in some respects from those applicable in the United States ("U.S. basis") as disclosed below.

Statements of Operations	Years ended December 31,		
	1984	1983	1982
Net loss in accordance with the Canadian basis as reported	**$196.8**	$1,105.0	$369.3
Add (deduct) adjustments for:			
Full cost accounting (a)	**—**	(341.1)	—
Foreign currency translation (b)	**67.6**	2.0	44.9
Investment tax credit (c)	**6.1**	(6.0)	3.5
Other (d)	**—**	(3.4)	(4.2)
Net loss in accordance with U.S. basis	**$270.5**	$ 756.5	$413.5
Net loss per common share in accordance with U.S. basis	***$ 1.14***	*$ 3.24*	*$ 1.91*

Balance Sheets	December 31,			
	1984		1983	
	Canadian basis	**U.S. basis**	Canadian basis	U.S. basis
Investment in Dome Canada	**$ 412.7**	**$ 437.2**	$ 413.0	$ 437.5
Property, plant and equipment	**6,094.8**	**6,548.2**	6,359.4	6,812.8
Deferred foreign exchange	**140.8**	**—**	73.2	—
Deferred income taxes	**668.1**	**719.2**	369.2	414.2
Redeemable preferred shares issued by the Company	**97.9**	**206.8**	97.9	210.7
Preferred shares	**108.9**	**—**	112.8	—
Deficit (e)	**710.6**	**424.6**	496.4	136.7

Notes to Statements of Operations and Balance Sheets

(a) Under full cost accounting regulations prescribed by the United States Securities and Exchange Commission, the Company is required to accumulate all costs of exploring for and developing oil and gas and related reserves in a single cost centre for Canadian operations. Under these regulations certain costs incurred in frontier areas would not have been charged against income in 1983. The effect of the differing accounting regulations is not material for the year ended December 31, 1984.

(b) FASB Statement No. 52 requires that long term liabilities payable in foreign currencies be translated at the rates of exchange prevailing at the balance sheet date with the resulting translation gains and losses being included in income in the current period. In Canada effective December 31, 1983 these exchange gains and losses are deferred and, commencing January 1, 1984, amortized over the term of the related liabilities. See Changes in Accounting Policies — Foreign Currency Translation.

(c) Under United States generally accepted accounting principles, the Company is required to deduct from the provision for deferred income taxes a portion of the available investment tax credit on eligible expenditures. In Canada, the investment tax credit is only deductible to the extent that the Company believes that it will be realized as a deduction from income taxes.

(d) Comprised of interest capitalized by an equity accounted associate not in accordance with FASB Statement No. 34, and a gain relating to shares in TransCanada which under United States accounting practice would be included in contributed surplus. The difference related to these amounts was eliminated in 1983 when the Company sold its investment in TransCanada. The Company also realized a gain of $10.2 million in 1984 related to an equity issue by Dome Mines. This gain is included in non-operating income in accordance with current United States accounting practice which previously required such gains to be included in contributed surplus.

(e) At December 31, 1984, the deficit of the Company included $124.4 million representing the Company's proportionate share of the cumulative undistributed earnings of equity accounted associates. The Company has not provided for income taxes on this amount as dividends flow tax free between these Canadian companies.

22. Subsequent Events

(a) On February 5, 1985 the Company and certain of its lenders closed the Debt Rescheduling Agreement effective December 31, 1984.

(b) On February 5, 1985, in connection with the closing of the Debt Rescheduling Agreement, the Company issued 12,223,757 common shares at $2.22 per common share having an aggregate value of $27.1 million from which no cash proceeds were received.

(c) On March 11, 1985, the Company sold all of its shares in Davie for nominal consideration.

Unaudited Supplementary Information

(Millions of Canadian Dollars)

The following unaudited supplementary information is disclosed in accordance with the provisions of FASB Statement No. 69 "Disclosures about Oil and Gas Producing Activities".

SEC definitions exclude from oil and gas producing activities the extraction of hydrocarbons from tar sands, and therefore the Company's interests in synthetic crude oil projects are not reflected in the information provided.

Capitalized Costs Relating to Oil and Gas Producing Activities December 31, 1984 and 1983

	1984	1983
Oil and gas properties		
Proved	**$4,514.4**	$4,213.4
Unproved	**1,251.9**	1,433.5
Less accumulated depletion and depreciation	**893.2**	608.3
Net capitalized costs	**$4,873.1**	$5,038.6
Company's proportionate interests in capitalized costs of companies accounted for by the equity method	**$ 513.9**	$ 499.7

Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities Three Years Ended December 31, 1984

	1984			1983			1982		
	Canada	**Foreign**	**Total**	Canada	Foreign	Total	Canada	Foreign	Total
Property acquisition									
Proved	**$ 1.2**	**$ —**	**$ 1.2**	$ 54.2	$ —	$ 54.2	$227.3	$ 0.4	$227.7
Unproved	**—**	**—**	**—**	—	—	—	30.6	—	30.6
Exploration[1]	**85.3**	**—**	**85.3**	155.9	—	155.9	187.5	90.2	277.7
Development[2]	**85.9**	**—**	**85.9**	119.5	24.8	144.3	162.2	34.7	196.9
Company's proportionate interests in costs of property acquisition, exploration, and development of companies accounted for by the equity method	**80.8**	**—**	**80.8**	112.7	9.0	121.7	305.0	12.1	317.1

[1] Includes capitalized interest of $51.2 million (1983 — $129.0 million; 1982 — $196.5 million) and capitalized general and administrative costs of $25.4 million (1983 — $22.6 million; 1982 — $42.4 million).

[2] Includes capitalized interest of $0.5 million (1983 — $6.6 million; 1982 — $4.7 million) and capitalized general and administrative costs of $4.0 million (1983 — $3.5 million; 1982 — $3.0 million).

Results of Operations for Oil and Gas Producing Activities Three Years Ended December 31, 1984

	1984			1983			1982		
	Canada	**Foreign**	**Total**	Canada	Foreign	Total	Canada	Foreign	Total
Revenue	**$1,031.8**	**$ —**	**$1,031.8**	$ 846.9	$ 52.8	$ 899.7	$859.4	$ 100.5	$959.9
Production costs	**236.9**	**—**	**236.9**	193.9	31.8	225.7	197.7	42.5	240.2
Depletion and depreciation	**271.6**	**—**	**271.6**	207.1	36.5	243.6	140.3	67.6	207.9
Write-down of assets	**—**	**—**	**—**	479.6	103.5	583.1	—	213.6	213.6
Loss (gain) on disposal of assets	**(0.4)**	**—**	**(0.4)**	11.3	72.8	84.1	—	141.7	141.7
	523.7	**—**	**523.7**	(45.0)	(191.8)	(236.8)	521.4	(364.9)	156.5
Income tax expense (recovery)	**319.7**	**—**	**319.7**	120.8	(1.8)	119.0	278.6	(50.0)	228.6
Results of operations from producing activities (excluding corporate overhead and interest costs)	**$ 204.0**	**$ —**	**$ 204.0**	$(165.8)	$(190.0)	$(355.8)	$242.8	$(314.9)	$ (72.1)
Company's proportionate interests in results of operations for producing activities of companies accounted for by the equity method	**$ 8.7**	**$ —**	**$ 8.7**	$ (9.2)	$ 1.6	$ (7.6)	$ 12.4	$ —	$ 12.4

Reserve Quantity Information
Three Years Ended December 31, 1984[1]

	Canada		Foreign		Total	
	Oil[2]	Gas	Oil[2]	Gas	Oil[2]	Gas
Proved reserves at December 31, 1981[3]	560,110	7,364	28,593	117	588,703	7,481
Revisions of previous estimates	5,753	(208)	(607)	1	5,146	(207)
Improved recovery	322	—	2,598	—	2,920	—
Extensions and discoveries	10,203	121	7,833	12	18,036	133
Production	(28,640)	(199)	(4,117)	(10)	(32,757)	(209)
Sales of minerals in place	(103,815)	(1,356)	(13,127)	(2)	(116,942)	(1,358)
Proved reserves at December 31, 1982	443,933	5,722	21,173	118	465,106	5,840
Revisions of previous estimates[4]	(110,590)	(863)	(270)	(25)	(110,860)	(888)
Purchase of minerals in place	6,181	101	—	—	6,181	101
Extensions and discoveries	10,990	65	133	—	11,123	65
Production	(25,765)	(166)	(1,785)	(8)	(27,550)	(174)
Sales of minerals in place	(6,636)	(101)	(19,251)	(85)	(25,887)	(186)
Proved reserves at December 31, 1983	318,113	4,758	—	—	318,113	4,758
Revisions of previous estimates	**39,233**	**72**	—	—	**39,233**	**72**
Extensions and discoveries	**10,663**	**89**	—	—	**10,663**	**89**
Production	**(29,354)**	**(196)**	—	—	**(29,354)**	**(196)**
Sales of minerals in place	**(303)**	**(51)**	—	—	**(303)**	**(51)**
Proved reserves at December 31, 1984	**338,352**	**4,672**	—	—	**338,352**	**4,672**
Proved developed reserves at December 31:						
1981	493,064	5,522	23,316	71	516,380	5,593
1982	364,361	3,890	18,629	100	382,990	3,990
1983	249,195	3,174	—	—	249,195	3,174
1984	**267,662**	**3,107**	—	—	**267,662**	**3,107**
Company's proportionate interests in proved reserves of companies accounted for by the equity method at December 31:						
1981	2,803	50	2,748	—	5,551	50
1982	20,521	288	4,580	—	25,101	288
1983	21,924	302	4,512	—	26,436	302
1984	**25,678**	**321**	—	—	**25,678**	**321**

(1) Oil reserves are stated in thousands of barrels; gas reserves are stated in billions of cubic feet.

(2) Includes natural gas liquids reserves of (in millions of barrels): 1984 — 91.6; 1983 — 83.5; 1982 — 103.7; and 1981 — 128.0.

(3) Includes reserves of 261.3 million barrels of crude oil and 3,458 billion cubic feet of gas attributable to HBOG in which there was a 47.1% minority interest at December 31, 1981.

(4) Proved reserves were revised to reflect the results of an independent assessment of the Company's reserves as reported in the April 12, 1984 letter report from Coles Nikiforuk Pennell Associates Ltd. and Mr. Harold Hammar. Although these revisions reduced proved oil and gas reserves by approximately 25% and 15% respectively, the standardized measure of discounted future net cash flows at year end 1983 was higher than the corresponding value at year end 1982. Management believes that these revisions in proved reserves do not represent a major change to the value of the Company's assets.

There have not been any major discoveries or other events since December 31, 1984, that would cause a significant change from the proved reserves reported.

All reserve figures are stated after overriding royalties and freehold royalties but before deduction of provincial royalties. In order to estimate reserves after giving effect to the deduction of provincial royalties, certain assumptions must be made including forecasts of future prices and production. The table below presents reserves as at December 31, 1984, net of all royalties based on independent engineering forecasts of prices, production and other factors necessary to estimate provincial royalties as determined in the independent assessment of the Company's reserves.

	Proved Developed	Proved Undeveloped	Total Proved
Before deduction of Provincial Royalties			
Crude Oil (millions of barrels)	207.0	39.8	246.8
Natural Gas Liquids (millions of barrels) (i)	60.7	30.9	91.6
Natural Gas (billions of cubic feet) (ii)	3,107.4	1,564.8	4,672.2
After deduction of Provincial Royalties			
Crude Oil (millions of barrels)	169.3	35.5	204.8
Natural Gas Liquids (millions of barrels) (i)	44.4	22.6	67.0
Natural Gas (billions of cubic feet) (ii)	2,347.2	1,180.7	3,527.9

(i) Includes condensate.

(ii) Natural gas volumes have been adjusted to a standard heat content of 1000 British thermal units per cubic foot.

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

Future net cash flows are based on year end prices, as determined in accordance with existing regulations, applied to the Company's proved oil and gas reserves after deducting future expenditures to be incurred in developing and producing these reserves. Future income tax expense is computed by applying the statutory tax rates in effect at year end to the future pre-tax net cash flows less the tax basis of the properties involved. A 10% discount factor has been applied in determining the standardized measure of discounted future net cash flow.

The "standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves" disclosed in the following tables may be useful for certain comparison purposes, but should not be construed as representing the fair market value nor the future cash flow of the Company's oil and gas properties. Management does not rely upon this information in making investment and operating decisions; rather those decisions are based upon a wide range of factors, including estimates of probable reserves as well as proved reserves, and price and cost assumptions different from those reflected herein.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves December 31, 1984, 1983 and 1982

	1984			1983			1982		
	Canada	**Foreign**	**Total**	Canada	Foreign	Total	Canada	Foreign	Total
Future cash inflows	**$17,296.1**	**$ —**	**$17,296.1**	$18,291.6	$ —	$18,291.6	$20,231.6	$489.1	$20,720.7
Future production and development costs	**4,729.0**	**—**	**4,729.0**	5,328.8	—	5,328.8	6,473.8	43.0	6,516.8
Future income taxes	**6,151.0**	**—**	**6,151.0**	6,455.4	—	6,455.4	7,882.6	—	7,882.6
Future net cash flows	**6,416.1**	**—**	**6,416.1**	6,507.4	—	6,507.4	5,875.2	446.1	6,321.3
less 10% annual discount for estimated timing of cash flows	**3,165.1**	**—**	**3,165.1**	3,219.4	—	3,219.4	2,935.5	170.2	3,105.7
Standardized measure of discounted future net cash flows	**$ 3,251.0**	**$ —**	**$ 3,251.0**	$ 3,288.0	$ —	$ 3,288.0	$ 2,939.7	$275.9	$ 3,215.6
Company's proportionate interests in standardized measure of discounted future net cash flows of companies accounted for by the equity method	**$ 261.2**	**$ —**	**$ 261.2**	$ 232.5	$21.3	$ 253.8	$ 167.1	$ 26.3	$ 193.4

Principal Sources of Change in the Standardized Measure of Discounted Future Net Cash Flows Three Years Ended December 31, 1984

	1984	1983	1982
Production	**$(801.2)**	$ (722.0)	$ (738.7)
Net changes in prices and production costs	**(539.1)**	282.5	(2,234.2)
Extensions, discoveries and improved recovery, less related costs	**131.1**	114.1	225.9
Development costs incurred during the period	**81.7**	100.7	132.2
Revisions of previous quantity estimates[1]	**260.3**	(1,353.7)	(116.1)
Accretion of discount	**575.8**	617.3	976.1
Net change in income taxes	**(41.7)**	534.3	2,105.2
Sales of reserves in place[2]	**(45.8)**	(287.3)	(1,561.9)
Other — purchase of reserves	**—**	119.4	—
— adjustments and changes	**341.9**	667.1	(227.7)
	$ (37.0)	$ 72.4	$(1,439.2)

[1] Revisions of previous quantity estimates represent the dollar value of changes to proved reserves over and above those due to production, extensions, discoveries and improved recovery results. Reserves have been revised to reflect the results of an independent assessment of the Company's reserves as reported in the April 12, 1984 and March 20, 1985 letter reports from Coles Nikiforuk Pennell Associates Ltd. and Mr. Harold Hammar.

[2] The sales of reserves in 1982 reflect the acquisition by others of an aggregate 34.1% interest in HBOG.

Supplementary Financial Information on the Effects of Changing Prices (Unaudited)

The following supplementary financial information has been prepared in accordance with the recommendations of the Canadian Institute of Chartered Accountants ("CICA"). Reference is made to the Reserve Quantity Information. Although there are differences in the format and in the details of the disclosures, the objectives of the CICA recommendations are similar to those of FASB Statement No. 33.

There is general agreement that the impact of inflation adversely affects the usefulness of information reported in conventional historical cost financial statements. There is controversy on whether the addition of supplementary financial information on the effects of changing prices adequately measures the inflationary impact and whether it contributes to the reader's understanding of reported results. Particularly where assets are resource based, the problems of measuring current cost and the inflation adjustment to operating results have not been definitively resolved.

The CICA recognized the unique nature and the specialized assets of the oil and gas industry, however it concluded that the recommendations should extend to the industry. Their intention is to study reported information over a five year period in order to identify improvements in measurement methods and disclosure.

The Company cautions the reader in the interpretation of the current cost information. The current cost of oil and gas assets proposed by the CICA recommendations is the current cost of either purchasing or finding similar oil and gas reserves. The replacement of the Company's reserves at current cost is hypothetical and in practical terms subject to considerable uncertainty. Actual replacement reserves are more likely to come from non-conventional sources or in the longer term from the frontier and the cost is sensitive to a number of factors including the level of government incentives. Readers should also be cautioned that comparing current cost results between companies may not be meaningful because of the differences in accounting policy and because the recommendations allow certain variations in methodology which can produce materially different results.

The current cost of the Company's producing oil and gas property, plant and equipment and natural gas liquids pipelines and facilities was estimated using the discounted value of future revenues which represents the estimated current acquisition cost of such assets. Current costs for non-producing properties were derived principally from recent purchase prices and farmout valuations. The current cost of the Company's contract drilling equipment is based primarily on engineering estimates of the replacement cost for equivalent assets.

These estimates are made in good faith using assumptions consistent with the CICA recommendations. The precision of these estimates cannot be assured and the Company cautions the reader not to place undue reliance on them.

Reference is made to the accompanying Statements of Operations and Balance Sheet Information which compare the differences between historical cost and current cost information.

The net loss attributable to common shareholders in constant dollars has the objective of indicating the extent to which the general purchasing power of common shareholders' equity was maintained during the period.

There are four adjustments to the historical cost statement. The first indicates that the net loss on the current cost basis increased $113 million (1983 — $98 million) when compared to the historical net loss. The two contributing factors are a decrease of $2 million (1983 — increase of $12 million) in the cost of natural gas liquid product and an increase of $115 million (1983 — $86 million) in depletion, depreciation and amortization measured on the current cost basis.

The second adjustment is the increase in the current cost from holding inventory and property, plant and equipment and amounts to $96 million (1983 — $133 million).

The third and fourth adjustments reflect the effect of changes in the general purchasing power of the dollar. The increase in the current cost of inventory and property, plant and equipment attributable to the effects of general inflation amounts to $318 million (1983 — $437 million). This charge, net of the adjustment of $96 million (1983 — $133 million) discussed above, is a measure of the extent to which the current cost of these assets has kept pace with general inflation as measured by the Consumer Price Index. The second general purchasing power adjustment included in the CICA recommendations is a gain from holding net monetary liabilities. The Company's debt significantly exceeds its monetary assets of cash and accounts receivable. To the extent of inflation in 1984, the holding of the net monetary obligations represented a gain of $256 million (1983 — $341 million) to the Company, since less purchasing power is required to repay the obligations.

The current cost of inventory and property, plant and equipment shows an excess over historical cost of $1,995 million (1983 — $2,092 million) which relates primarily to oil and gas, natural gas liquids, and contract drilling. While this excess is calculated in accordance with the CICA recommendations, this should not be viewed as a valuation of the Company. For example, valuation adjustments with respect to other assets of the Company, such as its investment in associated companies, are not included.

Additional Disclosure:

The CICA requires disclosure of a financing adjustment. It allocates a portion of the change in current cost to the holders of debt and preferred shares. The financing adjustment is $79 million (1983 — $102 million) of the $96 million increase (1983 — $133 million) in the current costs of assets and $92 million (1983 — $76 million) of the $113 million (1983 — $98 million) additional cost of natural gas liquid product and depreciation, depletion and amortization.

Effects of Changing Prices
Two Years Ended December 31, 1984

(Millions of Canadian dollars)

STATEMENTS OF OPERATIONS	1984 Historical Cost Basis	1984 Current Cost Basis	1983 Historical Cost Basis	1983 Current Cost Basis
Revenues	**$2,448**	**$2,448**	$2,708	$2,708
Operating expense including cost of natural gas liquid product	**1,285**	**1,283**	1,549	1,561
Depreciation, depletion and amortization	**382**	**497**	367	453
Preferred share dividends of subsidiaries	**16**	**16**	35	35
Write-down and loss (gain) on disposal of assets	**(40)**	**(40)**	1,215	1,215
Other expenses	**992**	**992**	768	768
Income taxes	**38**	**38**	(27)	(27)
Equity in earnings of associated companies	**(28)**	**(28)**	(46)	(46)
Net loss	**197**	**310**	1,153	1,251
Preferred share dividends	**12**	**12**	13	13
Increase in the current cost of inventory and property, plant and equipment held during the year	**—**	**(96)**	—	(133)
Net loss attributable to common shareholders in nominal dollars	**$ 209**	**226**	$1,166	1,131
Increase in current cost of inventory and property, plant and equipment attributable to the effect of general inflation		**318**		437
Gain in general purchasing power from holding net monetary liabilities		**(256)**		(341)
Net loss attributable to common shareholders in constant dollars		**$ 288**		$1,227

The 1983 comparative amounts have been restated in (approximately) 1984 average dollars.

BALANCE SHEET INFORMATION	December 31, 1984 Historical Cost Basis	December 31, 1984 Current Cost Basis	December 31, 1984 Excess	December 31, 1983 Historical Cost Basis	December 31, 1983 Current Cost Basis	December 31, 1983 Excess
Inventory	**$ 224**	**$ 225**	**$ 1**	$ 245	$ 248	$ 3
Property, plant and equipment	**6,095**	**8,089**	**1,994**	6,598	8,687	2,089
Net assets (common shareholders' equity)	**(529)**	**1,466**	**1,995**	(356)	1,736	2,092

The 1983 comparative amounts have been restated in December, 1984 dollars.

Selected Quarterly Financial Data (Unaudited)

(Millions of Canadian Dollars, Except per Share Amounts)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
1984					
Revenue	**$634.3**	**$551.1**	**$579.7**	**$682.5**	**$2,447.6**
Operating income[1]	**199.5**	**192.9**	**189.6**	**198.3**	**780.3**
Net income (loss)	**(39.6)**	**(61.6)**	**(4.2)**	**(91.4)**	**(196.8)**
Net income (loss) per common share	***(0.18)***	***(0.26)***	***(0.02)***	***(0.38)***	***(0.84)***
1983 [3]					
Revenue	675.0	575.0	610.7	733.9	2,594.6
Operating income[1] [2] before write-down and losses on disposal of operating assets	208.9	206.2	212.4	131.2	758.7
Operating income[1] [2] after write-down and losses on disposal of operating assets	209.7	110.8	210.6	(911.1)	(380.0)
Net income (loss)	7.2	(86.0)	10.3	(1,036.5)	(1,105.0)
Net income (loss) per common share	*0.02*	*(0.38)*	*0.03*	*(4.39)*	*(4.72)*

[1] Operating income is after operating expense, depletion, depreciation and amortization but before corporate expense.

[2] The results for the second and fourth quarters and the year 1983 were affected significantly by write-downs and losses on disposal of assets.

[3] Certain 1983 comparative amounts have been restated to conform with the presentation adopted in 1984.

Market for the Company's Equity and Related Shareholder Matters

The principal public trading market for the Company's common shares in Canada is The Toronto Stock Exchange. The market on which the Company's common shares are listed for trading in the United States is the American Stock Exchange. The following table sets forth the high and low prices and trading volumes for the Company's common shares on the Toronto and Montreal stock exchanges and on the American Stock Exchange for the periods indicated.

	Toronto and Montreal Stock Exchanges (Canadian Dollars)			American Stock Exchange (United States Dollars)		
1983	High	Low	Volume (Thousands)	High	Low	Volume (Thousands)
1st quarter	$4.90	$3.10	16,000.4	$4.00	$2.50	23,974.9
2nd quarter	7.00	3.60	18,326.5	5.75	2.88	29,801.9
3rd quarter	6.25	4.80	7,015.6	5.00	3.88	12,190.4
4th quarter	5.13	3.90	8,228.9	4.19	3.13	11,997.3
1984						
1st quarter	**4.55**	**3.65**	**7,723.4**	**3.69**	**2.94**	**13,728.8**
2nd quarter	**4.05**	**3.00**	**6,466.0**	**3.19**	**2.19**	**10,107.9**
3rd quarter	**3.35**	**2.10**	**11,806.2**	**2.63**	**1.56**	**14,909.7**
4th quarter	**3.05**	**2.07**	**6,250.7**	**2.31**	**1.56**	**13,278.6**

The number of registered holders of common shares of the Company on March 19, 1985 was 47,159. The Company has not paid dividends on its common shares since its inception. Under the terms of the Debt Rescheduling Agreement, the Company is prohibited from paying cash dividends on its common shares until 1989. Thereafter, dividend payments will be limited by a formula based on earnings. The terms of outstanding series of the Company's preferred shares also impose restrictions on the Company's ability to declare and pay dividends on its common shares if dividends on the preferred shares are in arrears for specified periods or if certain earnings tests are not met. Such earnings restrictions would currently preclude the payment of dividends on the common shares. However, even if dividend payments are permitted under the Company's debt covenants and the terms of outstanding series of the Company's preferred shares, the declaration and payment of dividends on the Company's common shares is at the discretion of the Board of Directors.

Five Year Financial Review

(Millions of Canadian Dollars, Except per Share Amounts)

	1984	1983	1982	1981	1980
Revenue (after royalties and revenue taxes)					
Oil and gas operations					
Crude oil and field natural gas liquids	**$ 650.7**	$ 606.4	$ 571.3	$ 410.9	$ 188.6
Natural gas	**367.9**	324.6	371.1	284.4	204.8
Sulphur and other	**69.7**	15.4	61.4	25.7	16.0
Total crude oil and natural gas	**1,088.3**	946.4	1,003.8	721.0	409.4
Natural gas liquids	**1,012.5**	1,135.4	1,044.3	866.3	637.2
Contract drilling	**335.7**	409.3	505.7	412.6	74.6
Other	**11.1**	103.5	296.0	172.4	—
	2,447.6	2,594.6	2,849.8	2,172.3	1,121.2
Expense					
Operating expense					
Crude oil and natural gas	**268.4**	249.2	264.7	209.3	68.5
Natural gas liquids	**833.6**	894.9	804.7	631.7	460.9
Contract drilling	**171.3**	221.0	315.7	238.4	40.9
Other	**11.9**	119.0	324.8	182.3	—
Depletion	**218.4**	213.7	185.3	99.7	53.6
Depreciation and amortization	**163.7**	138.1	127.7	63.7	29.3
Write-down of assets	—	1,099.0	213.6	—	—
Loss (gain) on disposal of assets	**(39.8)**	65.0	154.6	(18.3)	(0.3)
General and administrative	**82.9**	110.7	98.7	46.1	21.7
Interest on long term debt	**710.8**	679.3	789.2	666.9	288.3
Less interest capitalized	**(51.7)**	(136.8)	(212.9)	(215.1)	(142.4)
Other interest and financing charges	**163.5**	71.0	67.2	57.9	8.2
Foreign exchange	**123.0**	26.6	22.6	11.1	(4.0)
Preferred share dividends of subsidiaries	**15.7**	34.1	163.5	24.0	18.2
Other corporate revenue	**(36.9)**	(14.9)	(67.1)	(24.7)	(22.1)
Gain on cancellation of preferred shares	—	—	(70.0)	—	—
	2,634.8	3,769.9	3,182.3	1,973.0	820.8
	(187.2)	(1,175.3)	(332.5)	199.3	300.4
Provision for income taxes	**38.1**	(26.1)	93.9	78.2	84.3
Equity in earnings of associated companies	**28.5**	44.2	57.1	78.0	71.1
Net income (loss)	**$ (196.8)**	$(1,105.0)	$ (369.3)	$ 199.1	$ 287.2
Average number of common shares outstanding (in millions)	**248.5**	236.8	223.8	223.4	221.5
Net income (loss) per common share	***$ (0.84)***	*$ (4.72)*	*$ (1.71)*	*$ 0.80*	*$ 1.20*
Cash from operations[a]	**$ 208.9**	$ 198.4	$ 103.6	$ 84.6	$ 257.5
Capital expenditures and acquisitions[b]					
Crude oil and natural gas	**$ 97.7**	$ 193.5	$ 494.3	$ 2,593.3	$ 1,317.2
Natural gas liquids	**13.5**	11.0	29.0	102.2	71.4
Contract drilling	**9.7**	17.4	42.9	245.2	21.4
Other	**8.2**	65.3	29.4	518.6	49.4
	$ 129.1	$ 287.2	$ 595.6	$ 3,459.3	$ 1,459.4
Total assets	**$ 7,915.7**	$ 8,178.0	$ 9,916.6	$10,208.7	$ 5,078.7
Long term debt obligations and redeemable preferred shares (excluding current portion)	**$ 6,415.4**	$ 4,068.7	$ 4,615.5	$ 6,628.4	$ 3,025.8

[a] The Company formerly reported funds generated from operations, a working capital definition versus the cash definition adopted in 1984. For the purpose of continuity and to facilitate comparison with other companies, funds generated from operations for 1984 were $484.1 (1983 — $201.1; 1982 — $224.0; 1981 — $388.5; and 1980 — $449.6).

[b] Exclusive of capitalized interest and general and administrative expenses.

The financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada. If the financial statements had been prepared in accordance with accounting principles generally accepted in the United States certain of the financial data above would be restated as follows:

	1984	1983	1982	1981	1980
		(Millions of Canadian Dollars, Except per Share Amounts)			
Net income (loss)	**$ (270.5)**	$ (756.5)	$ (413.5)	$ 243.9	$ 291.4
Net income (loss) per share	***$ (1.14)***	*$ (3.24)*	*$ (1.91)*	*$ 1.00*	*$ 1.21*
Write-down of assets	—	$ (645.6)	$ (213.6)	$ —	$ —
Long term obligations	**$ 6,524.3**	$ 4,181.5	$ 4,803.3	$ 6,746.8	$ 3,186.4
Total assets	**$ 8,252.8**	$ 8,582.7	$ 9,915.2	$10,203.3	$ 5,077.4

Five Year Operating Review

	1984	1983	1982	1981	1980
Production Volumes[1]					
Crude oil (thousands of barrels per day)					
Canada — conventional and heavy	**66.8**	61.7	64.7	56.7	37.2
— synthetic	**3.2**	4.1	3.2	2.7	—
Foreign	—	2.7	8.5	9.5	3.0
Natural gas liquids — field plants	**13.6**	13.7	16.5	10.0	1.9
Total petroleum liquids	**83.6**	82.2	92.9	78.9	42.1
Natural gas (millions of cubic feet per day)	**551**	485	585	476	344
Sulphur (long tons per day)	**994**	885	826	577	—
Natural gas liquids — straddle plants (thousands of barrels per day)	**34.0**	27.8	30.8	29.9	29.6
Sales Volumes[1]					
Natural gas liquids (thousands of barrels per day)	**110.2**	116.3	122.9	118.8	101.4
Sulphur (long tons per day)	**1,721**	1,112	2,126	804	—
Gross Wells (including farmouts)					
Exploratory — Canada — oil	**67**	62	110	68	75
— gas	**41**	46	129	226	214
— dry	**97**	58	111	147	137
Exploratory — Foreign — oil	—	1	14	32	23
— gas	—	—	7	11	6
— dry	—	2	53	86	59
Total gross exploratory wells	**205**	169	424	570	514
Development — Canada — oil	**729**	601	280	274	238
— gas	**221**	131	264	339	342
— dry	**113**	72	72	71	95
— Foreign — oil	—	26	60	164	42
— gas	—	5	24	30	55
— dry	—	5	13	38	36
Total gross development wells	**1,063**	840	713	916	808
Total gross wells	**1,268**	1,009	1,137	1,486	1,322
Reserves (millions of barrels)[2]					
Estimated reserves of oil, natural gas liquids and oil equivalent of natural gas	**1,201**	1,200	1,541	1,969	1,010
Land Holdings (thousands of acres)					
Gross working interest	**57,957**	66,291	72,343	123,322	70,514
Net working interest	**24,597**	26,798	27,825	53,867	31,557
Gross royalty interest[3]	**11,677**	11,689	10,807	28,422	26,737

(1) Production and sales volumes are before deduction of all royalties and particpation interests of host governments.

(2) Stated before Crown but after other royalties. 1984 and 1983 values reflect consultants' proved reserves estimates, defined by the SEC, plus 56.6 million (1983 — 61.5 million) barrels of synthetic crude oil. Established reserves for prior years were determined by the Company's engineers. Natural gas has been converted to oil equivalent based on heat content.

(3) These are lands in which only a royalty interest is held. The Company also holds royalty interests (at December, 1984), in approximately 15.9 million gross acres of its working interest lands.

Exchange Rates

Since June 1, 1970, the Government of Canada has permitted the Canadian dollar to float against the United States dollar and other foreign currencies. The exchange rates at the end of each of the 5 years ended December 31, 1984 and the average, the high and the low exchange rates for the 5 years then ended were as follows (such rates, which are expressed in United States dollars, being the noon buying rates in New York City for cable transfers in Canadian dollars as certified for customs purposes by the Federal Reserve Bank of New York).

	1984	1983	1982	1981	1980
Annual Average	**$.7720**	$.8114	$.8101	$.8340	$.8552
Last day	**.7566**	.8035	.8132	.8430	.8372
High in year	**.8033**	.8201	.8430	.8499	.8754
Low in year	**.7492**	.7993	.7691	.8048	.8258

Directors

Norman J. Alexander,*,**
Winnipeg, Manitoba
Investment Consultant

John M. Beddome,
Calgary, Alberta
President and Chief
Operating Officer

Harold Bridges,
Vaud, Switzerland
Retired Energy Executive

Marshall A. Crowe,**
Ottawa, Ontario
President, M.A. Crowe
Consultants, Inc.
An energy consultant

Fraser M. Fell, Q.C.,**
Toronto, Ontario
Chairman of the Board
and Chief Executive
Officer of Dome Mines
and subsidiaries

Maclean E. Jones,*,**
Calgary, Alberta
Partner in the law firm of
Bennett Jones

Allen T. Lambert,**
Toronto, Ontario
Chairman of the Board of
Trilon Financial
Corporation

James G. Livingstone,**
Toronto, Ontario
Retired Energy Executive

J. Howard Macdonald,**
Calgary, Alberta
Chairman, Chief
Executive Officer and
Chief Financial Officer

Harold P. Milavsky,
Calgary, Alberta
President and Chief
Executive Officer,
Trizec Corporation Ltd.

Frederick B. Whittemore,*
New York, N.Y.
A managing director of
Morgan Stanley & Co.
Incorporated
Investment bankers

* Audit Committee Member
** Executive Committee Member

Officers

J. Howard Macdonald
Chairman, Chief Executive
and Chief Financial Officer

John M. Beddome
President and
Chief Operating Officer

John Andriuk
Senior Vice-President,
Exporation & Land

H. James Strain
Senior Vice-President,
Frontier & Drilling

Murray B. Todd
Senior Vice-President,
Production & Development

A. Boyd Anderson
Vice-President, Marketing
& Corporate Planning

Earle L. Forgues
Vice-President,
Natural Gas Liquids

Dean P. Geddes
Vice-President, Production

Robert W. Gillanders
Vice-President,
Business Development

Michael A. Grandin
Vice-President, Land

Brian F. Little
Vice-President and
General Counsel

John R. Moore
Vice-President, Exploitation

Stephen J. Savidant
Vice-President, Human
Resources & Administration

Robert M. Scarborough
Vice-President, Heavy Oil

George W. Watson
Vice-President, Finance

Karl G. Leitl
Controller

Ernest F. H. Roberts
Treasurer

John F. Scott
Secretary

E. Susan Evans
Assistant Secretary

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Stock Listing

Toronto Stock Exchange
Montreal Exchange
American Stock Exchange
(common shares only)
London Stock Exchange
(common shares only)

Registrars and Transfer Agents

Common Shares
Canada Permanent
Trust Company
Calgary, Montreal, Toronto
and Regina

The Bank of New York
New York, N.Y.

Preferred Shares
Series A and B:
The National Victoria and Grey
Trust Company
Calgary, Montreal, Toronto
and Vancouver

Auditors

Clarkson Gordon
Calgary, Alberta

Additional Information

Shareholders with questions regarding share certificates, registration and change of address, share valuation, dividends, proxies and other related shareholder business write to:

Corporate Secretary
Dome Petroleum Limited
P.O. Box 200
Calgary, Alberta, Canada
T2P 2H8

To request a copy, without charge, of the 1984 Annual Report or Form 10-K as filed with the Securities and Exchange Commission of the United States write to:

Public Affairs Department
Dome Petroleum Limited
P.O. Box 200
Calgary, Alberta, Canada
T2P 2H8

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