DOME PETROLEUM LIMITED ANNUAL REPORT 1985

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The Company

Dome Petroleum Limited, incorporated in Canada in 1950, is a major participant in the Canadian oil and gas industry. The Company's operations are comprised of three core business segments: the exploration for and production of crude oil, natural gas and natural gas liquids in Canada; the transportation and marketing of NGL in Canada and the United States, and contract drilling in the Beaufort Sea under the trade name Canmar. Dome currently owns 48 per cent of Dome Canada Limited and 23.2 per cent of Dome Mines Limited. Dome Mines, holding 22.0 per cent of Dome Petroleum's common shares at the 1985 year-end, is the Company's major shareholder.

The Company's common shares are traded on the Toronto, Montreal, American and London Stock Exchanges.

Contents

PANARCTIC FARMINS

Code	Farmor	Gross Acreage
P	Panarctic 100%	5,394,162.0
1	Domex Group	4,030,395.0
2	Great Plains	3,863,359.5
3	Triceetee Group	3,687,097.5
4	Bankeno/Cominco	3,637,783.5
5	BP Exploration	3,297,362.0
6	United Canso	2,783,731.0
7	Dome	2,307,102.5
8	Elf	2,327,187.5
9	Alminex	1,986,823.0
10	Bankeno/Cominco et al	1,920,934.0
11	Francana	1,779,247.0
12	Prairie Oil Royalties	1,526,214.0
13	Consumers' Co-op	1,482,544.0
14	Ashland	1,316,547.0
15	Plains et al	1,303,878.0
16	Homestead	1,225,652.5
17	Standard Oil of B.C.	960,086.0
18	C.I.G.O.L.	822,704.5
19	Lassiter Kuma	722,637.0
20	Canada Southern	709,135.5
21	Pembina Pipe Line	660,983.0
22	Canadian-Montana	495,398.0
23	Norpet	449,365.5
24		
25	Northwest Gas & Oil	85,490.5
26	Canada Southern/BP Exploration	62,650.0
27	Canada Southern/Clark/Skelly	57,210.0
28	Acroll (Axel Heiberg Is.)	25,324.0
29	Acroll (Ellef Ringnes Is.)	24,958.0
30	Western Minerals	792,620.5
31	Troy	532,795.0
32	Homestead (Sabine Pen.)	30,420.0
33	Acroll (Mackenzie King Is.)	302,287.0
34	Toltec	3,491,169.0
35	Nortun	93,973.0
36	Magnorth	405,707.0
37	Pan Ocean et al	1,294,139.0
38	Zorayda et al	40,529.0
39	Axel Heiberg et al	50,831.0
40	Hammond (Sabine Pen.)	31,505.0
41		
42	Acroll (Sabine Pen.)	60,749.0
43	Canada Southern	3,650,607.0
44	Sunoco et al	(Option Not Exercised)
45	Drillarctic	159,671.0
46	Hammond (Axel Heiberg Is.)	22,206.0
47	Thouvenelle	263,129.5
		60,168,300.0

PANARCTIC FARMOUTS

	Company	Gross Acreage
A	Sunoco	4,454,756.0
B	BP	949,660.0
C	Deminex	1,136,091.0
D	Imperial	1,299,024.5
E	Gulf	1,175,556.0
F	Total Pete.	37,782.0
G	Imperial-Drillarctic	189,036.0
H	Atlantic Richfield	395,570.0
I	Cities Service	119,109.0
J	Canadian Reserve (bottom hole contribution)	
K	Canadian Homestead	249,959.5
		10,006,544.0

INDUSTRY DRILLING IN THE ARCTIC ISLANDS

	Well Name	Depth	Status	R.R. Date
1	Dome et al Winter Harbour #1	12,541′	Abandoned	April 1962
2	Lobitos et al Cornwallis Resolute B. L-41	4,841′	Abandoned	Dec. 1963
3	Dominion Explorers Canso et al Bathurst Cale. J-34	10,000′	Abandoned	Feb. 1964
4	Panarctic Sandy Point L-46	6,895′	Abandoned	July 1969
5	Panarctic Marie Bay D-02	4,175′	Abandoned	Sept. 1969
6	Panarctic Drake Point N-67 (Formerly L-67)	8,454′	Gas Discovery Blew wild Killed by K-67	July 1969 Sept. 1970
7	Panarctic Drake Point L-67 (Formerly K-67A)	10,671′	Gas Discovery	Nov. 1969
8	Panarctic Drake Point L-67A Plugged back directional relief well (Formerly K-67A directional)	3,966′	Relief hole unsuccessful now capped gas well	May 1970
9	Panarctic Drake Point K-67	3,198′	Relief hole Killed Abandoned	Nov. 1970
10	Panarctic Towson Point F-63 (Formerly G-63)	5,123′	Abandoned	June 1970
11	Elf Cape Norem A-80	9,744′	Abandoned	Aug. 1970
12	Panarctic Hoodoo-Dome H-37 (Formerly F-27)	11,072′	Abandoned	Aug. 1970
13	Panarctic Homestead Hecla J-60	11,864′	Abandoned	Sept. 1970
14	Panarctic King Christian D-18	2,010′	Gas Discovery Killed by D-18A & Abandoned	 Oct. 1970 Jan. 1971
15	Panarctic King Christian D-18A Directional relief and evaluation well	2,779′	Completed as Capped Gas Well	March 1971
16	Elf Wilkins E-60	11,140′	Abandoned	Jan. 1971
17	Sun K.R. Panarctic Kitson R. C-71	9,075′	Abandoned	Feb. 1971
18	Panarctic Amund Central Dome H-40	11,030′	Abandoned	April 1971
19	Sun K.R. Panarctic Allison R. N-12	11,761′	Abandoned	March 1971
20	Elf Jameson Bay C-31	8,327′	Abandoned	May 1971
21	Panarctic Deminex Cornwallis Central Dome K-40	10,052′	Abandoned	Aug. 1971
22	Panarctic Deminex Garnier O-21	6,515′	Abandoned	July 1971
23	Sun Panarctic Young Inlet D-21	6,058′	Abandoned	July 1971
24	Panarctic King Christian N-06	11,020′	Gas Well	Sept. 1971
25	Sun K.R. Panarctic Skybattle Bay C-15	12,000′	Abandoned	Nov. 1971
26	Panarctic Fosheim N-27	14,022′	Abandoned	Dec. 1971
27	BP et al Panarctic Hotspur J-20	12,584′	Abandoned	Dec. 1971
28	Sun Panarctic Russell H-92	6,020′	Abandoned	Jan. 1972
29	BP et al Panarctic Satellite F-68	12,075′	Abandoned	May 1972
30	Elf et al Storkerson Bay A-15	6,719′	Abandoned	Dec. 1971
31	Panarctic Tenneco et al Kristoffer Bay G-06	12,877′	Gas Discovery	March 1972
32	Imp IOE Panarctic et al Devon E-45	6,030′	Abandoned	March 1972
33	Panarctic B.P. Skelly Tenneco et al Brock C-50	12,996′	Abandoned	March 1972
34	Panarctic Romulus C-42	14,940′	Abandoned	July 1972
35	Panarctic Gulf Dumbbells E-49	11,182′	Abandoned	May 1972
36	Elf Nanuk D-76	4,518′	Abandoned	March 1972
37	BP et al Graham C-52	10,100′	Abandoned	May 1972
38	Panarctic Gulf Helicopter J-12	12,512′	Abandoned	Nov. 1972
39	Elf Uminmak H-07	5,573′	Abandoned	May 1972
40	Imp Panarctic Dome et al Hoodoo L-41	14,040′	Abandoned	July 1972
41	Panarctic Gulf West Amund I-44	3,137′	Abandoned	April 1972
42	Panarctic Tenneco et al Thor P-38	6,000′	Oil Discovery	May 1972
43	Panarctic Brock I-20	10,422′	Abandoned	June 1972
44	Panarctic Tenneco et al POR Drake Point F-16	4,850′	Gas Well	June 1972
45	Panarctic Dome Tenneco et al Dome Bay P-36	8,050′	Abandoned	July 1972
46	Panarctic Tenneco et al POR Drake B-44	4,580′	Gas Well	Oct. 1972
47	Panarctic Noice G-44	5,791′	Abandoned	Oct. 1972
48	Panarctic Dome Dundas C-80		Drilling	
49	Panarctic Gemini E-10		Drilling	
50	Horn R. Panarctic et al Depot Pt. L-24		Drilling	
51	Imp Panarctic et al Mokka A-02		Drilling	
52	BP et al Panarctic Emerald K-33		Location	
53	Panarctic Tenneco et al POR Hecla F-62	4,000′	Gas Discovery	Dec. 1972
54	Sun Gulf Global Linckens Island P-46		Location	
55	Panarctic Dome Tenneco et al Louise O-25		Drilling	
56	Horn River CCS Getty Mid Fiord K-52		Location	
57	Deminex CGOC FOC Amoco Orksut I-44		Location	
58	Panarctic Tenneco et al Pollux G-60		Location	
59	Dome Arctic Ventures Wallis K-62		Drilling	

December 31, 1972

The Year in Review

- *Financial results improved markedly in 1985. Net earnings were positive, and cash from operations amounted to $542 million. By year end we had built a large cash balance.*

- *Dome signed an agreement with its lenders to reschedule $5.3 billion of debt over 12 years. We satisfied three major commitments of the agreement by launching a successful equity issue, selling 10 million shares of Dome Mines Limited, and completing $150 million in asset sales.*

- *Production and sales of natural gas, natural gas liquids and synthetic crude oil increased from 1984 levels, while conventional crude oil production remained level.*

- *Dome's Canmar contract drilling organization successfully completed its first drillship contract in the U.S. Beaufort Sea.*

- *Oil prices were deregulated in Canada, and full deregulation of natural gas will be phased in by November, 1986. Some taxes and royalties are being progressively reduced. Dome continued to strive for superiority in marketing, which is becoming increasingly important in a deregulated environment.*

- *Weak crude oil prices in late December foreshadowed a precipitous drop in 1986 to less than half the year-end level. The price collapse will have a severe impact on 1986 results. Dome is deferring certain debt payments and has proposed an interim plan to its lenders in order to avoid a liquidity problem.*

Highlights

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

		1985	1984	1983
Financial	Total revenue	**$2,436**	$2,448	$2,595
	Operating income before write-downs and gains (losses) on disposal of assets	**847**	795	776
	Net income (loss)	**7**	(197)	(1,105)
	Net income (loss) per common share	**(0.02)**	(0.84)	(4.72)
	Cash from operations	**542**	209	199
	Capital expenditures	**139**	129	287
Operations	Oil and field natural gas liquids production (thousands of barrels/day)	**87**	84	82
	Natural gas production (millions of cu. ft./day)	**591**	551	485
	Natural gas liquids production from straddle plants (thousands of barrels/day)	**35**	34	28
	Natural gas liquids sales (thousands of barrels/day)	**113**	110	116
	Gross wells drilled, including farmouts	**1,510**	1,268	1,009

To The Shareholders:

A series of events over the past year has greatly altered the economic environment for the Canadian petroleum industry. The most notable of these changes were deregulation of crude oil prices, the beginning of a deregulation process for natural gas, and major revisions in both provincial and federal fiscal and regulatory regimes. These changes were followed by a sharp drop in world crude oil prices which began in December, 1985 and intensified during 1986.

The result for Dome was a favorable environment during 1985, followed by extremely difficult conditions in the opening months of the new year.

Financial Highlights

During 1985, Dome Petroleum was able to implement key elements of its financial plan, signing an agreement with lenders to reschedule its debt over an extended period, followed by a successful equity issue. We continued to achieve efficiencies in operations and reductions in administrative expenses. Lower interest rates and higher average oil prices improved our operating environment.

Together, these factors resulted in improved financial results for 1985. For the first time in four years we achieved a small net income. Strong cash flows from operations, coupled with cash raised from the equity issue and asset sales, enabled us to meet our obligations, to make prudent capital expenditures and to build a strong cash balance by year end.

The closing of the Debt Rescheduling Agreement in February, 1985 was the culmination of an enormous effort by Dome and its lenders. Principal payments on \$5.3 billion, or 83 per cent of our debt, were extended over a 12 year period to 1995. In the Debt Rescheduling Agreement we agreed that by December 31, 1986 we would raise \$100 million through the sale of equity, sell \$150 million of assets, and sell 10 million of our Dome Mines Limited shares.

We have already met all of these commitments. In May, we completed an international equity issue with the sale of 34 million common shares and 17 million common share purchase warrants which raised a net \$114 million. We also realized \$142 million from asset sales during the year. In early 1986 we sold 10 million of our 31 million common shares in Dome Mines for additional net proceeds of \$147 million, completing our asset and share sale commitments.

Operating Highlights

Operating income for the year improved from 1984, due principally to oil price increases and improved margins in natural gas liquids sales. Crude oil production volumes were maintained at 1984 levels, while those of natural gas and natural gas liquids increased. On average, crude oil prices were higher, NGL prices were virtually unchanged, and those for natural gas declined.

During the year oil prices were deregulated, regional border pricing was introduced for exports of natural gas, and a one-year transition period commenced for decontrol of natural gas prices and markets in Canada. The fiscal regime was improved with the phase-out of the federal Petroleum and Gas Revenue Tax by the end of 1988, and by some reductions in provincial royalties. On April 1, 1986, Petroleum Incentive Program (PIP) grants for exploration and development activity ceased, except for some grandfathering in frontier areas. PIP grants, which heavily favored Canadian owned and controlled companies, were replaced in the Frontier by a non-discriminatory but less generous tax-based incentive system.

Current Situation

During the first quarter of 1986 there was an unprecedented and rapid decline in world crude oil prices to less than half of the year-end 1985 level.

To avoid a serious erosion of liquidity, we have approached our lenders who are party to the DRA with an interim plan whereby interest and principal payments would be reduced for certain lenders and suspended for certain other lenders for an interim period from May 1 to October 28, 1986, or February 28, 1987 if extended.

Dome is seeking agreement from its lenders to the interim plan by May 30, 1986 and has obtained agreement to defer payments due from April 30, 1986 to that date to allow time to finalize the interim plan.

Dome will develop a permanent plan before the interim plan expires. The ongoing viability of the Company depends on reaching agreement with the lenders on both an interim and permanent plan.

Outlook

In the near term, we anticipate continued unstable, low energy prices. However, we expect the decrease in worldwide investment for the development of energy supplies, coupled with modest increases in world oil demand will eventually result in a recovery of prices in the longer term, but we cannot predict when such a recovery will occur.

The other key economic factors which will affect Dome's results are interest rates and government policy. Although United States rates declined during early 1986, the Canadian prime rate rose from 10 per cent at the start of the year to a high of 13 per cent during February and March, and fell back to 10.5 per cent on May 1. We expect that, over time, continued lower energy prices would have a downward effect on interest rates.

Dome is maintaining its operating infrastructure required for recovery and growth when economic conditions improve. Our very large landholdings and reserves in Western Canada, our extensive oil and gas production facilities and integrated NGL system, and our unique contract drilling equipment and services will provide cash flow and the basis for future development, assuming that agreement can be reached with our lenders on an interim and a permanent plan.

We have made impressive progress in reducing costs and optimizing productivity in our operations. These efficiencies are due to the skill and dedication of employees throughout the organization, and we wish to thank these people for their solid contributions. A section of this annual report highlights several examples of our employees continuing to find ways to improve our operational efficiency.

Directors and Officers

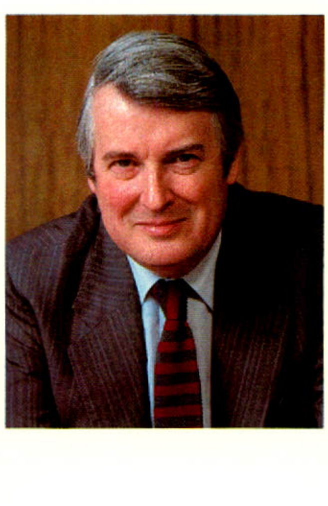
No changes have been made to the board of directors since the 1985 annual meeting of shareholders.

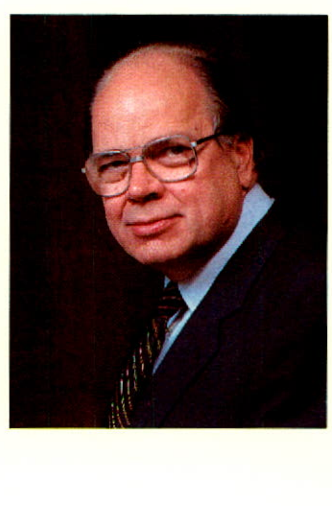
During the year two new officers were appointed — Roy G. Millice to vice-president, exploration, and James C. Smith to vice-president, human resources and administration.

J. Howard Macdonald
Chairman

John M. Beddome
President

Calgary
May 1, 1986





Oil and Gas Operations

1985: A year of substantial progress

In 1985 the oil and gas business segment generated more than 70 per cent of our cash operating income. This income was up six per cent from 1984, reflecting higher oil prices and increased synthetic oil and natural gas liquids (NGL) production. Natural gas volumes also increased, but that benefit was offset by lower prices.

Dome drills 1,510 wells

Dome remained the largest oil and gas landholder in Western Canada and conducted an active drilling program on its lands, with 1,510 wells drilled in 1985. In the Beaufort Sea, we were encouraged by our discovery at Adlartok, which flowed oil on test at over 4,100 barrels per day.

In 1985, more than 80 per cent of Dome's direct capital expenditures were invested in oil and gas, largely on development. An active farmout program funded most of our exploration and many development wells.

The sharp decline in world oil prices in early 1986 will have a significant negative impact on the revenue and operating income from this segment. Dome has significantly reduced its 1986 budget for capital expenditures and has shut in some higher cost production.

Crude Oil and Field NGL - Production and Markets

Oil volumes are level; natural gas and NGL production increase

Dome is a major Canadian producer of crude oil. In 1985 we produced 70,100 barrels per day, representing 4.7 per cent of industry volumes. Total crude oil production was essentially level with the previous year, as an increase in synthetic crude oil volumes balanced a small decline in conventional crude oil production. The major factor limiting conventional production was industry pro-rationing resulting from insufficient capacity in Canada's principal crude oil pipeline system.

Late in the year a supplementary sales program provided access to markets not subject to pipeline constraints, and completion of the first phase of a pipeline expansion program helped to reduce production cutbacks. Completion of the second phase of the expansion program in 1986 should further alleviate capacity limitations.

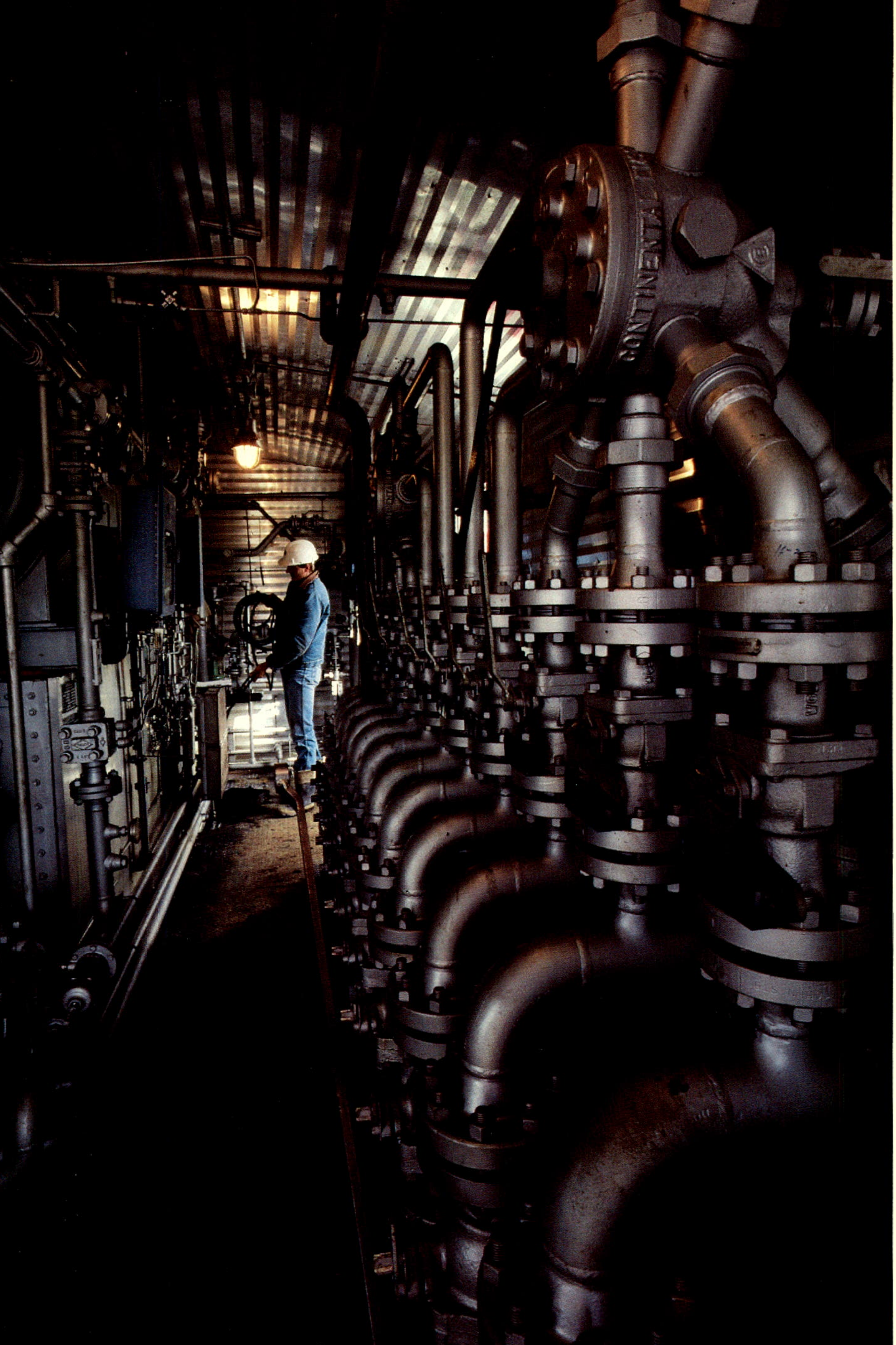
Production of field NGL increased 26 per cent to 17,100 barrels per day in 1985. This reflected the first full year's production from the West Pembina gas cycling plant, which came on stream in mid-1984.

Natural Gas - Production and Markets

Dome was one of the leading producers of natural gas in Canada in 1985. Our production averaged 591 million cubic feet per day, up seven per cent from 1984, and represented 7.6 per cent of total industry volumes. Because volume increases were offset by price declines, our net revenue from natural gas remained at the 1984 level.

The year 1985 was characterized by regulatory changes in Canada and by increasing price competition in the U.S. marketplace. The price paid for natural gas produced in Alberta and sold outside the province had been regulated since 1975.

Under a federal policy announced October 31, 1985, natural gas prices within Canada are being deregulated over a one-year period. As contracts expire, or by November, 1986, distributors and end users will become free to buy gas directly from producers at negotiated prices. Prices will probably fall as decontrol is introduced, because of Canada's large surplus supply of natural gas.



At Valhalla battery, oil from wells is gathered.

Gas deregulation brings uncertainty

In the past, almost all of the marketing of natural gas to Eastern Canada has been conducted by TransCanada PipeLines Limited. Dome, consistent with the industry average, has sold about half of its total natural gas production to TransCanada. Deregulation could result in a reduction of TransCanada's markets, which could force us to seek additional direct sales.

Regulations governing Canadian natural gas export sales have been adjusted in response to price declines in the U.S. marketplace. U.S. natural gas productive capacity is surplus to demand, which is causing extreme price competition. In November, 1984, provision for negotiated pricing for Canadian exported gas was introduced, with a minimum export price based on the price at Toronto. This permitted increased export sales. However, as U.S. prices continued to fall, Canadian gas again became uncompetitive.

Under the gas policy of October 31, 1985, export sales may now be negotiated at prices not less than the Canadian price at adjacent border points. Following this policy change, we were able to commence delivery of natural gas sold directly to U.S. customers under previously arranged contracts. From November, 1985 to February, 1986 we delivered up to 100 million cubic feet per day for ourselves and partners under these contracts. However, due to extreme price competition from fuel oil, sales under these contracts ceased by March, 1986.

Dome continues to conduct a strong natural gas sales effort, to at least maintain its share of the increasingly competitive market emerging from deregulation. We are well positioned to capitalize on our strong reserves base and underutilized production capability.

We expect that 1986 demand for Canadian natural gas will stay constant. Over the next two to five years, U.S. demand for Canadian natural gas is expected to grow substantially, providing opportunities for increased sales. Although 95 per cent of U.S. natural gas is supplied by domestic production, U.S. reserves and drilling activity have declined steadily over the past few years. As a result, deliverability is expected to decline, and we believe that Canadian natural gas will be needed to make up the shortfall.

Sulphur sales, prices are strong

Sulphur Sales

In 1985, Dome produced 1,181 long tons per day of sulphur, a 19 per cent increase from 1984. In total we marketed 1,723 long tons per day of sulphur, including our entire sulphur production, sales from inventory and some purchases from third parties. This represents approximately the same volume as in 1984. The average sales price in 1985 of $103 per long ton rose sharply over the 1984 price of $75 per long ton. Contracts are in place, at competitive prices, for the sale of all 1986 production as well as an additional part of accumulated inventory.

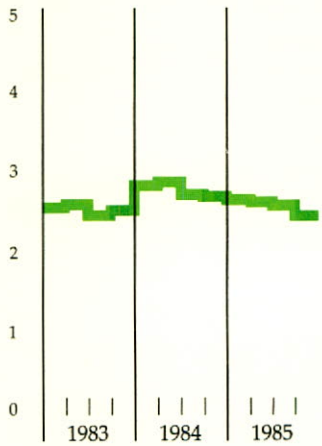
Large landholdings offer competitive advantage

Land

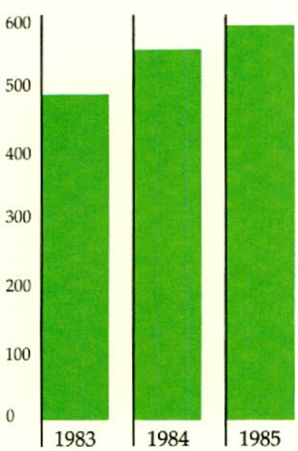
	Working Interest Gross	Working Interest Net	Royalty Interest
	(millions of acres)		
Western Canadian Provinces	22.8	10.0	1.2
Beaufort Sea	11.0	4.6	—
Other Frontier Lands	19.1	7.3	9.6
	52.9	21.9	10.8

Dome holds one of the largest spreads of oil and gas lands in Canada. With the wide geographical distribution of its Western Canadian holdings, Dome has interests in most of the major pro-

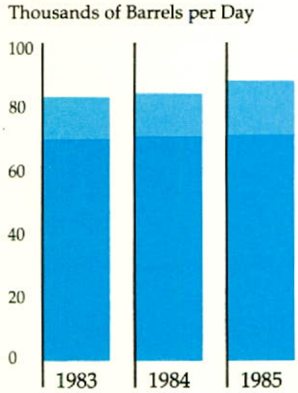
Natural Gas Prices
Canadian Dollars per MCF



Natural Gas Production
Millions of Cubic Feet per Day

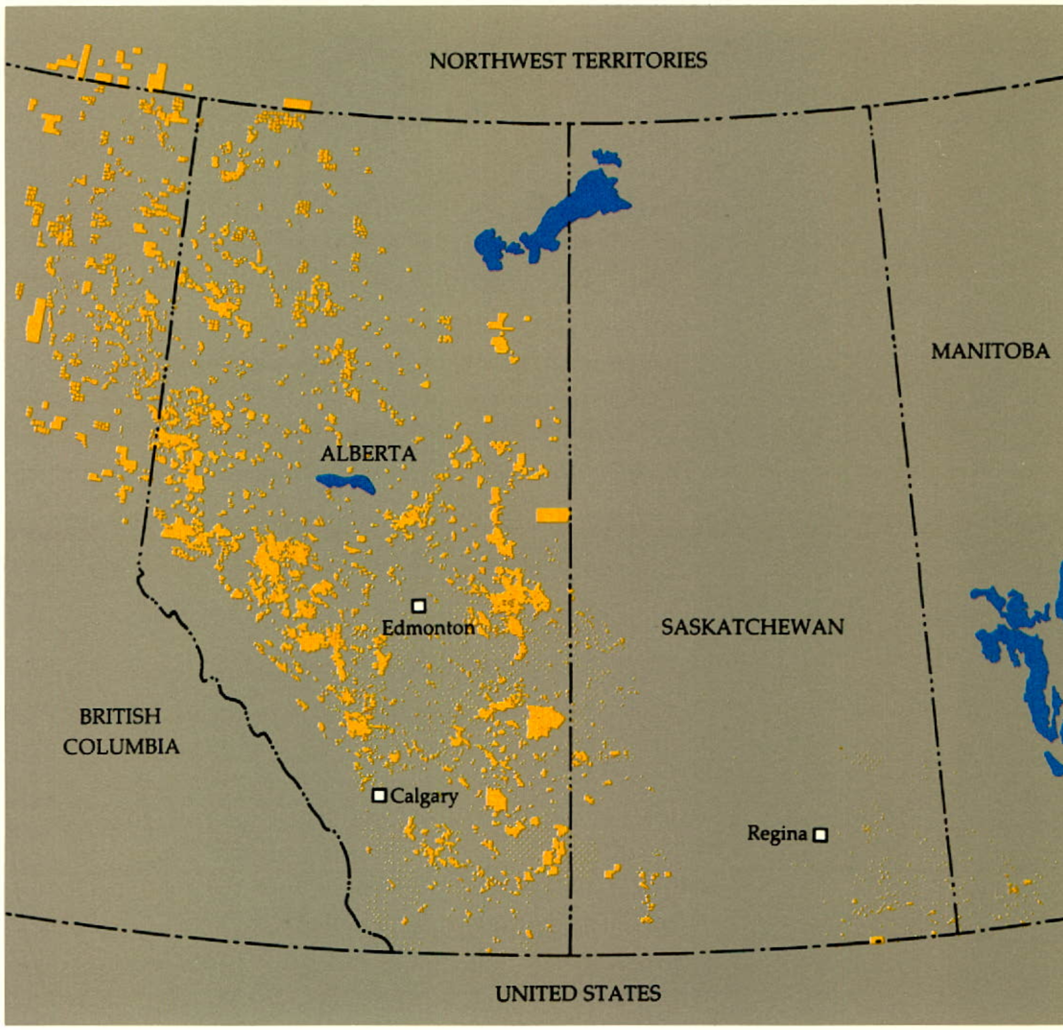


Crude Oil and Natural Gas Liquids Production
Thousands of Barrels per Day

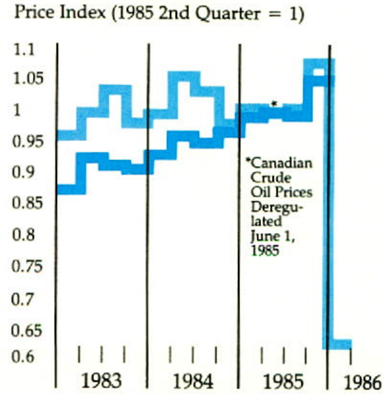


NGL
Crude Oil

Western Canada Land Holdings



Relative Change in Crude Oil Prices
Price Index (1985 2nd Quarter = 1)



West Texas Intermediate Spot
Dome Average

Oil price decline affects reserves

Crude oil is primary exploration target

Farmouts are key to vigorous exploration program

ducing fields and is well positioned to participate in exploration and development activity throughout the region. Of its total 21.9 million net acres, 2.6 million are developed and located in Western Canada.

Reserves

Dome's proved reserves at year end 1985, as evaluated by independent petroleum engineers, were as follows:

	Before Deduction of Provincial Royalties(1)	After Deduction of Provincial Royalties
Crude oil (millions of barrels)	203	175
Natural gas liquids (millions of barrels)	90	65
Natural gas (billions of cubic feet) (2)	4,377	3,483

(1) After deduction of freehold and overriding royalties

(2) Adjusted to a standard heat content of 1,000 British thermal units per cubic foot

At 1985 rates of production, Dome's reserves have life indices of nine years for crude oil, 14 years for field natural gas liquids and 20 years for natural gas.

Virtually all of the Company's reserves are located in Western Canada, primarily in Alberta.

Much, but not all of the effect of the recent decline in oil prices has been reflected in these reserve volumes. Certain reserves with high operating or development costs were removed from proved reserves because they would no longer be economic to produce at lower price levels. The reserve figures do not include Dome's interests in crude bitumen or discoveries in the Beaufort Sea and Arctic Islands.

Also excluded from the table above is Dome's interest in oil sands reserves at the Syncrude project in northeastern Alberta which produces synthetic crude oil. At year end, 1985, our share of proved reserves dedicated to the Syncrude project amounted to 55.2 million barrels of synthetic crude oil, before deduction of provincial royalties, but after freehold and overriding royalties.

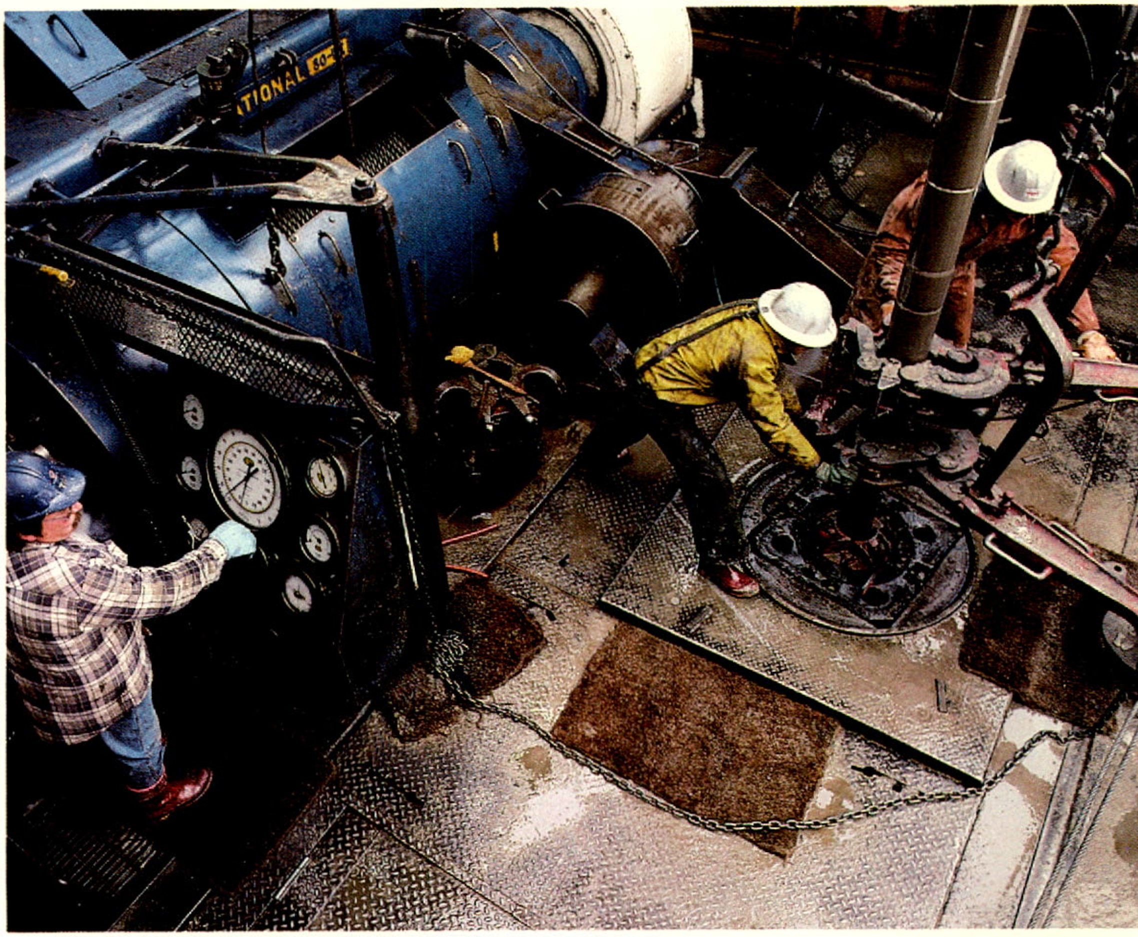
Exploration - Western Canada

Improved drilling economics resulting from fiscal changes fuelled increased activity on Dome's lands during 1985. However, with the sharp drop in crude oil prices early in 1986, and the March 31, 1986 expiry of the Petroleum Incentives Program, this activity will decline in 1986.

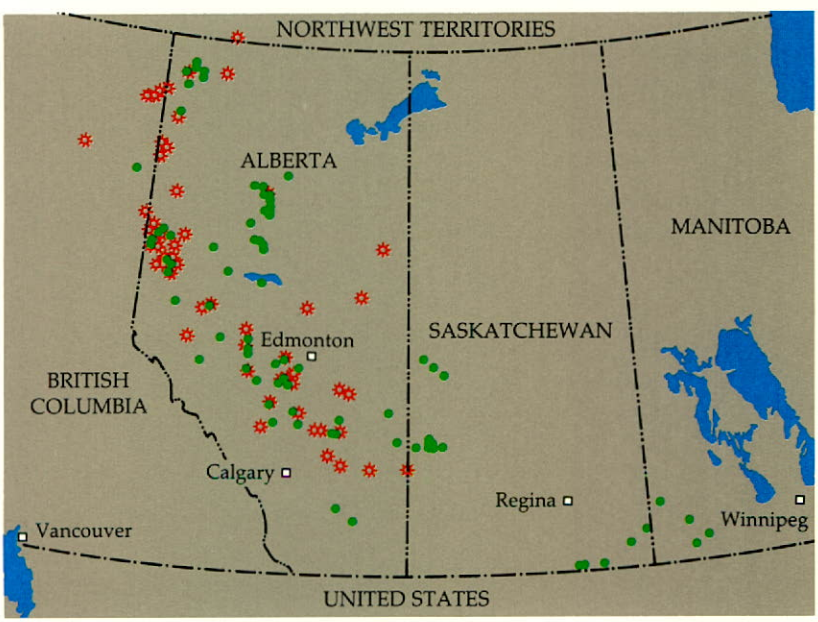
In order to achieve its objective of maximizing the value of its land, Dome has endeavored to discover and delineate as much economic conventional crude oil as possible. We have structured our drilling programs to explore the most promising prospects within the time constraints of land expiries. The Company's extensive land spread, large technical data base and experienced staff continue to identify numerous prospects.

Dome continues to fund its exploration program mainly through farmouts, which enable the Company to retain a portion of its expiring acreage, and to increase cash flow and reserves without capital investment. During the past five years, most of our exploration and much of our development activity has been carried out in this manner. Agreements with the two most significant participants, Dome Canada Limited and Home Oil Company Limited, run until July, 1986 and at least July, 1987, respectively. Discussions are under way between Dome Petroleum and Dome

Dome maintained an active exploration drilling program, funded mainly through farmouts.



Oil Well •
Gas Well ✲



1985 Exploration Drilling Areas

Canada to formulate a new agreement or to extend the existing arrangement. We expect that any significant exploration activity on our lands over the next several years will continue to be funded through farmouts.

In 1985, 277 gross exploratory wells were drilled on Dome Petroleum's lands of which 134 wells were drilled under farmout to Dome Canada and Home Oil, 111 wells were drilled under other farmout arrangements and 32 wells were drilled directly by Dome. Seventy-five per cent of Dome's exploratory wells were drilled in Alberta in 1985.

Beaufort Sea

Dome's main area of activity on Frontier lands has been the Beaufort Sea. Since 1976, Dome has drilled 26 wells, directly or through farmout, of which 11 were oil wells, four were gas wells and 11 were dry holes.

During 1985, a significant discovery was made at Adlartok P-09. Oil flowed from four intervals at a combined rate of 4,132 barrels per day. Delineation drilling will be required to define the extent of reserves and their potential for development. Dome holds a 20.9 per cent interest in this well.

Development activity in Western Canada accelerates in 1985

Other exploratory activity in the Beaufort Sea in 1985 included drilling and testing of two wells carried over from the 1984 drilling season, Arluk E-90 and East Nerlerk J-67. Both wells were dry and abandoned. A wildcat well spudded in 1985, Edlok N-56, was abandoned without testing. Testing of Havik B-41 was not completed in 1985 due to ice problems. The Company does not have a direct interest in this well, but has an indirect interest through Dome Canada and holds an approximate 31 per cent interest in adjoining acreage.

At year-end, we held 11.0 million gross acres (4.6 million net acres) in the Beaufort Sea.

Our exploration agreements with the Canadian government along with additional contractual drilling commitments required the Company to drill a number of wildcat wells in order to earn and retain its lands in the area. These wells have been completed with the exception of the testing of Havik B-41.

Other Frontier Lands

The Company also has land interests in the Mackenzie Valley in the Northwest Territories, the Arctic Islands and in the offshore areas of the East Coast of Canada.

In 1985, drilling activity in the Mackenzie Valley included eight wells which resulted in three oil wells, one gas well and one suspended well, some of which were not completed until early 1986.

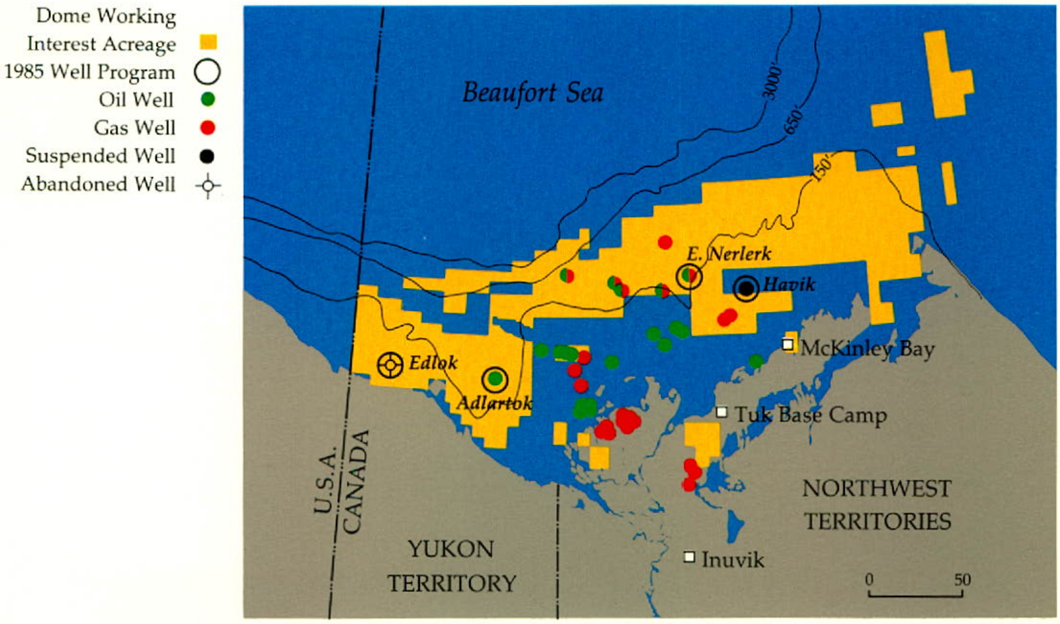
Two wells drilled on Dome's lands in the Arctic Islands resulted in one gas well, Drake L-06, which flowed 26 million cubic feet per day under test. The Company's interest in this well and the surrounding acreage is approximately 38 per cent.

Development - Western Canada

In 1985, Dome spent $96 million on development of its crude oil and natural gas reserves. Additionally, a substantial amount of development drilling on Dome's lands was funded by farmout to Dome Canada and others. We participated, directly or through farmout, in a record 1,233 development wells, 69 per cent of which were in Alberta.

The major target of our development activity during 1985 was crude oil, because it offered ready markets and

In the Beaufort Sea, Adlartok P-09 was a significant oil discovery.



Beaufort Sea Area

better economic returns than natural gas. We limited our development of natural gas prospects to those offering immediate production and sales. We have a large portfolio of development prospects and assign available funds to those calculated to provide the fastest payout and highest rates of return. As a result of the severe reductions in oil prices during the early part of 1986, we expect that capital expenditures for development activity on our lands will be significantly reduced for the remainder of the year.

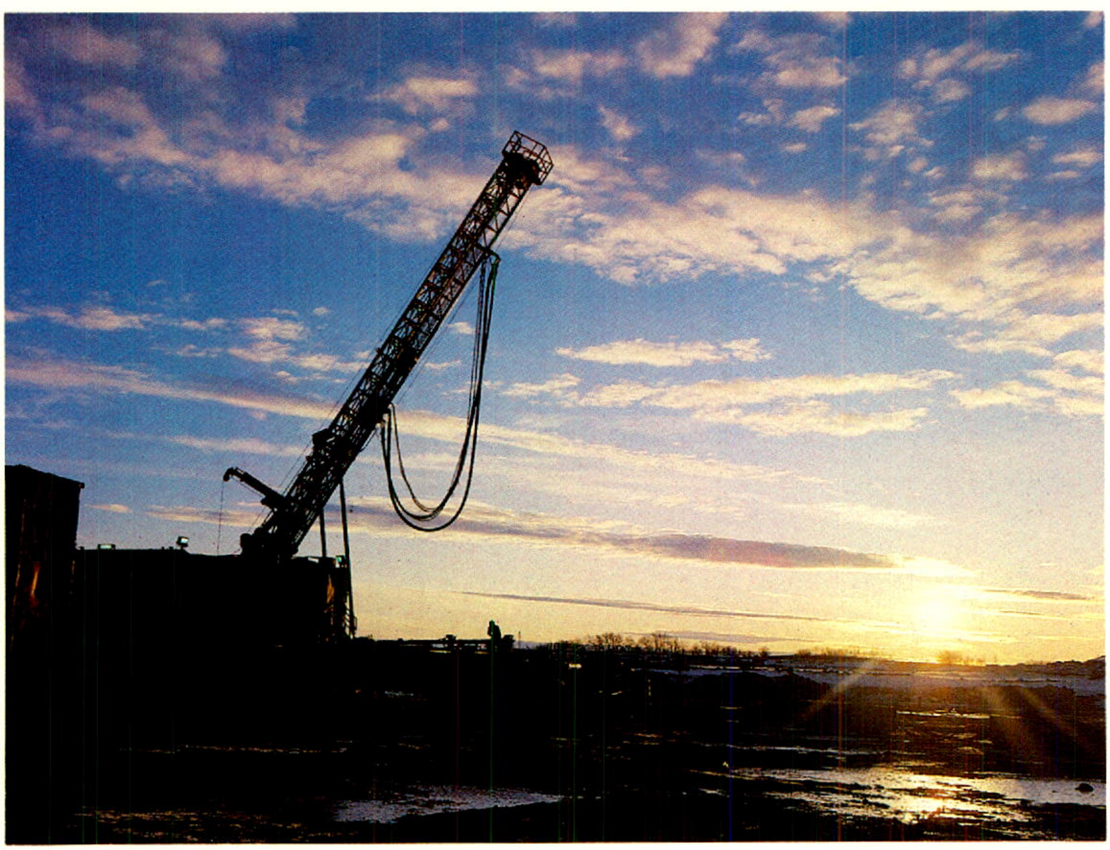
Low prices delay heavy oil projects

Two major projects which Dome had underway and which are now on hold are our 15,000 barrel per day enhanced heavy oil recovery project at Lindbergh, near Lloydminster, in east-central Alberta and our 25,000 barrel per day oil sands project at Primrose in the Cold Lake region of Alberta. The pace of development at Lindbergh and the start up of commercial production at Primrose will depend primarily on the level of oil prices, since enhanced oil recovery costs are substantially higher than costs for primary methods of recovery.

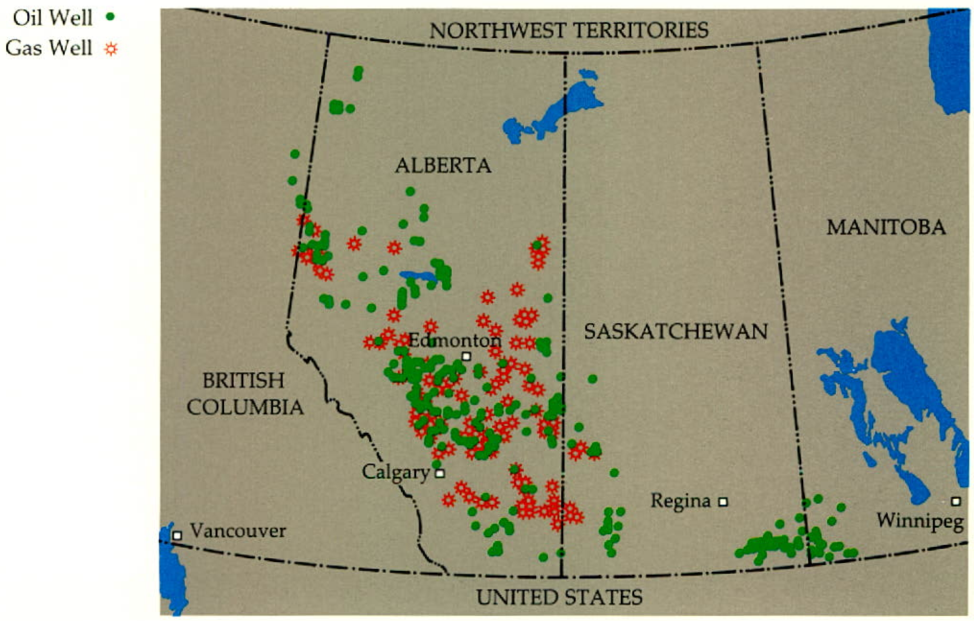
In June, 1985, Dome reduced its interests in the Primrose area through the sale of its rights to earn an interest in 48 sections of the original 360 section block for $79 million.

At Wembley, Alberta, a gas cycling project which is expected to produce an average 2,400 barrels per day of natural gas liquids net to Dome, commenced production April 1, 1986.

The number of development wells drilled in 1985 set a Dome record.



In Lindbergh heavy oil field, oil pumps are assembled on a central "pad". Because of slant-hole drilling, wells are some distance from the pad.



1985 Development Drilling Areas

Natural Gas Liquids Operations

In 1985, we maintained our role as the leading marketer and producer of NGL in Canada, and as a major marketer in North America.

NGL operating income increases

Cash operating income from this business segment in 1985 was up 17 per cent from the previous year, and represents 17 per cent of the corporate total.

The Company's NGL operations are based upon two integrated systems, the NGL System and the Alberta Ethane Gathering/Cochin Pipeline System. These systems comprise a network of liquids extraction plants, storage facilities, fractionation plants, and pipeline and distribution facilities. The NGL facilities are sufficiently developed that operations can be maintained with a relatively low level of capital expenditures. In 1985, $18 million was spent on capital expenditures for this business segment.

Integrated network provides competitive edge

Our NGL facilities built up through years of investment enable us to transport, process, store and market NGL very competitively. Because of the size and diversity of the network, we can deliver and exchange products to different geographic markets on relatively short notice, and direct NGL to those areas in which the best prices can be obtained.

Propane, butane bolster sales volumes

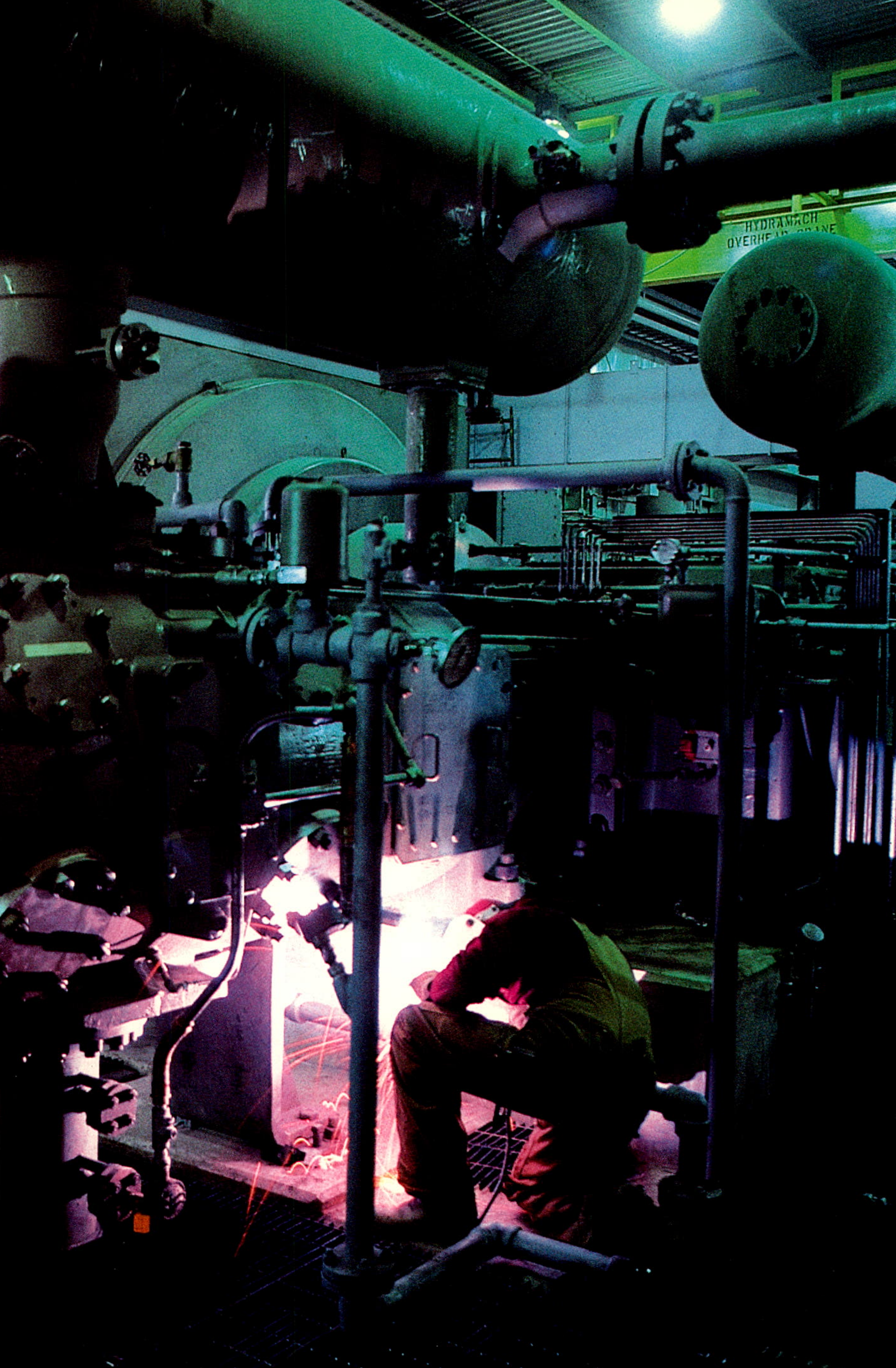
In 1985, higher propane and butane volumes more than offset volume declines of other products. Propane and butane volumes increased by 33 per cent and 25 per cent respectively over the previous year. These improvements were due to higher sales of natural gas, from which these products are obtained, and from inventory drawdowns.

The modification of our fractionation facilities at Fort Saskatchewan, Alberta, completed in March 1986, enables us to produce additional pentanes plus. This change increases our marketing flexibility in Western Canada.

Ethane sales volumes were 16 per cent lower than in 1984 due to reduced purchases by Columbia LNG Corporation. Columbia has been a major purchaser of ethane for use in manufacturing synthetic natural gas. However, the volumes Columbia has taken over the last three years have been declining, and at the end of March, 1986, our contract expired. Ethane markets to partially replace the lost Columbia market have been developed in Eastern Canada. In addition, we are selling ethane to enhanced oil recovery projects in Alberta.

Propane prices declined seven per cent on average in 1985. Butane prices also dropped, by about two per cent. Prices of pentanes plus, similar to a high quality crude oil, rose nearly 10 per cent following the mid-year deregulation of crude oil.

In 1985, about 34 per cent of our NGL supply was extracted from natural gas streams at straddle plants. The price paid for this NGL is related to the price of natural gas at the Alberta border. Under current legislation, the price of natural gas is scheduled to remain at its current level until November 1, 1986, when it will be deregulated.



Welder installs new equipment at the Edmonton ethane extraction plant. Expansion was needed to process feedstock from new sources.

World crude oil prices affect NGL prices

We are negotiating with Interprovincial Pipeline Limited (IPL) regarding the lease of spare capacity in the Cochin Pipeline to transport NGL. IPL owns and operates Canada's main trunkline system carrying crude oil and NGL from Western Canada to Eastern Canadian and U.S. Midwest markets. IPL's expansion programs have not been able to keep pace with a rapid growth in demand for shipping capacity in the trunkline system, which has resulted in significant cutbacks in production of crude oil. Dome has proposed a short term lease to September, 1987, which would provide IPL with 25,000 barrels per day of Cochin capacity, and the option to acquire an ownership interest in Cochin equivalent to the same capacity.

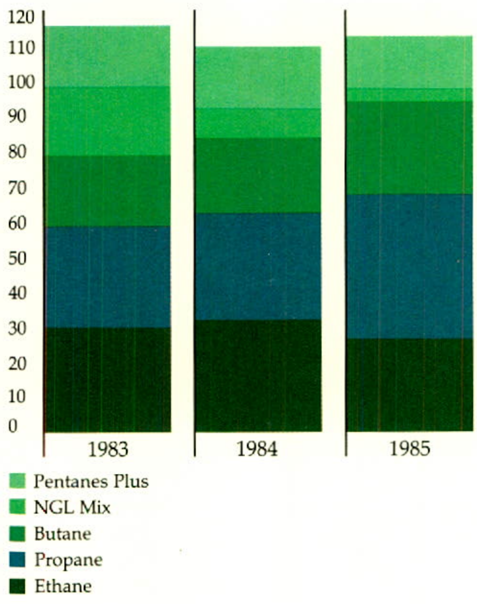
Dome owns and operates the Rangeland Pipeline System, a crude oil and NGL trunk line system extending from Rimbey in central Alberta to the Alberta-Montana border. In late 1985, Rangeland modified its facility to allow shipping of heavy crude oil from Esso Resources Canada Limited's Cold Lake project to its Billings, Montana refinery.

On July 1, 1985, we sold the Producers/Westspur Pipeline, a crude oil gathering and trunkline system located in southeastern Saskatchewan, for $26 million.

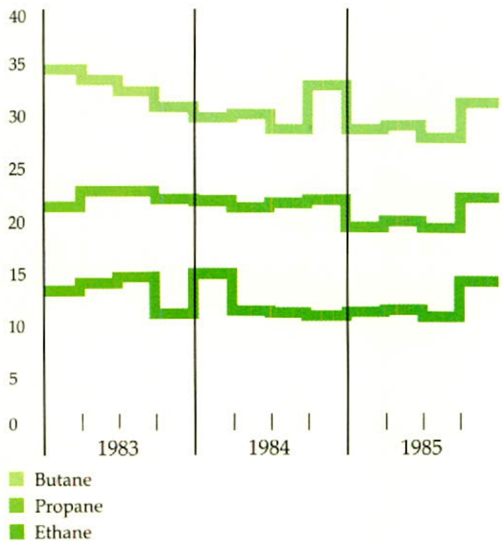
Outlook

The steep decline in world crude oil prices also affects NGL prices. We anticipate that 1986 operating income from this segment will be lower than that of 1985.

Natural Gas Liquids Sales
Thousands of Barrels per Day

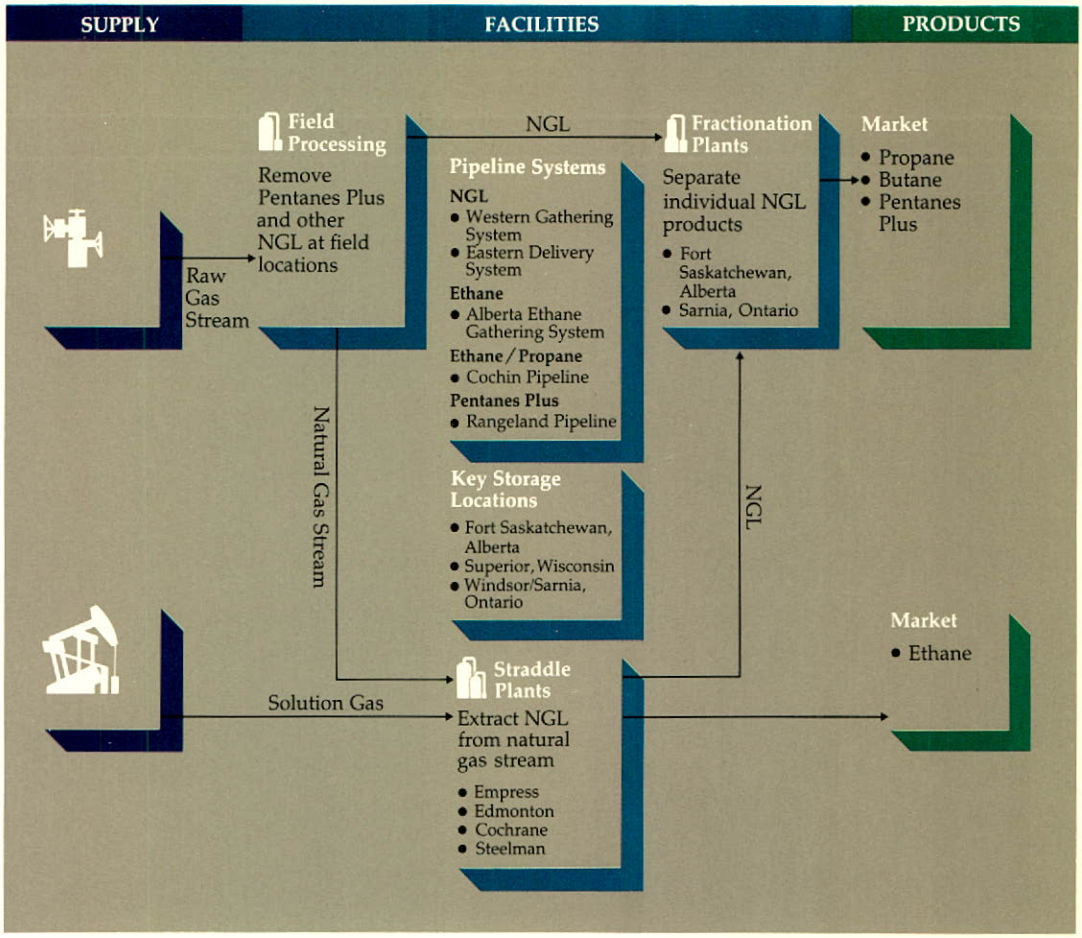


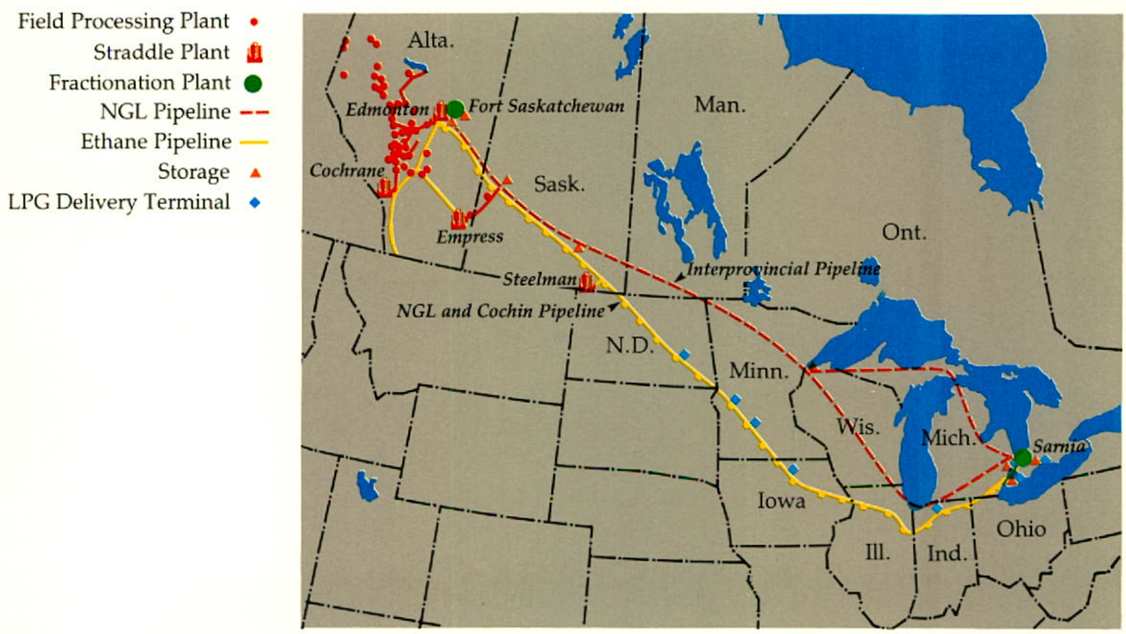
Natural Gas Liquids Prices
Canadian Dollars per Barrel



Natural Gas Liquids

Business Overview





Alberta Ethane Gathering System and Cochin Pipeline

Contract Drilling Operations

Largest fleet of Beaufort Sea drilling systems

Dome owns the largest fleet of offshore drilling systems capable of operating in the Beaufort Sea environment. The five drilling systems, supported by numerous other vessels, are operated under the trade name Canmar. In 1985, this business segment generated 12 per cent of the Company's total cash operating income.

During the 1985 summer drilling season, all four of Canmar's drillships were active, with three systems operating in the Canadian Beaufort Sea and one in the U.S. Beaufort Sea. The bottom-founded drilling system, the SSDC, was idle throughout the year.

Although the three drillships operating in the Canadian Beaufort Sea had to contend with severe ice conditions, Canmar drilled and evaluated two wells and completed testing at one of those wells. Testing was also completed at a third well which had been drilled in 1984. At a fourth location, ice conditions prevented the completion of testing.

The northern offshore operations safety award of the Canadian Association of Oilwell Drilling Contractors was won for the second consecutive year by Canmar. This year the successful recipient was Canmar's Explorer IV drillship which completed its 1985 drilling season accident free.

First U.S. drilling contract is completed

A milestone of the season's activity was the successful completion of the first drillship contract in the U.S. sector of the Beaufort Sea by the joint venture between Canmar and Reading & Bates Drilling Co., a U.S.-based drilling contractor. Explorer II, by drilling and evaluating the Hammerhead well in one season, established that drillships can work effectively in the U.S. Beaufort Sea. This opened up a new market area for Canmar and now provides U.S. oil companies an alternative for evaluating leases in water too deep for the economical construction of gravel islands. Canmar is making a strong marketing effort to diversify its area of operations to include both the Canadian and U.S. regions of the Beaufort Sea.

The joint venture has secured additional contracts in the U.S. Beaufort Sea. One drillship has been contracted for the 1986 drilling season,

Massive MAT for SSDC

The SSDC/MAT is the latest of Canmar's technological innovations for drilling in water depths of 30 to 75 feet, which is normally too shallow for floating drill systems. In 1982, Canmar developed the first mobile bottom-founded drilling system, the SSDC, which has to date required the dredging of an undersea island for support. The steel MAT will replace the expensive berm, allowing more rapid and efficient drilling.

The MAT, pictured at right, has been constructed in Japan. It weighs 35,000 tons and measures 360 feet wide by 550 feet long by 50 feet deep. The MAT will be towed across the Pacific Ocean during the summer of 1986 and joined with the SSDC in Alaska.

The SSDC/MAT will be state of the art technology in Arctic drill systems. Its design, with a very large footprint and large mass, enables it to withstand multi-year ice forces in the Beaufort Sea during all seasons of the year. The SSDC/MAT has been contracted to Tenneco Oil Company and Sohio Alaska Petroleum Company for two years commencing in the fall of 1986 to drill offshore Alaska in the U.S. Beaufort Sea.

The MAT, at completion of construction at Hitachi Zosen Shipyard in Japan.

Exploration success extends known potential

New Frontier policy offers equal rewards to foreign firms

and the SSDC/MAT has been contracted for the two years commencing in the fall of 1986.

Canmar expects to return to the Canadian Beaufort Sea in 1986 to complete the testing of the Havik well. It is also pursuing further marketing opportunities in both the U.S. and Canadian areas of the Beaufort Sea.

The utilization of Canmar's drilling systems depends on a variety of factors, most importantly the level of exploratory success in the Beaufort Sea and the outlook for world oil prices.

The exploratory success of Dome's Adlartok oil discovery and Gulf Oil Corporation's Amauligak delineation oil well, both in the Canadian Beaufort Sea, extended the known geological potential of the region. According to announcements by Gulf, its well, which tested at cumulative rates in excess of 30,000 barrels per day, indicates that the Amauligak oil field has the necessary threshold reserves to become the lead production project needed to justify an oil transportation system to bring Beaufort Sea oil fields on production in the 1990's. The commerciality of oil production from the Beaufort Sea does, however, depend on a recovery of oil prices from current levels.

During 1985, changes to Frontier energy policy were announced which include the elimination of government grants and the removal of the government's right to "back in" on 25 per cent of an exploratory success. This will raise the cost of drilling for our traditional partners, Dome Canada and Home Oil. However, drilling may be more attractive for foreign-owned companies, for which the cost of drilling remains the same, but the reward for success is significantly improved.

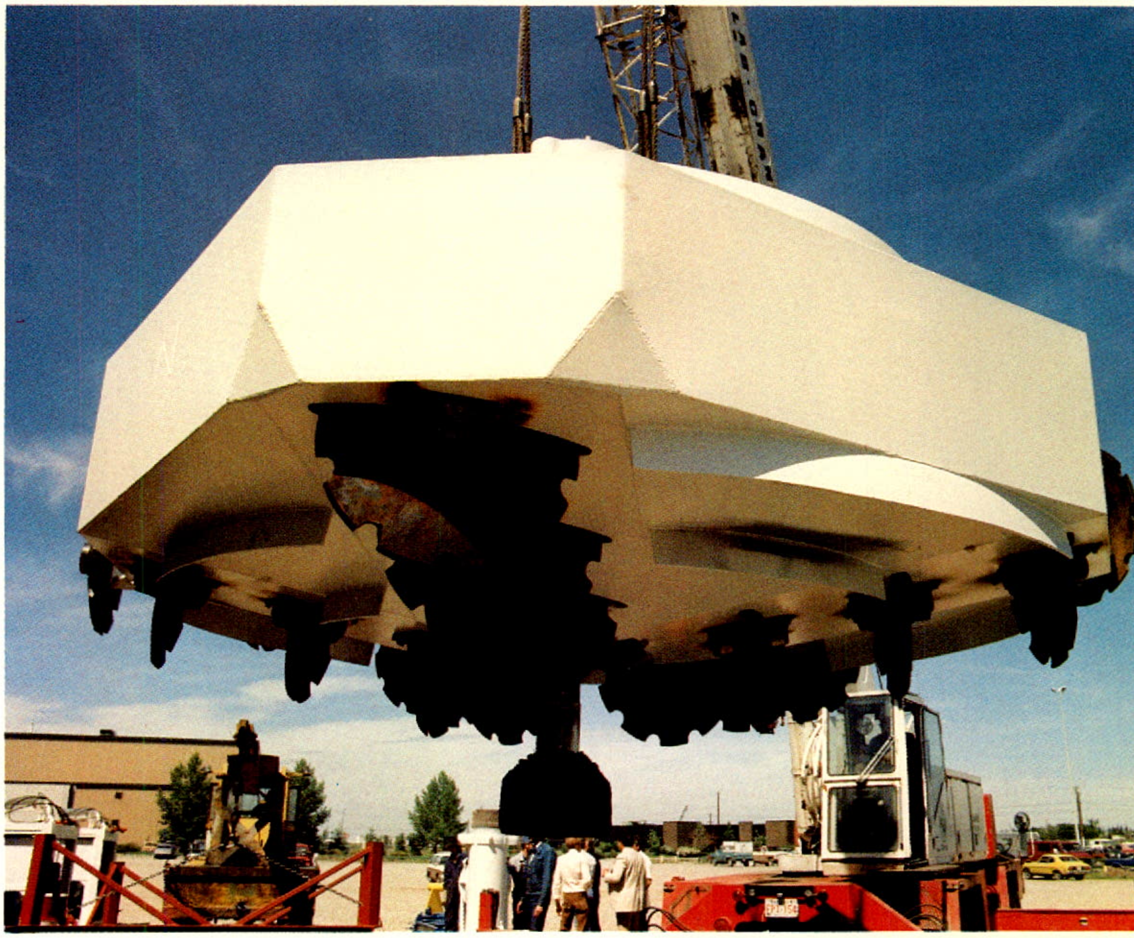
Big Bit Speeds Excavation

One of the first tasks when moving onto an offshore drilling location is to ensure that the well is established safely. In the Beaufort Sea, subsea wellheads and blowout preventor stacks cannot be exposed to the risk of damage from the moving ice pack. It is therefore necessary to excavate a cavity in the sea floor, better known as a glory-hole, large enough to accommodate the 14 foot diameter blowout preventor stack and deep enough to avoid the risk of damage due to ice scouring.

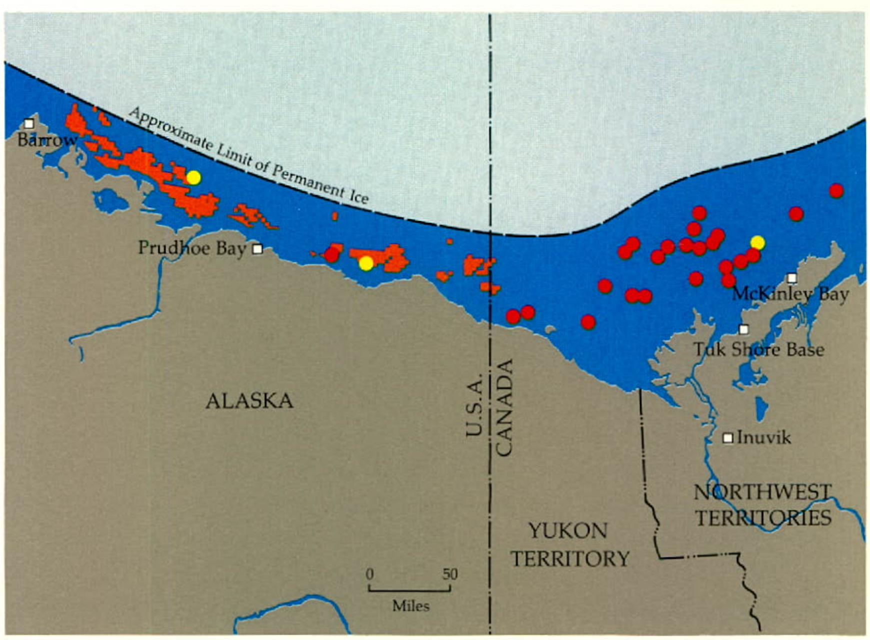
When Canmar began offshore drilling operations in the Beaufort Sea in 1976, no equipment existed for the efficient excavation of glory-holes. Early glory-hole operations took about two weeks, which was very costly. In 1978 Canmar developed the technology to reduce glory-hole excavation to one week by designing and constructing a 17 foot drillbit.

In 1985, modifications to the 17 foot bit and construction of a new improved 20 foot glory-hole bit pictured here have given Canmar the leading edge in this technology. The new bit was used by the Explorer IV at the Edlok N-56 location in 1985 and allowed Canmar to complete the 36 foot deep glory-hole in less than two days. The original 17 foot bit is with the Explorer II drillship offshore Alaska where it has been used successfully to complete three glory-holes for U.S. operators in 1984 and 1985.

Unique bits give Canmar an advantage in drilling "Glory Holes" on the floor of the Beaufort Sea.

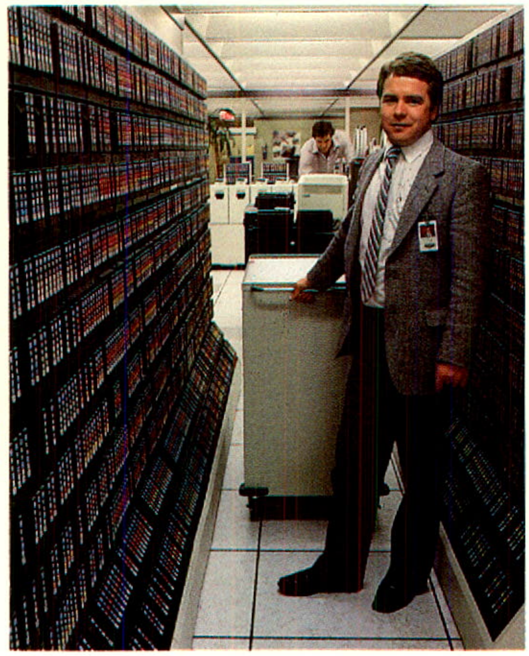


1986 Planned Drillsite
Canmar Wells Drilled
U.S. Offshore Leases



Contract Drilling — U.S./Canadian Beaufort Sea

Operating Efficiency: An Endless Quest



Day by day, Dome employees at all levels find new ways of saving money and increasing productivity.

Fred Plummer, instrument technician at Dome's Valhalla oilfield, had a number of ideas about how to improve record keeping. Shown seated in the photo with battery operator Ron Hartman, Fred put together a program on his home computer which his superiors encouraged him to develop further on the job.

The result was greatly reduced paperwork for battery operators, and better quality data for their daily operating decisions. Use of the program has helped the operators achieve maximum oil production levels within government regulations.

John Eddy, manager, information services operations, and his team of specialists recently met an imposing challenge: to complete the transfer of an entire mainframe production system to an outside computer service bureau in record time, while maintaining good service to the 1,850 employee computer users on the network.

This type of transfer usually requires four to six months, and is often plagued by major disruptions which can cripple normal operations. John and his team completed the task in four weeks flat, and without a hitch. The operation was part of a major project to merge two incompatible computer systems into one. This system merger, together with other improvements, saved Dome $1.1 million in 1985 alone.

High volume jet pumps extract much more oil faster from oil wells at Dome's Sturgeon Lake field in Alberta than would be possible with conventional equipment. Field engineer Jim Grond ordered them to handle the greatly increased production that he and others had achieved in this declining field in 1985 through workover of wells.

Field employees, led by production superintendent George Soroff (l.) and production foreman Joe Roberge, working with engineering staff, installed the pumps. They had also supervised a program of expanding surface facilities which, when coupled with the well workover program, yielded a 25 per cent increase in Sturgeon Lake oil production.

When responsible for developing new crude oil and condensate markets, Ian Richardson (in photo) had a money-making idea.

NGL pipelined from Alberta to Dome's Sarnia plant was buffered at each end with more expensive Syncrude synthetic oil, to avoid contamination with other material. The Syncrude product was processed with the NGL. Ian's idea was to retrieve this oil and sell it at a premium price.

Project manager Vic Humeniuk, working with used components for speed and economy, quickly turned the idea into reality. Ian, now eastern area superintendent for the NGL group, reports substantial additional revenue for 1985 as a result.

When produced, heavy oil is thick like molasses. It's also contaminated, largely with water and sand. Treatment chemicals and condensate must be used to purify it and thin it to pipeline specifications. Both are expensive, and if less of one is used, more of the other is necessary.

Gilbert Shantz, Lindbergh battery foreman, and his production crew wouldn't accept conventional wisdom. Over a period of months they found ways to reduce the use of both chemicals and condensate, for a 1985 saving of $800,000.

Not satisfied with that, they also treated Dome's oil from all surrounding areas, which previously had been trucked elsewhere. While increasing the Lindbergh throughput by 27 per cent, they saved Dome another $1 million in trucking costs for the year.

Associated Companies

Dome Mines Limited

Dome Petroleum is the principal shareholder of Dome Mines. In January, 1986, Dome Petroleum sold 10 million of its 30.9 million shares in Dome Mines, reducing its ownership from 34.4 per cent to 23.2 per cent. Dome Mines is also the principal shareholder of Dome Petroleum and owns directly and indirectly 22.0 per cent of its common shares.

Dome Mines and its operating subsidiaries, Campbell Red Lake Mines Limited and Sigma Mines (Quebec) Limited are principally in the business of the mining and milling of gold bearing ore to produce gold bullion, and in 1985 produced 466,300 ounces of gold. Dome Mines owns 56.9 per cent of the common shares of Campbell and 64.7 per cent of the common shares of Sigma. Operations are conducted by Dome Mines at South Porcupine, Ontario, by Campbell at Balmertown, Ontario and in the Detour Lake area of Ontario and by Sigma at Val d'Or, Quebec.

For its fiscal year ended December 31, 1985, Dome Mines reported revenue of $261 million and net income of $12 million.

In May, 1985, Dome Mines acquired 52.9 per cent of McIntyre Mines Limited (which owned 22.1 per cent of Falconbridge Limited) and 7.8 per cent of Falconbridge for $160 million.

Dome Canada Limited

Dome Petroleum owns 48 per cent of the common shares of Dome Canada, with the remainder held by Canadian investors. Dome Canada has carried out a significant portion of the exploration on Dome Petroleum lands. The Dome Exploratory Lands Agreement (DELA) provides for the management of Dome Canada's oil and gas operations by Dome Petroleum, and Dome Canada's administrative functions are also performed by Dome Petroleum. The DELA is scheduled to terminate in July 1986. Discussions are underway between Dome Petroleum and Dome Canada to formulate a new agreement or to extend the existing agreement by that date.

In 1985, Dome Canada's average daily production was 9,800 barrels of oil, 61 million cubic feet of natural gas and 2,600 barrels of NGL. Dome Canada's 1985 net income was $35 million, up nine per cent from 1984. Funds generated from operations totalled $160 million, an increase of 19 per cent from 1984. Exploration and development expenditures net of PIP grants totalled $200 million.

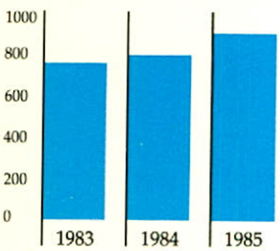
Financial Review

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

This discussion of results of operations and financial condition should be read in conjunction with the consolidated financial statements and notes which follow the discussion. The financial statements and notes are dated March 27, 1986, but this discussion incorporates changes in the Company's situation subsequent to that date.

Summary

Total Operating Income
Millions of Canadian Dollars



During the past several years, the Company has been working to resolve its financial problems which arose as a result of a combination of events. The Company had completed a series of major acquisitions largely financed by bank borrowings, revenues were lower than expected and interest rates had increased significantly. In 1982, a large portion of the debt was currently due resulting in a severe cash flow shortfall. The Company's strategy was to attack its problems on a number of fronts. By agreement with the Company's lenders, a large part of long term debt was rescheduled over the period to 1995. The Company reduced discretionary expenditures wherever possible. General and administrative expenses have been cut by 44% over the past three years. Capital expenditures have been trimmed considerably and the Company has relied on an extensive farmout program to explore and develop its oil and gas asset base. Cash has been raised through the sale of non-essential assets and a successful equity issue in 1985.

These measures resulted in a steady improvement in the Company's financial position. At the end of 1985, cash on deposit was $466 million and working capital was positive at $178 million.

The Company also experienced an improvement in its operating results. Revenues were maintained over the three year period, but operating expenses have been trimmed resulting in improved operating income. Corporate expenses declined sharply in 1985 over 1984 as a result of much lower interest costs and a substantial reduction in the foreign exchange loss charged to the statement of operations.

The combination of improved operating income and lower corporate expenses resulted in net income of $7 million in 1985, after an extraordinary item, compared with net losses of $197 million in 1984 and $1,105 million in 1983. The 1983 loss included a write-down of assets of $897 million net of deferred income taxes.

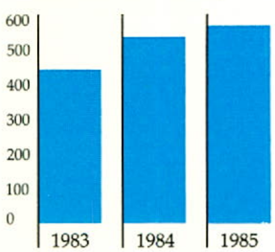
The Company's financial statements are prepared in accordance with Canadian accounting principles. Had they been prepared in accordance with U.S. accounting principles, the Company would have reported a net loss of $167 million in 1985 principally due to the difference in accounting treatment of foreign exchange. See Note 21 to the consolidated financial statements for a discussion of the differences in accounting principles and the effect of recent oil price declines on the carrying value of the Company's oil and gas properties on a U.S. basis.

The Company's future financial position is sensitive to a number of factors beyond its control, the most important being oil prices and interest rates. A continuation of the substantial decline in the international price of oil in early 1986 will severely reduce the Company's revenues and cash flow. In order to avoid a significant reduction in liquidity, the Company has approached its affected lenders with an interim plan. A further discussion of factors upon which the Company's future financial position, results of operations and continued existence as a going concern are dependent and its plan to avoid a significant reduction in liquidity is contained in the Outlook section of the Financial Condition discussion and in Notes 2, 8 and 22 to the consolidated financial statements.

Results of Operations

Crude Oil and Natural Gas

Crude Oil and Natural Gas Operating Income
Millions of Canadian Dollars



In 1985 both revenue and operating income from crude oil and natural gas increased over 1984 and 1983 levels. This increase was mainly a result of higher prices for oil, and increased natural gas liquids revenue from field operations.

Average oil prices received by the Company were $34 in 1985, $32 in 1984 and $31 in 1983. Canadian oil prices were deregulated in June of 1985 and the average oil price received by the Company rose in the second half of the year as a result. In 1984, when oil prices were regulated, a higher proportion of the Company's production qualified for world price than in the previous year. Revenue from field natural gas liquids increased in both 1985 and 1984 due primarily to sales from the new West Pembina plant, which started production in mid-1984, and higher natural gas production volumes. The benefits from increased natural gas production in 1985 and 1984 were largely offset by lower export prices in both years.

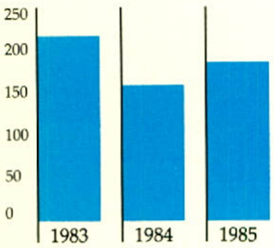
Operating expenses increased 15% in 1985 over 1984 partly reflecting the increase in production of oil, field natural gas liquids and natural gas. The remaining part of the increase is largely due to increased workovers and enhanced oil recovery expenditures.

Prices have declined sharply in the international oil market since the beginning of 1986. If lower oil prices persist, revenues and operating income will be significantly reduced. See Outlook section of Financial Condition discussion.

In October 1985, the governments of Canada and the three major producing provinces agreed to deregulate natural gas prices over a one year period. For domestic sales during the transition period, the price for existing contracts is generally fixed. On the earlier of contract expiry or November 1, 1986, the price will be determined by negotiation. It is expected that domestic prices will decline as a result of deregulation, as Canada has a large surplus of natural gas and also as a result of the decline in oil prices. For export sales, negotiated pricing became effective on November 1, 1985 at prices equal to or above the Canadian price at adjacent border points. The Company expects 1986 sales volumes of natural gas to the export market to increase, but at lower prices than in 1985. In the longer term, as U.S. gas deliverability declines, a market for Canadian natural gas can be expected to develop which will, however, be subject to government export approvals.

Natural Gas Liquids

Natural Gas Liquids Operating Income
Millions of Canadian Dollars

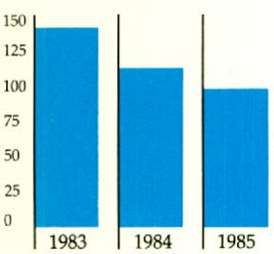


Operating income from NGL operations was $187 million in 1985, an increase of 18% over operating income in 1984 of $159 million. This improvement was mainly due to greater margins for propane and butane, especially in the fourth quarter when there was a sharp upward price movement which followed crude oil price increases. There is also a small improvement in 1985 operating income as compared to 1983, after deducting a one-time payment in 1983 of $36 million from Columbia LNG Corporation for contractual volumes not taken.

The sharp decline in world crude oil prices in early 1986 is affecting NGL prices. If the decline persists through 1986, the Company expects that 1986 results will be significantly lower than in 1985.

Contract Drilling

Contract Drilling Operating Income
Millions of Canadian Dollars



The Company's contract drilling revenue and operating income have declined over the three year period to December 1985. This principally reflects the fact that one of the Company's five drilling systems, the SSDC, was fully utilized in 1983, only partially in 1984 and was not contracted at all for 1985. All four drillships were fully utilized in each of the three years.

Prior to 1985, the Company's contract drilling activities were conducted primarily in the Canadian Beaufort Sea. During 1985, the Company successfully completed its first drilling contract in the U.S. Beaufort Sea. A contract for 1986 for the same drillship has been signed and in addition the SSDC has been contracted for two years from September 1986, both contracts being in the U.S. Beaufort Sea. These three contracts are the result of a strong marketing effort in a joint venture with Reading & Bates Drilling Company to extend the Company's contract drilling market to include the U.S. segment of the Beaufort Sea.

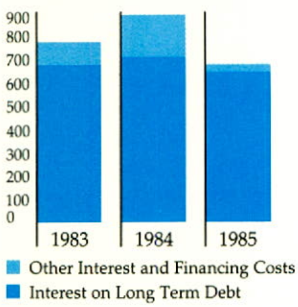
In addition to the two drilling contracts in the U.S. Beaufort Sea in 1986, the Company plans to return to test a well in the Canadian Beaufort Sea, Havik B-41, that was not completed in 1985. Efforts are also continuing to secure further contracts for the Company's remaining two drillships for the 1986 drilling season.

In 1985 the Canadian government proposed changes which will affect the economics of offshore exploration in frontier areas. The level of government funding will be reduced with the elimination of Petroleum Incentives Program (PIP) grants which will be replaced with a system of income tax credits. In addition, the government proposes to eliminate the 25% "back-in" on frontier lands. For those companies that received the minimum level of PIP grants, the economics of exploration may actually improve. However, for those companies that received higher levels of grants, the cost of drilling will increase. Dome Canada, the Company's largest customer for contract drilling services in the Beaufort Sea since 1981, qualifies for a high level of PIP grants. The proposed changes will significantly increase the cost of drilling for Dome Canada. It is expected that Dome Canada will substantially reduce its level of expenditures in the Beaufort Sea area.

It is difficult to predict the impact of the proposed changes on activity in the Canadian Beaufort Sea, although combined with the recent decline in oil prices, it is likely to be negative in the short term. Exploration successes, together with a recovery in oil prices which the Company expects in the longer term, may result in improved future prospects. In 1985, exploration successes included Dome Petroleum's oil well at Adlartok P-09, and a highly successful delineation well by Gulf Canada Corporation at its Amauligak oil field.

Corporate Expenses

Interest and Financing Cost Before Capitalized Interest
Millions of Canadian Dollars



Corporate expenses in 1985 declined substantially over 1984 largely due to lower interest rates and the reduced impact of foreign exchange fluctuations on income.

Interest and financing costs before capitalized interest totalled $678 million in 1985, a substantial decline from 1984 and 1983 levels of $891 million and $784 million respectively. The decline in 1985 was primarily due to a drop in interest rates and the absence of interest on unpaid income taxes which were deferred as a result of remission orders granted by the governments of Canada and Alberta. In addition, 1984 costs included charges of $58 million relating to the rescheduling of the Company's debt.

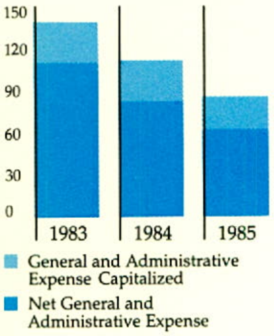
Of the Company's long term debt at the end of 1985 of $6,270 million, $5,354 million, or 85% is at floating interest rates. Consequently, interest expense is affected by fluctuations in interest rates in Canada and abroad. The average interest rate on the floating rate debt in 1985 was 10.6% compared with 12.0% in 1984 and 10.9% in 1983.

The interest rate on approximately 58% of the floating rate debt varies directly with the Canadian prime rate. In 1986, this rate has increased sharply from its year end level of 10% to as high as 13%, resulting in increased interest costs for this portion of debt. The Canadian prime rate has fallen to 10½% on May 1, 1986. The interest rate on the remaining 42% of floating rate debt is based on the London Interbank Offered Rate (LIBOR) and is generally fixed for a three or six month term. The impact of changes in this rate is therefore not immediately reflected in interest expense. U.S. 90 day LIBOR rates have declined since year end 1985 from 8% to 6⅞%.

Capitalized interest has decreased $29 million from 1984 due to a smaller balance of non-depleted oil and gas properties upon which interest is capitalized, and lower interest rates. These factors, along with the cessation of interest capitalization on frontier area costs, resulted in a decrease of capitalized interest of $114 million in 1985 as compared with 1983.

In 1985, the Canadian dollar declined in value approximately 5% against the U.S. dollar compared with a decline of 6% in 1984. However, the foreign exchange loss charged to operations in 1985 was substantially lower than in 1984, principally because of the implementation of the Debt Rescheduling Agreement. Under Canadian accounting practice, foreign exchange gains and losses on long term debt are deferred and amortized over the remaining period of the debt. In 1984, when a large portion of the Company's U.S. dollar debt was currently due, the related foreign exchange loss was charged immediately to operations. In 1985, the rescheduling of the Company's debt over the

General and Administrative Costs
Millions of Canadian Dollars



period to 1995 and the resulting deferral and amortization of foreign exchange gains and losses over this period have significantly reduced the immediate impact of the 5% decline in the dollar in 1985 on the results of operations. In 1983, a large portion of the Company's debt was also current. However the exchange rate declined only marginally, resulting in a foreign exchange loss of $27 million. See Note 21 to the consolidated financial statements for differences in the treatment of foreign exchange gains and losses under U.S. accounting rules.

General and administrative expense, after deduction of capitalized amounts and recoveries from third parties, decreased in 1985 by $21 million and $49 million compared with 1984 and 1983 respectively. These reductions of 25% and 44% respectively are primarily due to the continuing benefits of cost reduction measures initiated over the past two years. These measures included reductions in employee staff levels, a reduction in employee savings plan share contributions, subleasing excess office space, lease terminations and the introduction, in late 1983, of an early retirement program. The Company does not expect that future reductions in general and administrative expense will be as significant as those achieved to the end of 1985.

Income Taxes

In 1985, the Company provided for income taxes of $240 million despite having income before income taxes of only $206 million. This result occurred because certain items are not deductible for tax purposes, the most significant being Petroleum and Gas Revenue tax and depletion, depreciation and amortization on the excess of the purchase price of assets acquired over their tax values. The Company has available to it substantial amounts of unused deductions for tax purposes. As a result of claiming part of these for tax purposes in 1985, almost all of the tax provision is deferred and the Company had only a small current income tax provision.

The current income tax expense includes $22 million related to U.S. income. This amount is offset by the use of U.S. tax losses carried forward which had not previously been recognized for accounting purposes as the Company had not been certain that the losses would be used before they expired. This benefit is shown as an extraordinary item in the statement of operations.

The 1985 provision for income taxes is $202 million greater than in 1984. Taxable income for accounting purposes increased mainly due to the improvement in income and because the Company no longer had earned depletion deductions for accounting purposes as they had been fully utilized by the end of 1984.

The 1984 current income tax provision includes a reversal of current income tax expense of $256 million and a corresponding increase in deferred income tax expense in respect of taxes for 1982 and 1983. This reversal resulted from remission orders granted by the Government of Canada and the Province of Alberta in connection with the closing of the Debt Rescheduling Agreement. These orders allow interest costs incurred by a subsidiary relating to a 1982 acquisition to be deducted from the taxable income of the company that was acquired.

In 1983, the Company recorded a net loss for the year before income taxes of $1,175 million, largely because of the write-down and loss on disposition of assets. The income tax provision, a reversal of $26 million, was relatively small in comparison as some of these write-downs and losses on disposal of assets were not deductible in 1983 in calculating the income tax provision.

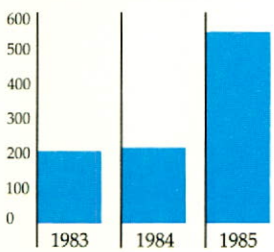
Effects of Changing Prices

The effects of inflation on the Company's operations are discussed in the unaudited supplementary information following the Company's financial statements and notes.

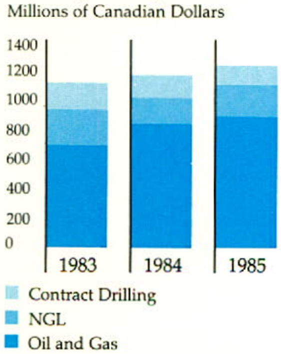
Financial Condition

a) Summary

Cash from Operations
Millions of Canadian Dollars



Cash Operating Income
Millions of Canadian Dollars



In 1985 the Company's financial condition continued to show significant improvement. The cash balance at December 31, 1985 was $466 million and the Company had a positive working capital balance ($178 million) for the first year since 1980 (1984 -$81 million deficiency; 1983 - $2,741 million deficiency).

Cash flow from operations, at $542 million for 1985, has more than doubled over both 1984 and 1983 levels of $209 million and $199 million respectively. The improvement was largely due to the substantial drop in interest and financing costs in 1985. Cash operating income also continued to show improvement over the prior years, largely reflecting reduced cash operating expense.

The Company's program of dispositions of non-core assets over the past three years has provided a significant amount of cash. Since substantially all assets are pledged as security, a large part of the cash proceeds have been used to reduce debt. Proceeds from dispositions in 1984 and 1983 of $139 million and $563 million respectively were almost all used to reduce debt. Asset dispositions in 1985 generated cash of $142 million of which $3 million was applied to debt.

The Debt Rescheduling Agreement contains a requirement that the Company dispose of assets for proceeds of at least $150 million by December 31, 1986. The Company had undertaken to dispose of 10 million of its Dome Mines shares by the same date. In February 1986, the Company disposed of 10 million Dome Mines shares for net proceeds of $147 million which were applied against debt. This sale, together with other 1985 dispositions, satisfies both of these requirements.

The Company was also successful in raising $114 million of net cash proceeds from a public equity issue in May of 1985. The issue was composed of 34 million units each of which included a common share and half a common share purchase warrant. This issue satisfied a requirement to raise equity under the Debt Rescheduling Agreement.

Meeting these requirements completes all the specific commitments of the Company under the Debt Rescheduling Agreement. The Company also complied with all the financial covenants under this agreement to December 31, 1985.

Capital expenditures, before capitalized interest and general and administrative expenses, were $139 million in 1985, as compared with $129 million and $287 million in 1984 and

1983 respectively. In addition to its own capital expenditures, the Company is continuing to develop its oil and gas assets through a farmout program.

Cash used for financing activities increased in 1985 compared with 1984 largely as a result of a reduction in accounts payable and accrued liabilities (included in "other-net" in the consolidated statement of cash flows). This reduction occurred mostly in the first quarter of 1985 and resulted from a decrease in interest payable on income taxes, a decrease in taxes payable due to a lump sum payment of Petroleum and Gas Revenue Tax and other general current liability reductions.

b) Sensitivities

The Company's financial position is dependent upon a number of factors beyond its control including the level of interest rates, crude oil and natural gas prices, the condition of crude oil and natural gas markets and the exchange rate between the Canadian and U.S. dollars. The following table summarizes the pro forma effect on the Company's results of operations for 1985 of changes in certain of these factors:

Variable	1985 Average Level	Change	Impact on: Net Income	Impact on: Cash (2)
			($Cdn. millions)	
Interest rates on floating rate debt	10.6%	1%	$27	$54
Prices (1)				
Crude oil and field NGL (per barrel)	Cdn. $33.47	Cdn. $1.00	9	20
Natural gas (per MCF)	Cdn. $ 2.60	Cdn. $0.10	6	14
Volumes (1)				
Crude oil and field NGL	87 Mb/d	1 Mb/d	1	6
Natural gas	591 MMcf/d	10 MMcf/d	1	6

(1) Crude oil and natural gas royalty rates vary with price and individual well productivity. Thus the impact of changes is not linear for larger volume and price changes.

(2) The tax effect of these changes is assumed to be deferred and thus would have no impact until the Company becomes currently taxable.

The decline in the value of the Canadian dollar against the U.S. dollar in 1985 benefited the Company in cash terms as the increase in revenues on crude oil and NGL sales and export sales of natural gas more than offset the increase in exchange costs on interest and debt repayments. Net income is affected by a combination of these factors and the amortization of unrealized foreign exchange losses related to the principal of U.S. dollar denominated debt. (See Note 21 to the consolidated financial statements.)

The recent decline in world oil prices will have a severe impact on the Company's cash flow if prices continue at current levels without offsetting change in other factors. To estimate the impact of a change in world oil prices, consideration must be given not only to the cash flow impact of reduced prices for oil production ($20 million per Cdn. $1 change in oil price as shown in the above table, or $28 million per U.S. $1 change) but also the indirect impact on other parts of the

Company's business. Natural gas competes with fuel oil in many markets, and must be priced competitively to retain sales. NGL prices tend to follow oil prices. Contract drilling income may also be affected by reduced oil prices. The timing and extent of the indirect impact of lower world oil prices on the Company's cash flow is difficult to forecast with any degree of certainty.

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c) Outlook

The Company is concerned about the steep decline in the international price of oil to levels as low as U.S. $10 per barrel in early 1986.

The average oil price received by the Company in 1985 was U.S. $25 per barrel (Cdn. $34). If oil prices continue at current levels, crude oil and field NGL revenues will decline significantly below 1985 levels. Natural gas prices in Canada will not be fully deregulated until November 1, 1986 but export prices are negotiable and will fluctuate. In addition, as domestic contracts expire, they may be renewed at freely negotiable prices. Revenues from natural gas sales in 1986 are expected to drop below 1985 levels.

The level of exploration activity in the Beaufort Sea is generally dependent on decisions which look to the longer term for oil prices. However, a decline in cash flows available to the industry from lower oil prices and the change in structure of government incentives will probably reduce revenues from the contract drilling segment in 1986.

Lower oil prices also have a significant adverse impact on revenues and operating income from the NGL business segment. Prices for various NGL products generally reflect the level of crude oil prices. As a result, continued lower oil prices through 1986 will reduce margins on NGL sales.

The budgeted level of capital expenditures in 1986 has been reduced in response to economic conditions and will continue to be reviewed throughout the year.

The Company's cash position will enable it to deal with lower oil prices for part of 1986. However, a continuation of lower oil prices without compensating interest rate reductions and changes in the fiscal regime will have a material adverse impact on the Company's liquidity. The Company's sources of cash are limited mainly to continuing operations. The availability and level of operating lines of credit depends on agreement with the lenders as to the level of acceptable accounts receivable to be pledged as security. Currently, the lenders have agreed to provide $40 million of operating lines of credit. This amount will fluctuate monthly depending on the level of acceptable accounts receivable. Subject to the acceptance by lenders of completed capital projects as security, the Company has contingently available a credit facility of up to $200 million and U.S. $29 million. The availability of these lines of credit may be changed or limited as a result of negotiation with the lenders regarding the interim plan discussed below.

If the Company met all scheduled interest and preferred share dividend payments, debt principal repayments and preferred share redemptions, the Company would experience a significant reduction in liquidity. Accordingly, the Company approached its affected lenders, including those who are party to the Debt Rescheduling Agreement with an interim plan. The proposed interim plan provides that the operation of certain portions of the Debt Rescheduling Agreement be suspended during the period from May 1, 1986 to October 28, 1986, with provision for extension to February 28, 1987. The main components of the interim plan are as follows:

(i) Throughout the term of the interim plan, certain interest and principal repayments will be deferred either in whole or in part. (See Note 8 to the consolidated financial statements).

(ii) Commencing May 1, 1986 the Company is suspending dividend payments and redemptions of all preferred shares. (See Notes 9 and 10 to the consolidated financial statements).

(iii) The rights of certain secured lenders to receive prepayments or be granted additional security under certain circumstances will be deferred until the end of the interim period.

(iv) Certain financial covenants will be suspended.

On April 30, 1986, the Company's lenders who are party to the Debt Rescheduling Agreement executed a waiver whereby they agreed to defer until May 30, 1986 the payments which would otherwise be due under the Debt Rescheduling Agreement during the period from and including April 30, 1986 to and including May 29, 1986. Dome Canada and Dome Mines signed deferral agreements whereby they also agreed to defer certain payments due for the same period. Dome Petroleum has deposited into escrow sufficient funds to pay all interest due and accrued up to and including April 30, 1986. Fifty per cent of the funds were released on April 30, 1986 and the remaining fifty per cent will be released upon the interim plan becoming effective or June 15, 1986, whichever occurs first.

The Company is seeking agreement with the affected lenders to the interim plan on or before May 30, 1986. There can be no assurance that the affected lenders will accept the interim plan. Failure to obtain an overall interim plan agreement with the affected lenders or additional waivers or extensions of debt due could lead to a default under one or more of the Company's credit agreements, which in turn could lead to an acceleration of substantially all of the Company's debt.

Should the interim plan be accepted the Company will approach the affected lenders to develop a permanent plan prior to the expiry of the interim plan.

In the absence of a significant improvement in oil prices or compensating interest rate reductions and changes in government fiscal policies, the Company's continued existence as a going concern in the short term is dependent upon the affected lenders' acceptance of an interim plan or upon the receipt of waivers or extensions and, in the longer term, on its ability to reach agreement with the affected lenders on a permanent plan. However, the resolution of these matters is not assured.

Dome Petroleum Limited
Consolidated Statement of Operations
Three Years Ended December 31, 1985
(Millions of Canadian Dollars, Except Per Share Amounts)

		1985	1984	1983
REVENUE	Crude oil and natural gas	**$1,181**	$1,090	$ 953
	Natural gas liquids	**1,011**	1,013	1,135
	Contract drilling	**244**	336	409
	Other	**—**	9	98
		2,436	2,448	2,595
EXPENSE	Operating expense			
	Crude oil and natural gas	**309**	268	249
	Natural gas liquids	**802**	834	895
	Contract drilling	**102**	171	221
	Other	**—**	12	119
	Depletion, depreciation and amortization	**376**	368	335
	Write-down of assets	**—**	—	1,099
	Loss (gain) on disposal of assets	**(66)**	(40)	65
	General and administrative	**62**	83	111
	Interest and financing	**655**	839	647
	Foreign exchange	**28**	123	27
	Other corporate	**(38)**	(23)	2
		2,230	2,635	3,770
		206	(187)	(1,175)
INCOME TAXES	Current	**33**	(249)	135
	Deferred	**207**	287	(161)
		240	38	(26)
		(34)	(225)	(1,149)
EQUITY IN EARNINGS OF ASSOCIATED COMPANIES		**19**	28	44
INCOME (LOSS) BEFORE EXTRAORDINARY ITEM		**(15)**	(197)	(1,105)
REDUCTION OF CURRENT INCOME TAXES ON UTILIZATION OF LOSS CARRY FORWARD		**22**	—	—
NET INCOME (LOSS)		**$ 7**	$ (197)	$(1,105)
Per common share (after deduction of preferred share dividends)				
Before extraordinary item		**$(0.09)**	$(0.84)	$ (4.72)
Net income (loss)		**$(0.02)**	$(0.84)	$ (4.72)

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

Dome Petroleum Limited
Consolidated Balance Sheet

December 31, 1985 and 1984
(Millions of Canadian Dollars)

ASSETS

		1985	1984
CURRENT	Cash and short term deposits		
	Restricted	$ —	$ 83
	Unrestricted	466	155
	Accounts receivable	631	497
	Inventories		
	Product	123	161
	Materials and supplies	50	62
		1,270	958
INVESTMENTS	Dome Mines Limited (quoted market value December 31, 1985 - $390; December 31, 1984 - $285)	251	244
	Less Dome Petroleum's pro rata interest in its common shares held by Dome Mines	(104)	(107)
		147	137
	Dome Canada Limited (quoted market value December 31, 1985 - $340; December 31, 1984 - $234)	429	413
		576	550
PROPERTY, PLANT AND EQUIPMENT		5,843	6,095
DEFERRED FOREIGN EXCHANGE		286	141
OTHER ASSETS		204	172
		$8,179	$7,916

The Company follows the full cost method of accounting.

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

LIABILITIES AND SHAREHOLDERS' DEFICIENCY

		1985	1984
CURRENT	Short term bank loans	$ —	$ 15
	Accounts payable and accrued liabilities	711	779
	Income and other taxes payable	12	40
	Long term debt due within one year	369	205
		1,092	1,039
LONG TERM DEBT		5,901	6,098
DEFERRED REVENUE		201	213
DEFERRED INCOME TAXES		805	668
REDEEMABLE PREFERRED SHARES	Issued by subsidiaries	350	220
	Issued by the Company	96	98
CONTINGENCIES AND COMMITMENTS (Notes 2 and 20)			
SHAREHOLDERS' DEFICIENCY	Preferred shares	105	109
	Common shares (issued and outstanding at December 31, 1985 - 331,219,556; December 31, 1984 - 278,564,775)	394	243
	Common share warrants	8	—
	Contributed surplus	50	46
	Deficit	(719)	(711)
	Dome Petroleum's pro rata interest in its common shares held by Dome Mines	(104)	(107)
		(266)	(420)
		$8,179	$7,916

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

On behalf of the Board:

John Macdonald
Director

John Beddome
Director

Dome Petroleum Limited
Consolidated Statement of Retained Earnings (Deficit)

Three Years Ended December 31, 1985
(Millions of Canadian Dollars)

		1985	1984	1983
RETAINED EARNINGS (DEFICIT), BEGINNING OF YEAR		**$(711)**	$(496)	$ 621
	Net income (loss)	**7**	(197)	(1,105)
		(704)	(693)	(484)
	Preferred share dividends			
	Stock	**(1)**	(2)	(1)
	Cash	**(11)**	(10)	(10)
	Other	**(3)**	(6)	(1)
DEFICIT, END OF YEAR		**$(719)**	$(711)	$ (496)

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

Auditors' Report

To the Shareholders of
Dome Petroleum Limited

We have examined the consolidated balance sheet of Dome Petroleum Limited as at December 31, 1985 and 1984 and the consolidated statements of operations, retained earnings (deficit) and cash flows for the three years ended December 31, 1985. 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, 1985 and 1984 and the results of its operations and the changes in its financial position for the three years ended December 31, 1985 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 3 to the consolidated financial statements, have been applied on a consistent basis.

Calgary, Canada
March 27, 1986

CLARKSON GORDON
Chartered Accountants

Comment of Auditors 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. Had our report been prepared in accordance with United States reporting standards, our opinion on the 1985 consolidated financial statements would have been qualified as being subject to the Company's ability to continue as a going concern, as referred to in Note 2 to these statements.

Calgary, Canada
March 27, 1986

CLARKSON GORDON
Chartered Accountants

Dome Petroleum Limited
Consolidated Statement of Cash Flows

Three Years Ended December 31, 1985
(Millions of Canadian Dollars)

		1985	1984	1983
OPERATING ACTIVITIES	Cash operating income	**$ 1,223**	$1,163	$1,111
	Interest and financing	**(678)**	(891)	(784)
	General and administrative	**(86)**	(112)	(140)
	Other — net	**83**	49	12
	Cash from operations	**542**	209	199
INVESTMENT ACTIVITIES	Expenditures on property, plant and equipment	**(139)**	(129)	(287)
	Other — net	**4**	12	75
	Cash used for investment	**(135)**	(117)	(212)
FINANCING ACTIVITIES	Long term debt			
	Increase	**3**	5	82
	Repayment	**(242)**	(268)	(578)
	Proceeds on disposal of assets	**142**	139	563
	Issue of common shares and warrants	**126**	33	47
	Other — net	**(193)**	137	206
	Cash from (used for) financing	**(164)**	46	320
INCREASE IN CASH		**243**	138	307
CASH, BEGINNING OF YEAR		**223**	85	(222)
CASH, END OF YEAR		**$ 466**	$ 223	$ 85

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.

Note 1. Summary of Significant Accounting Policies

Consolidated Financial Statements

The consolidated financial statements of the Company have been prepared on a going concern basis (see Note 2) in accordance with accounting principles generally accepted in Canada (see Note 21 for differences between Canadian and United States generally accepted accounting principles). These financial statements include the accounts of Dome Petroleum Limited and its subsidiary companies, except that Cyprus Anvil Mining Corporation (Cyprus) was not consolidated for the period from December 31, 1983 to November 21, 1985 since it was the Company's intention to dispose of this investment. The Company disposed of the mining assets of Cyprus on November 22, 1985.

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

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

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

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 the dates of acquisition.

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 Company's share of costs incurred in drilling in the frontier includes depreciation of drillships and related facilities and operating costs.

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 or 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.

Depletion, Depreciation and Amortization

The changed circumstances resulting from the deregulation of oil and gas prices in 1985 have caused the Company to conclude that it is no longer appropriate to base provisions for depreciation of production facilities and depletion of oil and gas properties on production revenues. Accordingly, the 1985 provision for depreciation and depletion has been calculated on the unit-of-production method based on estimated proved reserves as determined by Company or independent engineers. Prior to 1985 the provisions for depreciation of production facilities and depletion of oil and gas properties were calculated as the proportion of net property and production facility costs that current production revenues were to current plus estimated future revenues from proved reserves. The effect of this change on the results of operations for 1985 was to decrease the loss before extraordinary item and increase net income by $16 million ($0.06 per common share) net of deferred income taxes of $6 million.

Frontier costs are excluded from the depletion calculation until quantities of proved reserves can be ascertained through further exploration. Frontier costs are currently 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 million ($0.06 per common share) net of deferred income taxes of $7 million. Significant acquisition costs of unproved properties in western Canada are also 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.

The natural gas liquids system and 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.

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 provision for income taxes deferred principally as a result of claiming capital cost allowance, interest and exploration and development costs in excess of the related amounts provided in the accounts.

Net Income (Loss) Per Common Share

Net income (loss) per common share is calculated, after deduction of preferred share dividends, using the weighted average number of common shares outstanding reduced by the Company's pro rata interest in its outstanding common shares held by Dome Mines (1985 - 290 million; 1984 - 248 million; 1983 - 237 million).

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, 1985.

Note 2. Interim Plan

In early 1986, the international price of crude oil declined significantly. A continuation of lower oil prices, together with price declines for natural gas and natural gas liquids that could result, without compensating interest rate reductions and changes in government fiscal policies, will have a material adverse impact on the Company's revenue and cash flow (See Note 22 - Subsequent Event).

If the Company met all scheduled interest and preferred share dividend payments, debt principal repayments and preferred share redemptions, the Company would experience a significant reduction in liquidity. Accordingly, the Company approached its affected lenders, including those who are party to an agreement dated as of June 30, 1984, as amended and effective December 31, 1984, between the Company and certain of its lenders, including the credit facilities rescheduled thereunder, (the Debt Rescheduling Agreement), in March, 1986 with an interim plan. The interim plan provides that the operation of certain portions of the Debt Rescheduling Agreement be suspended during the period currently expected to be from May 1, 1986 to June 30, 1987 (the interim period). If the Company has not reached overall agreement with its affected lenders by April 30, 1986, it proposes to implement the interim plan and will therefore seek waivers or extensions of the debt due after that date. There can be no assurance that such consents will be granted. Failure to obtain an overall interim plan agreement with the affected lenders or timely waivers or extensions of debt due could lead to a default under one or more of the Company's credit agreements, which in turn could lead to an acceleration of substantially all of the Company's debt. The main components of the interim plan, the details of which are being negotiated with the affected lenders, are as follows:

(i) All scheduled payments of principal and interest will be made until April 30, 1986. Commencing May 1, 1986, certain interest and principal repayments will be deferred either in whole or in part. (See Note 8 - Long Term Debt - Deferral of Debt Repayments).

(ii) All preferred share dividends and preferred share redemptions will be made until April 30, 1986. Commencing May 1, 1986 the Company will suspend dividend payments and redemptions of all preferred shares. (See Notes 9 and 10).

(iii) The rights of certain secured lenders to receive prepayments or be granted additional security under certain circumstances will be deferred until the end of the interim period.

(iv) Financial covenants will be suspended.

The Company has requested agreements in principle from all of the affected lenders on or before April 30, 1986. Although the Company has been meeting with the affected lenders over the past weeks to discuss implementation and terms of the interim plan, no agreements have yet been reached and there can be no assurance that the affected lenders will accept the interim plan. Should the interim plan be accepted the Company will approach the affected lenders to develop a permanent plan prior to the expiry of the interim plan.

In the absence of a significant improvement in oil prices or compensating interest rate reductions and changes in government fiscal policies, the Company's continued existence as a going concern in the short term is dependent upon the affected lenders' acceptance of an interim plan or upon the receipt of waivers or extensions and, in the longer term, on its ability to reach agreement with the affected lenders on a permanent plan. However, the resolution of these matters is not assured.

Note 3. Changes in Accounting Policies

Frontier Exploration Costs

In 1983 the Company decided to concentrate its future capital expenditures on the development of assets in three strategic segments: 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 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. This change in 1983 resulted in an increase in the net loss for the year of $317 million ($1.34 per common share). See also Investments regarding a 1983 change in accounting policy by Dome Canada.

Foreign Currency Translation

Effective December 31, 1983, the Company commenced translation of 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 $19 million ($0.08 per common share).

Note 4. Investments

Dome Mines

At December 31, 1985 and 1984, the Company owned 30,861,184 common shares of Dome Mines of which 28,452,198 shares were pledged under certain of the Company's loan agreements.

The Company's holdings represent a 34.4% (1984 - 38.3%) interest therein, and Dome Mines together with its subsidiaries owned 22.0% (1984 - 24.0%) of the outstanding common shares of the Company, resulting in the Company having a pro rata interest of 7.4% (1984 - 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 reduction in the Company's interest in Dome Mines in 1985 and 1984 reflects equity issues by Dome Mines in which the Company did not participate. These issues resulted in a gain in 1985 of $13 million (1984 - $10 million) which is included in other corporate revenue.

The unamortized excess of the purchase price over the net book value of Dome Mines, other than its holdings in the Company, of $38 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.

In February, 1986 the Company sold 10 million common shares of Dome Mines for net cash proceeds of $147 million which were used to reduce long term debt. The sale resulted in a gain of $79 million, a decrease in the investment in Dome Mines of $81 million, a charge to the deficit of $13 million and a reduction in the Company's pro rata interest in its own common shares of $34 million. Income taxes of $24 million resulting from the gain will be eliminated by utilizing previously unrecorded capital loss carryforwards. As a result of this sale, the Company's interest in Dome Mines has been reduced to 23.2% and the Company's pro rata interest in its own common shares has decreased to 5%.

Dome Mines Summarized Financial Information

Balance Sheets

	December 31, 1985	1984
Current assets	**$ 143**	$ 92
Investments — Dome Petroleum Limited	**(56)**	(91)
— Other	**262**	14
Property, plant and equipment	**396**	394
	$ 745	$409
Current liabilities	**$ 57**	$ 34
Long term obligations	**92**	—
Deferred income and mining taxes	**132**	128
Deferred revenue	**1**	1
Minority interest	**191**	87
Shareholders' equity	**272**	159
	$ 745	$409

Statements of Income

	Years Ended December 31, 1985	1984	1983
Revenue	**$261**	$215	$ 235
Operating income	**$ 51**	$ 65	$ 123
Income before taxes and other items	**$ 60**	$ 81	$ 174
Income and mining taxes	**40**	45	79
Income after taxes, before other items	**20**	36	95
Income (losses) related to associated companies:			
Falconbridge Limited	**5**	—	—
Canada Tungsten Mining Corporation Limited	**(6)**	(1)	(2)
Dome Petroleum	**(14)**	(56)	(291)
Gain on share issues by associated companies	**12**	7	—
Minority interest	**(10)**	(12)	(18)
Income (loss) before extraordinary item	**7**	(26)	(216)
Extraordinary item			
Share of Dome Petroleum's recovery of income taxes	**5**	—	—
Net income (loss)	**$ 12**	$(26)	$(216)

Dome Canada

At December 31, 1985 and 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, 1985	1984
Current assets	**$ 295**	$ 323
Long term receivable — Dome Petroleum Limited	**101**	112
Property, plant and equipment	**1,144**	1,000
	$1,540	$1,435
Current liabilities	**$ 66**	$ 62
Deferred revenue	**24**	27
Long term debt	**227**	227
Deferred income and revenue taxes	**212**	144
Shareholders' equity	**1,011**	975
	$1,540	$1,435

Statement of Income

	Years Ended December 31, 1985	1984	1983 (1)
Revenue	**$212**	$189	$133
Operating income	**$ 74**	$ 66	$ 56
Income before taxes and other items	**$105**	$100	$ 79
Taxes	**(70)**	(68)	(39)
Gain on sale of TransCanada PipeLines Limited shares net of deferred income taxes	**—**	—	18
Write-down of Frontier costs net of deferred income taxes	**—**	—	(51)
Net income	**$ 35**	$ 32	$ 7

(1) During 1983, Dome Canada changed its accounting policy with respect to Frontier costs resulting in a reduction of net income of $51 million.

Note 5. Property, Plant and Equipment

		1985			1984		
	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:							
Western Canada							
Depleted	Unit of production (2)	$4,691	$1,004	$3,687	$4,422	$ 752	$3,670
Non-depleted (1)	—	105	—	105	302	—	302
Frontier (1)	6.7%	355	45	310	333	22	311
Oil sands:							
Mining and related facilities and developed rights	Unit of production (2)	144	18	126	132	14	118
Undeveloped rights	5.0%	243	46	197	243	34	209
Production facilities	Unit of production (2)	724	147	577	685	116	569
Natural gas liquids system and pipelines	2.5% to 6.7%	565	170	395	582	170	412
Drillships and other vessels	6.7% to 15.0%	652	297	355	648	246	402
Other	5.0% to 30.0%	173	82	91	170	68	102
		$7,652	$1,809	$5,843	$7,517	$1,422	$6,095

(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 by 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, 1985			Years Ended December 31,			
	Western Canada	Frontier	Total	1985	1984	1983	1982 and Prior
Acquisition costs	$ 709	$ 102	$ 811	$ —	$ —	$ —	$ 811
Exploration costs	—	430	430	22	—	(1)	409
Capitalized interest	486	276	762	22	51	129	560
Transfers to depletion base	(1,090)	—	(1,090)	(219)	(268)	(240)	(363)
Write-down	—	(453)	(453)	—	—	(453)	—
Amortization	—	(45)	(45)	(23)	(22)	—	—
	$ 105	$ 310	$ 415	$(198)	$(239)	$(565)	$1,417

(2) Depletion, depreciation and amortization rates

	Years Ended December 31,		
	1985	1984	1983
Oil and gas properties and production facilities			
Per dollar based on production revenue	**$ —**	$0.20	$0.20
Per barrel of production	**4.10**	—	—
Oil sands			
Per barrel of production	**3.19**	4.33	3.09

Note 6. Restricted Cash and Unused Lines of Credit

Restricted cash at December 31, 1984 was released in 1985, $35 million being applied to debt and $48 million released to the Company for general corporate purposes.

The availability and level of operating lines of credit depend upon agreement with the lenders as to the level of acceptable accounts receivable to be pledged as security. Currently, the lenders have agreed to provide $40 million of operating lines of credit. The amount of operating lines will vary monthly depending on the level of acceptable accounts receivable.

Subject to the acceptance by lenders of completed capital projects as security, the Company has contingently available a credit facility of up to $200 million and U.S. $29 million.

The Company's access to these lines of credit may be changed or limited as negotiations between the Company and its lenders continue with respect to the interim plan.

Note 7. Income Taxes

(a) 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 as follows:

	1985	1984	1983
Corporate tax rate	**47.1%**	47.1%	47.1%
Calculated income tax provision	**$ 97**	$ (88)	$(553)
Add (deduct) the tax effect of			
Crown charges disallowed for tax purposes, less provincial rebates	**145**	147	115
Federal resource allowance	**(132)**	(128)	(99)
Earned depletion allowance	**(1)**	(62)	9
Non-deductible interest	**12**	32	23
Preferred share dividends of subsidiaries	**6**	7	16
Non-deductible depletion and depreciation	**55**	56	45
Petroleum and gas revenue tax (PGRT)	**65**	61	51
Non-deductible foreign exchange	**11**	44	8
Capital loss on write-down of assets	**—**	—	268
Differences between the Canadian rate and those rates applicable to foreign and mining operations	**(1)**	(12)	28
Capital loss (gain) on disposal of assets	**(20)**	(17)	40
Gain on deemed disposition of shares of Dome Mines	**(6)**	(5)	—
Reversal of tax provision on disposition of a subsidiary	**—**	10	—
Other	**9**	(7)	23
Income tax provision	**$ 240**	$ 38	$ (26)

(b) The income tax provision is calculated on the basis of revenue and expense recorded in the consolidated statement of operations. Deferred income taxes arising from timing differences in the treatment of these items for financial statement purposes compared to the treatment for statutory income tax purposes are as follows:

	1985	1984	1983
Depreciation, depletion and amortization	**$179**	$ (2)	$(114)
Interest — capitalized	**11**	24	56
— other (1)	**(13)**	239	(120)
Other capitalized expenses	**11**	14	1
Other	**19**	12	16
	$207	$287	$(161)

(1) 1984 includes the effect of the remission orders described below.

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

	1985			1984			1983		
	Canada	**Foreign**	**Total**	Canada	Foreign	Total	Canada	Foreign	Total
Income (loss) before income taxes, equity earnings and extraordinary item	**$ 130**	**$ 76**	**$ 206**	$(216)	$ 29	$(187)	$(969)	$(206)	$(1,175)
Income taxes:									
Current	**$ 10**	**$ 23**	**$ 33**	$(251)	$ 2	$(249)	$ 133	$ 2	$ 135
Deferred	**207**	**—**	**207**	287	—	287	(161)	—	(161)
	$ 217	**$ 23**	**$ 240**	$ 36	$ 2	$ 38	$ (28)	$ 2	$ (26)

Effective December 31, 1984, the Company received income tax remission orders allowing interest costs related to a subsidiary's 1982 acquisition to be deducted from the taxable income of the acquired company. The effect of these remission orders in the 1984 consolidated financial statements was to reduce current income taxes payable and increase deferred income taxes by $256 million in respect of 1982 and 1983 income taxes accrued but unpaid.

(d) At December 31, 1985, the Company had the following tax loss carryforwards, investment tax credits and realized 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
1986	$ —	$ 28	$ —	$ —
1987	—	—	—	—
1988	—	—	—	—
1990 and thereafter	449	—	119	12
	$ 449	$ 28	$ 119	$ 12

Note 8. Long Term Debt

	Currency of Repayment	Repayment Dates	1985	1984
Bonds and Debentures				
Secured				
Income Debenture with interest at 52% of the prime bank rate plus ⅞%	Cdn.	1989 to 1995	**$ 200**	$ 200
10½% Series A Debentures	U.S.	1986 to 1993	**160**	165
14¾% Sinking Fund Debentures	U.S.	1992 to 2006	**135**	129
7.85% Collateral Trust Bonds net of funds on deposit of U.S. $2 million (1984 - U.S. $2 million)	U.S.	1994	**—**	—
10⅜% Sinking Fund Debentures	Cdn.	1986 to 1996	**22**	24
Unsecured				
10% Sinking Fund Debentures	U.S.	1986 to 1994	**61**	62
13½% Purchase Fund Debentures	U.S.	1986 to 1992	**52**	52
5¾% Purchase Fund Bonds	SF	1986 to 1991	**65**	51
7¼% Purchase Fund Bonds	SF	1986 to 1990	**68**	51
Term Bank Loans and Promissory Notes				
Secured				
6%	Cdn.	1986 to 1998	**60**	65
Up to 16%	Cdn.	By 2030	**175**	175
Prime plus 5%, payable to Dome Canada	Cdn.	1986 to 1990	**112**	112
Prime plus ⅜% to prime plus 1⅜%	Cdn.	1986 to 1995	**2,386**	2,476
LIBOR plus ⅝%	U.S.	1987 to 1995	**66**	62
LIBOR plus ¾%	U.S.	1986 to 1995	**1,393**	1,421
Unsecured				
16¼%	U.S.	1989	**4**	4
6%	SF	1986	**62**	51
10.84%	DM	1986 to 1991	**14**	10
Prime less ⅛% to prime plus 1⅛%	Cdn.	1987 to 1995	**214**	214
LIBOR plus ¼%	U.S.	1988	**105**	99
LIBOR plus ¼%	U.S.	1989	**70**	66
LIBOR plus ⅝% to LIBOR plus ¾%	U.S.	1987 to 1995	**595**	563
U.S. prime	U.S.	1985	**—**	2
Other				
Revenue Canada — Taxation (PGRT)	Cdn.	1986 to 1990	**213**	204
Leases and other —	Cdn.	Various	**31**	38
—	U.S.	Various	**7**	7
			6,270	6,303
Less amounts due within one year			**369**	205
			$5,901	$6,098

Approximate instalments (including sinking fund requirements) in each of the years 1986 to 1990 are (in millions): 1986 - $369; 1987 - $403; 1988 - $421; 1989 - $416 and 1990 - $500.

At December 31, 1984, a $187 million nonrecourse secured term bank loan was offset by an account receivable of an equal amount from a third party. In 1985 the third party assumed the term bank loan in return for cancellation of the account receivable.

Deferral of Debt Repayments

As described in Note 2, the Company has approached affected lenders with an interim plan. Should an interim plan be accepted, the Company will approach the affected lenders to develop a permanent plan prior to expiry of the interim plan. The Company expects to renegotiate payment of deferred principal and interest as part of such a permanent plan. The interim plan provides that effective May 1, 1986, scheduled payments pursuant to the Debt Rescheduling Agreement and the Company's other debt will be adjusted as follows:

- Payments to certain secured lenders holding debt totalling $3,787 million at December 31, 1985 will be based on net cash flows generated by the pledged assets less associated capital expenditures and general and administrative expenses. Payments will first be applied to interest and then to principal. The Company will, in an interest deferral certificate, acknowledge and confirm to each such lender its obligation to pay deferred interest at the end of the interim period. All deferred principal will also be payable at the end of such interim period.
- Payments to certain lenders holding debt totalling $763 million at December 31, 1985 will include interest and sinking fund payments except for final principal payments which are due during the period of the interim plan. The Company will be negotiating arrangements to have such payments refinanced or converted into equity.
- Payments to certain secured lenders holding debt totalling $360 million at December 31, 1985, will be suspended during the interim period unless the corporate investments pledged as underlying security are sold. The Company will, in an interest deferral certificate, acknowledge and confirm to each such lender its obligation to pay deferred interest at the end of the interim period. All deferred principal is to be payable approximately three months after the end of such interim period.
- Payments to all other lenders holding debt totalling $1,360 million at December 31, 1985 will be suspended during the interim period. The Company will, in an interest deferral certificate, acknowledge and confirm to each such lender its obligation to pay deferred interest at the end of the interim period. All deferred principal is to be payable approximately three months after the end of such interim period.

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.

The promissory notes with cost of borrowing of up to 16% are held by Arctic Petroleum Corporation of Japan. The notes are secured by floating charge debentures 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 million in 1981 and 1982 to be used in conducting exploration activities in the Beaufort Sea. The first $175 million was assigned to the Company and the remaining $225 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 unless default occurs at an earlier date in which event the principal amount is payable on demand. Any other repayment of the principal amount prior to 2030, 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, with any payment being 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. Under certain circumstances, the whole of the Company's proceeds of production from certain fields which may be developed in the Beaufort Sea may be required to service the debt obligation, which is to be paid solely out of the proceeds of such production.

Debt Rescheduling Agreement

Under the terms of the Debt Rescheduling Agreement which closed on February 5, 1985 and was effective December 31, 1984, approximately $5.3 billion of the Company's debt was rescheduled over the period to 1995. The effect of the Debt Rescheduling Agreement at December 31, 1984 was to reclassify $2.7 billion from current liabilities to long term debt. The Debt Rescheduling Agreement contains the following significant provisions (See Note 2 - Interim Plan):

(a) New uniform covenants which are in addition to existing covenants, requiring, among other things:

  (i) The Company's working capital ratio (the ratio of current assets to current liabilities, as defined in the Debt Rescheduling Agreement) may not fall below 0.7 to 1 as at the end of two consecutive quarterly periods to March 31, 1988 and 0.8 to 1 after December 31, 1987. At December 31, 1985 the Company's working capital ratio was 1.2 to 1;

  (ii) 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 $281 million, after reflecting proceeds of $114 million from the equity issue, at December 31, 1985, negative $315 million at December 31, 1986, negative $215 million at December 31, 1987 and negative $25 million at December 31, 1988 and thereafter in excess of $100 million and equal to or greater than, for 1989, 90% of the Company's consolidated capital base at December 31, 1988 and thereafter, 90% of the average of the consolidated capital base as at the end of each of the two immediately preceding fiscal year ends. At December 31, 1985 the Company's consolidated capital base was negative $95 million;

(iii) 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 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;

(iv) 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 (See Note 9 - Redeemable Preferred Shares Issued by Subsidiaries). 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 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, 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) Additional interest is payable on all rescheduled debt principal at the rate of ⅛% per annum commencing in April, 1987, and increasing by an additional ⅛% per annum in April of 1990 and 1993; and

(d) 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 for 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 credit facility must be used to prepay that facility.

Concurrently with the closing of the Debt Rescheduling Agreement, the Company reached agreement with Revenue Canada - Taxation to pay its 1982 and 1983 PGRT liabilities over a five year period commencing January 2, 1986 with interest at the rate prescribed by the Income Tax Act (Canada) and with Dome Canada to reschedule certain current obligations over the five year period commencing January 2, 1986.

Note 9. Redeemable Preferred Shares Issued by Subsidiaries

		1985		1984		1983	
	Authorized	**Outstanding**	**Amount**	Outstanding	Amount	Outstanding	Amount
Provo Gas Producers Limited Series A	**2,200,000**	**2,200,000**	**$220**	2,200,000	$220	2,200,000	$220
136908 Canada Ltd.	**1,300,000**	**1,300,000**	**130**	—			—
			$350		$220		$220

The 2,200,000 Series A, redeemable, cumulative, non-voting, first preferred shares have a dividend rate of 52% of the prime bank rate plus ¾%. Provo Gas Producers Limited (Provo) has agreed to redeem, at par, 97,400 shares over two years commencing in 1987 with the remaining shares to be redeemed in 1989. In respect of the remaining redemption obligation in 1989, the Company and Provo have arranged for an unsecured term bank loan repayable from 1989 to 1995.

The preferred shares issued by 136908 Canada Ltd., a wholly-owned subsidiary of Cyprus, are included in redeemable preferred shares issued by subsidiaries as a result of the consolidation of Cyprus with effect from November 21, 1985. (See Summary of Significant Accounting Policies - Consolidated Financial Statements.) The 1,300,000 cumulative, non-voting, first preferred shares have a dividend rate of 60% of the prime bank rate plus ¾%, increasing by ⅛% in April of 1987. 136908 Canada Ltd. has agreed to redeem, at par, 87,240 shares over three years commencing in 1987 with the remaining shares to be redeemed in 1990. In respect of the remaining redemption obligation in 1990, 136908 Canada Ltd. has arranged for an unsecured term bank loan repayable from 1990 to 1995.

The redemption obligations and the resulting unsecured term bank loans of both of the above share issues are subject to the terms and conditions of the Debt Rescheduling Agreement.

The Company plans to suspend dividends and redemptions on redeemable preferred shares issued by subsidiaries on May 1, 1986 (See Note 2 - Interim Plan).

Note 10. Preferred Shares

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

Outstanding:

		1985		1984		1983	
	Authorized	Outstanding	Amount	Outstanding	Amount	Outstanding	Amount
Redeemable at the option of the Company:							
7.76% Series A and B	10,500,000	4,593,321	$109	4,705,572	$113	4,847,649	$117
Stock dividends		63,633	1	107,949	1	107,223	2
Purchased		(224,560)	(5)	(220,200)	(5)	(249,300)	(6)
		4,432,394	$105	4,593,321	$109	4,705,572	$113
Redeemable at the option of the holder:							
8.725% Series C	1,450,000	1,450,000	$ 36	1,450,000	$ 36	1,450,000	$ 36
Redeemed		(72,500)	(2)	—	—	—	—
		1,377,500	34	1,450,000	36	1,450,000	36
7.25% Series D	4,110,517	4,110,517	62	4,110,517	62	4,110,517	62
		5,488,017	$ 96	5,560,517	$ 98	5,560,517	$ 98

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 $25.80 per share to August 31, 1986, declining thereafter by $0.20 per share annually to $25 after August 31, 1989. 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.

The Series C Cumulative Preferred Shares were issued at $25 per share with an annual requirement to redeem 72,500 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 will be adjusted in 1989 and 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. From July, 1982 the holder has received in lieu of dividends, interest at the bank prime rate plus 2% on an agreed redemption amount of $62 million. On March 12, 1986 the Series D Shares were exchanged for an equal number of newly authorized Series 1 Subordinated Convertible Preferred Shares (Series 1 Shares) redeemable at the Company's option at $15 per share together with any accumulated but unpaid dividends. The holder of the Series 1 Shares shall be entitled to receive cumulative dividends, as and when declared by the Board of Directors, equal to the sum of a fixed cash amount of $1.50 per share per annum payable in equal quarterly instalments and 10% per annum, payable quarterly in cash or common shares at the Company's option, of any dividends accrued but unpaid on any previous payment date. After March 12, 1987, at the option of the holder, the Series 1 Shares are convertible into 18,515,842 common shares. The Series 1 Shares are redeemable at the option of the holder at any time after January 4, 1996, or earlier in the event that the Company fails to pay the required dividend on three payment dates. Upon any such redemption the holder is entitled to receive $15 per share plus accrued but unpaid dividends to the date of redemption. Additional exchange, conversion and redemption entitlements could apply under certain specified conditions.

The Company plans to suspend dividends and redemptions on preferred shares on May 1, 1986 (See Note 2 - Interim Plan).

Note 11. Common Shares

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

Issued (cancelled):

	1985		1984		1983	
	Shares	**Amount**	Shares	Amount	Shares	Amount
Equity issue	**34,000,000**	**$106**	—	$ —	—	$ —
Issued to lenders	**12,223,757**	**27**	—	—	—	—
Employee Profit Sharing Plan	**6,244,000**	**17**	10,470,843	32	9,248,895	42
Employee Share Bonus Plans	**—**	**—**	27,000	—	517,757	3
Exercise of options	**179,337**	**1**	326,757	1	825,005	2
Share purchase plans	**—**	**—**	(151,250)	—	(105,875)	—
Exchange for shares of a subsidiary	**7,687**	**—**	2,122	—	6,375	—
Net increase in common shares outstanding	**52,654,781**	**151**	10,675,472	33	10,492,157	47
Common shares outstanding, beginning of year	**278,564,775**	**243**	267,889,303	210	257,397,146	163
Common shares outstanding, end of year	**331,219,556**	**$394**	278,564,775	$243	267,889,303	$210

On May 14, 1985 the Company completed an equity issue of 34 million units, each consisting of one common share and one half common share purchase warrant, plus an additional 250,000 warrants, for aggregate net cash proceeds of $114 million. Each whole warrant enables the holder to purchase one common share of the Company up to December 15, 1986 for $3.80. As partial consideration for rescheduling its debt, the Company issued 12,223,757 common shares having a value of $27 million and charged this amount to operations in 1984.

At December 31, 1985, 41,910,645 common shares (1984 - 19,761,707) of the Company were reserved for issue as follows:

(a) 9,486,262 (1984 - 5,730,262) for issue to the Employee Profit Sharing Plan at prevailing market prices,

(b) 7,824,245 (1984 - 8,173,620) for Employee Share Bonus Plans and stock options,

(c) 4,500,000 (1984 - 3,000,000) under options granted to Mr. J.H. Macdonald, Chairman and Chief Executive Officer of the Company,

(d) 2,750,000 (1984 - 2,750,000) for an option granted to Morgan Stanley & Co. Incorporated,

(e) 17,250,000 for exercise of common share warrants,

(f) 100,138 (1984 - 107,825) for shares of a subsidiary not yet presented for exchange.

The change in the number of shares issuable under outstanding options during the year ended December 31, 1985 is as follows:

Options outstanding, beginning of year	12,866,570
Granted (1)	4,182,725
Exercised (2)	(349,375)
Cancelled (1)	(3,194,590)
Options outstanding, end of year (3)	13,505,330

(1) During the year 1,965,750 of the options cancelled that were exercisable at prices ranging from $2.75 to $5.625 per share, were replaced with options exercisable at $2.75 per share.

(2) All options exercised during the year were at an exercise price of $2.75 per share. Of the 179,337 shares issued on the exercise of options, 144,850 were issued for cash and 34,487 were issued in respect of stock appreciation rights on 204,525 options.

(3) At December 31, 1985, 11,294,505 options were then exercisable at prices ranging from $2.75 to $5.875 per share. The remaining 2,210,825 options, 1,500,000 of which were granted to Mr. J.H. Macdonald subject to shareholder approval, will be exercisable on varying dates to 1995 at $2.75 per share.

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, 1985, $5 million (1984 - $5 million) was receivable under the above arrangements.

Note 12. Contributed Surplus

	1985	1984	1983
Contributed surplus, beginning of year	**$46**	$ 8	$5
Gain on purchase and cancellation of preferred shares	**4**	2	3
Gain on expiry of common share warrants, net of deferred income taxes of $11 million	**—**	36	—
Contributed surplus, end of year	**$50**	$46	$8

Note 13. Write-Down of Assets

In 1983, the Company wrote down the carrying values of non strategic assets in the amount of $1,099 million before deferred income taxes of $202 million. This write-down was comprised of frontier oil and gas properties, mining assets, United States oil and gas properties, and costs of certain deferred or terminated projects and other costs related to the Company's refinancing activities.

Note 14. Disposal of Assets

During 1985, the Company sold rights in the Primrose area of Alberta, the Producers/Westspur Pipe Line system and certain other assets including the mining assets of Cyprus. Total cash proceeds amounted to $142 million and resulted in a gain of $66 million before deferred income taxes of $5 million. The sale of these assets, along with the disposition of 10 million common shares of Dome Mines in February, 1986 which fulfilled an undertaking with the Company's lenders, satisfied a covenant in the Debt Rescheduling Agreement to sell assets for aggregate cash proceeds of at least $150 million.

The Company sold assets during 1984, including its 22.9% interest in Sovereign Oil & Gas PLC, for total proceeds of $139 million which resulted in a gain of $40 million before deferred income taxes of $10 million.

During 1983, the Company sold assets, including virtually all of its producing and exploratory lands in the United States, and its interest in TransCanada PipeLines Limited, for total proceeds of $563 million. These disposals resulted in a loss of $65 million before deferred income tax charges of $12 million.

Note 15. Interest and Financing

Interest and financing included in the statement of operations is comprised of the following:

	1985	1984	1983
Interest on long term debt	**$650**	$711	$ 679
Other interest and financing charges	**14**	164	71
Preferred share dividends of subsidiaries	**14**	16	34
Less interest capitalized	**(23)**	(52)	(137)
Interest and financing	**$655**	$839	$ 647

Note 16. Cash Flows

The consolidated statement of cash flows has 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. See also Note 2 - Interim Plan.

(a) Operating Activities

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

	1985	1984	1983
Revenue	**$2,436**	$2,448	$2,595
Cash operating expense			
Crude oil and natural gas	**309**	268	249
Natural gas liquids	**802**	834	895
Contract drilling	**102**	171	221
Other	—	12	119
	1,213	1,285	1,484
Cash operating income	**$1,223**	$1,163	$1,111

(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 $47 million, $81 million and $166 million in 1985, 1984 and 1983 respectively.

(b) Investment Activities

Expenditures on property, plant and equipment are before capitalized items as follows:

	1985	1984	1983
Capital expenditures	**$186**	$210	$ 453
Deduct:			
Capitalized interest	**(23)**	(52)	(137)
Capitalized general and administrative expense	**(24)**	(29)	(29)
	$139	$129	$ 287

(c) Changes in Working Capital

	1985	1984	1983
(i) Changes in cash:			
Cash and short term deposits			
Restricted	**$ (83)**	$ (25)	$ 108
Unrestricted	**311**	83	70
Short term bank loans	**15**	80	129
Increase in cash	**$ 243**	$ 138	$ 307
(ii) Cash effect of changes in other working capital items:			
Accounts receivable	**$(134)**	$ 106	$ 228
Inventories			
Product	**38**	(10)	32
Material and supplies	**12**	23	108
Accounts payable and accrued liabilities	**(68)**	(163)	(121)
Income and other taxes payable	**(28)**	(447)	220
Long term debt due within one year	**164**	(2,031)	8
	(16)	(2,522)	475
Add (deduct):			
Long term debt due within one year	**(164)**	2,031	(8)
Other items related to the Debt Rescheduling Agreement	**—**	648	(134)
Net cash effect	**$(180)**	$ 157	$ 333

The net cash effect relates to the following activities and is included in Other - net.

	1985	1984	1983
Operating	**$ 23**	$ —	$ —
Investing	**4**	10	138
Financing	**(207)**	147	195
	$(180)	$ 157	$ 333

Note 17. Related Party Transactions

Dome Canada

The Company is party to certain agreements with Dome Canada including the Dome Exploratory Lands Agreement (DELA), which enables Dome Canada to earn interests in certain exploratory and development lands in return for the obligation to fund related exploration and development and an agreement with respect to the majority of Dome Canada's administration, which is carried out by the Company on behalf of Dome Canada. The DELA will terminate on July 6, 1986.

With respect to these agreements, the Company charged Dome Canada $105 million in 1985 (1984 - $206 million; 1983 - $303 million).

Dome Canada holds a secured promissory note of the Company in the amount of $112 million which bears interest at prime plus 5% and is repayable on January 2 in each of the following years (in millions): 1986 - $11; 1987 - $17; 1988 - $22; 1989 - $28; and 1990 - $34. During 1985 the Company paid interest to Dome Canada of $18 million (1984 - $15 million; 1983 - $12 million) in respect of this note. The Company plans to suspend payment of principal and interest on this liability effective May 1, 1986 (See Note 2 - Interim Plan).

At December 31, 1985, the Company's accounts receivable include $57 million from Dome Canada (1984 - $48 million).

Dome Mines

During 1985, the Company paid Dome Mines $11 million (1984 - $11 million; 1983 - $12 million) with respect to a $225 million guarantee of certain term bank loans and received dividends of $4 million (1984 - $4 million; 1983 - $3 million).

The status of this fee after April 30, 1986 is uncertain at this time, and future payment will be dependent upon the final terms of the interim plan. (See Note 2 - Interim Plan).

Note 18. Information by Business Segment and Geographic Area

The principal business segments of the Company are:

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

BUSINESS SEGMENTS

	1985	1984	1983
Revenue			
Crude oil and natural gas	**$1,181**	$1,090	$ 953
Natural gas liquids	**1,011**	1,013	1,135
Contract drilling	**244**	336	409
Other operating	**—**	9	98
	$2,436	$2,448	$ 2,595
Transfers Between Business Segments (not included above)			
Crude oil and natural gas	**$ 78**	$ 43	$ 31
Contract drilling	**44**	1	2
Eliminations	**(122)**	(44)	(33)
	$ —	$ —	$ —
Operating Income			
Crude oil and natural gas	**$ 561**	$ 534	$ 443
Natural gas liquids	**187**	159	219
Contract drilling	**99**	113	145
Other operating	**—**	(11)	(31)
	847	795	776
Gain (Loss) on Write-Down and Disposal of Assets			
Crude oil and natural gas	**76**	1	(667)
Natural gas liquids	**12**	1	—
Contract drilling	**1**	2	(12)
Other operating	**—**	6	(460)
	89	10	(1,139)
Income (Loss) Before Corporate Revenue and Expense	**936**	805	(363)
Corporate (Revenue) Expense			
General and administrative	**62**	83	111
Interest and financing	**655**	839	647
Loss (gain) on disposal of investments and corporate assets	**23**	(30)	(21)
Write-down of corporate assets	**—**	—	46
Foreign exchange	**28**	123	27
Other corporate expense (revenue)	**(38)**	(23)	2
Income taxes	**240**	38	(26)
Equity in earnings of associated companies	**(19)**	(28)	(44)
	951	1,002	742
Income (loss) before extraordinary item	**(15)**	(197)	(1,105)
Reduction of current income taxes on utilization of loss carry forward	**22**	—	—
Net Income (Loss)	**$ 7**	$ (197)	$(1,105)

BUSINESS SEGMENTS

	1985	1984	1983
Identifiable Assets			
Crude oil and natural gas	**$5,273**	$5,534	$ 5,672
Natural gas liquids	**872**	758	818
Contract drilling	**444**	448	577
Other operating	**—**	12	99
	6,589	6,752	7,166
Deferred foreign exchange	**286**	141	73
Investments	**576**	550	551
Other corporate	**728**	473	388
	$8,179	$7,916	$ 8,178
Capital Expenditures			
Crude oil and natural gas	**$ 161**	$ 178	$ 359
Natural gas liquids	**18**	14	12
Contract drilling	**4**	10	17
Other operating	**—**	—	20
	183	202	408
Other corporate	**3**	8	45
	$ 186	$ 210	$ 453
Depletion, Depreciation and Amortization			
Crude oil and natural gas	**$ 311**	$ 288	$ 261
Natural gas liquids	**22**	20	21
Contract drilling	**43**	52	43
Other operating	**—**	8	10
	376	368	335
Other corporate	**15**	14	17
	$ 391	$ 382	$ 352

GEOGRAPHIC AREAS

	1985	1984	1983
Revenue			
Canada	**$2,165**	$2,121	$ 2,166
United States	**271**	327	429
	$2,436	$2,448	$ 2,595
Transfers Between Geographic Areas			
Canada	**$ 150**	$ 253	$ 306
United States	**—**	31	16
Eliminations	**(150)**	(284)	(322)
	$ —	$ —	$ —
Operating Income			
Canada	**$ 794**	$ 761	$ 754
United States	**53**	34	22
	847	795	776
Gain (Loss) on Write-Down and Disposal of Assets			
Canada	**89**	10	(968)
United States	**—**	—	(171)
	89	10	(1,139)
Income (Loss) Before Corporate Expense	**936**	805	(363)
Corporate Expense (as detailed in Business Segments)	**951**	1,002	742
Income (Loss) Before Extraordinary Item	**(15)**	(197)	(1,105)
Reduction of current income taxes on utilization of loss carry forward	**22**	—	—
Net Income (Loss)	**$ 7**	$ (197)	$(1,105)
Identifiable Assets			
Canada	**$7,179**	$7,053	$ 7,332
United States	**138**	172	222
	7,317	7,225	7,554
Deferred foreign exchange	**286**	141	73
Investments	**576**	550	551
	$8,179	$7,916	$ 8,178

Transfers are accounted for at prices comparable to open market prices for similar products and services. Natural gas that is ultimately exported cannot be readily identified.

Effective with deregulation of crude oil prices on June 1, 1985, the Company began marketing all of its domestic production, approximately 20% of which was exported. Prior to deregulation, approximately 81% of the Company's domestic crude oil production was sold to the Alberta Petroleum Marketing Commission, a provincial government agency.

Note 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: 1985 - $18; 1984 - $30; 1983 - $38.

Note 20. Contingencies and Commitments

In addition to the contingencies described in Notes 2 and 8 the Company has the following contingent liabilities and commitments:

(a) 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 million.

Revenue Canada - Taxation has notified the Company that a capital loss incurred by the Company in 1981 is under review and may be adjusted. The Company believes that the capital loss, deducted in 1982, is valid and would contest the issue if Revenue Canada - Taxation issues a notice of reassessment adjusting the amount of the capital loss. The Company is presently unable to estimate the effect, if any, on the consolidated financial statements of an ultimate resolution of this matter; and

(b) The Company's future minimum operating lease payments are estimated at $117 million, comprised of (in millions): 1986 - $22; 1987 - $19; 1988 - $14; 1989 - $12; 1990 - $11; and thereafter - $39.

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.

Note 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.

Statement of Operations

	1985	1984	1983
Income (loss) before extraordinary item in accordance with the Canadian basis as reported	**$ (15)**	$ (197)	$(1,105)
Add (deduct) adjustments for:			
Full cost accounting (a)	**4**	—	341
Foreign currency translation (b)	**(145)**	(67)	(2)
Investment tax credits (c)	**(33)**	(6)	6
Other	**—**	—	3
Income (loss) before extraordinary item in accordance with the U.S. basis	**(189)**	(270)	(757)
Reduction of current income taxes on utilization of loss carry forward	**22**	—	—
Net income (loss) in accordance with the U.S. basis	**$ (167)**	$ (270)	$ (757)
Per common share (after deduction of preferred share dividends)			
Before extraordinary item	**$(0.69)**	$(1.14)	$ (3.24)
Net income (loss)	**(0.62)**	(1.14)	(3.24)

Balance Sheet

	1985		1984	
	Canadian basis	**U.S. basis**	Canadian basis	U.S. basis
Investment in Dome Canada (a)	**$ 429**	**$ 459**	$ 413	$ 437
Property, plant and equipment (a)	**5,843**	**6,292**	6,095	6,548
Deferred foreign exchange (b)	**286**	**—**	141	—
Deferred income taxes (a) (c)	**805**	**887**	668	719
Redeemable preferred shares issued by the Company	**96**	**201**	98	207
Preferred shares	**105**	**—**	109	—
Deficit (d)	**719**	**607**	711	425

Notes to Statement of Operations and Balance Sheet

(a) Under U.S. full cost accounting rules, the Company would be permitted only one cost centre for the capitalization of Canadian exploration and development costs. Accordingly, the 1983 adjustment reverses the write-down of frontier costs, net of deferred income taxes, by the Company and its equity accounted associate Dome Canada. The write-down, before deferred income taxes, is then added to the single cost centre and depleted for U.S. purposes. The adjustment in 1985 therefore represents the difference, net of deferred income taxes, between the amortization of frontier costs for Canadian purposes and depletion expense on the write-down reversal for U.S. purposes. There was no effect on the results of operations in 1984.

Under U.S. rules the carrying value of the Company's oil and gas properties is limited, at the end of each reporting period, to an amount (the ceiling amount) equal to the present value of future net revenues, discounted at 10% and based on period end prices and costs, plus the cost of properties not being depleted and unproved properties at the lower of cost or net realizable value, all adjusted for related income tax effects. In addition, U.S. rules require that if a price decline occurs subsequent to the reporting period, which would have resulted in the carrying value of oil and gas properties exceeding the ceiling amount at the reporting period end if such prices had been used, disclosure of the amount of the excess is required.

Had the Company used crude oil prices of U.S. $14 per barrel, which is representative of the trading price of crude oil on March 21, 1986, in calculating the ceiling amount at December 31, 1985 the carrying value of its oil and gas properties would have exceeded the ceiling amount and net loss reported for U.S. purposes would have been increased by approximately one billion dollars ($3.45 per common share), net of related deferred income taxes.

At the present time the Company is unable to estimate the impact that the recent international crude oil price declines will have on its March 31, 1986 accounts for U.S. purposes.

(b) Under U.S. rules, exchange gains and losses arising on translation of long term liabilities at year end are included in income immediately instead of being deferred and amortized over the life of such liabilities.

(c) The 1985 and 1984 adjustments reverse investment tax credits previously recognized only under U.S. rules which will expire without being realized.

(d) At December 31, 1985, the deficit of the Company included $136 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.

Note 22. Subsequent Event

The carrying value of the Company's oil and gas properties for each of its cost centres is limited to an 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 or net realizable value, all adjusted for related income tax effects. The determination of the present value of future net revenues is based on prices, costs, production levels, and existing economic factors as determined by Coles Nikiforuk Pennell Associates Ltd., consulting petroleum engineers, of Calgary, Alberta. At December 31, 1985, based on conditions existing at that date, there was no impairment of the carrying value of the Company's oil and gas properties.

In early 1986, the international price of crude oil declined significantly. If such price declines, without compensating changes in other factors used in the determination of future net revenues from proved properties, are determined by the Company in consultation with its petroleum consulting engineers to be other than temporary, a write-down of the carrying value of the Company's oil and gas properties could result. The Company is unable to determine the future impact, if any, of these crude oil price declines on the carrying value of its oil and gas properties.

Unaudited Supplementary Information
(Millions of Canadian Dollars, Except as Otherwise Noted)

Oil and Gas Producing Activities

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

Securities and Exchange Commission (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.

Reserves for each of the three years reflect the results of independent assessments as reported in the March 21, 1986, March 20, 1985, and April 12, 1984 letter reports from Coles Nikiforuk Pennell Associates Ltd. and Mr. Harold Hammar.

Oil and gas exploration and production activities have been carried on principally in Canada following the disposition of the Company's U.S. oil and gas interests in 1983.

Capitalized Costs Relating To Oil and Gas Producing Activities

	1985	1984
Oil and gas properties		
Proved	**$4,663**	$4,490
Unproved	**1,212**	1,252
Less accumulated depletion, depreciation and amortization	**1,196**	890
Net capitalized costs	**$4,679**	$4,852
Company's proportionate interests in capitalized costs of companies accounted for by the equity method	**$ 576**	$ 514

Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities

	1985	1984	1983
Property acquisition			
Proved	**$ —**	$ 1	$ 54
Unproved	**—**	—	—
Exploration (1)	**59**	85	156
Development (2)	**89**	86	144
Company's proportionate interests in costs of property acquisition, exploration, and development of companies accounted for by the equity method	**97**	81	122

(1) Includes capitalized interest (in millions): 1985 - $22; 1984 - $51 and 1983 - $129 and capitalized general and administrative costs (in millions): 1985 - $17; 1984 - $25 and 1983 - $23.

(2) Includes capitalized interest (in millions): 1985 - $ Nil; 1984 - $1 and 1983 - $6 and capitalized general and administrative costs (in millions): 1985 - $7; 1984 - $4 and 1983 - $4.

Results of Operations For Oil and Gas Producing Activities

	1985	1984	1983 (a)
Revenue	**$1,114**	$1,032	$ 900
Production costs	**275**	237	226
Depletion and depreciation	**294**	272	244
Write-down of assets	**—**	—	583
Loss (gain) on disposal of assets	**(1)**	(1)	84
	546	524	(237)
Income tax expense	**388**	320	119
Results of operations from producing activities (excluding corporate overhead and interest costs)	**$ 158**	$ 204	$(356)
Company's proportionate interests in results of operations for producing activities of companies accounted for by the equity method	**$ 11**	$ 9	$ (8)

(a) The results of operations of U.S. activities are included until sold; the write-down and loss on disposal amounts include $104 million and $73 million respectively in relation to these activities.

Reserve Quantity Information

		Oil (2) (millions of barrels)	Gas (1) (billions of cubic feet)
Proved reserves at December 31, 1982 (3)		465	5,840
Revisions of previous estimates		(111)	(888)
Purchase of minerals in place		6	101
Extensions and discoveries		11	65
Production		(27)	(174)
Sales of minerals in place		(26)	(186)
Proved reserves at December 31, 1983		318	4,758
Revisions of previous estimates		39	72
Extensions and discoveries		10	89
Production		(29)	(196)
Sales of minerals in place		—	(51)
Proved reserves at December 31, 1984		338	4,672
Revisions of previous estimates		**(26)**	**(138)**
Extensions and discoveries		**10**	**54**
Production		**(29)**	**(211)**
Proved reserves at December 31, 1985		**293**	**4,377**
Proved developed reserves at December 31:	1982	383	3,990
	1983	249	3,174
	1984	268	3,107
	1985	**247**	**2,939**
Company's proportionate interests in proved reserves of companies accounted for by the equity method at December 31:			
	1982	25	288
	1983	26	302
	1984	26	321
	1985	**28**	**335**

(1) Gas reserves are adjusted to a standard heat content of 1,000 British thermal units per cubic foot.

(2) Includes natural gas liquids reserves of (in millions of barrels): 1985 - 90; 1984 - 92; 1983 - 84 and 1982 - 104.

(3) Includes oil and gas reserves of 21 million barrels and 118 billion cubic feet respectively in the U.S. which were sold in 1983.

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, 1985, 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.

Reserves at December 31, 1985

	Proved Developed	Proved Undeveloped	Total Proved
Before deduction of Provincial Royalties			
Crude Oil (millions of barrels)	186	17	203
Natural Gas Liquids (millions of barrels) (i)	61	29	90
Natural Gas (billions of cubic feet) (ii)	2,939	1,438	4,377
After deduction of Provincial Royalties			
Crude Oil (millions of barrels)	159	16	175
Natural Gas Liquids (millions of barrels) (i)	45	20	65
Natural Gas (billions of cubic feet) (ii)	2,337	1,146	3,483

(i) Includes pentanes plus.

(ii) Natural gas volumes have been adjusted to a standard heat content of 1,000 British thermal units per cubic foot.

Standarized 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 and 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. See Note 21 to the consolidated financial statements.

Standarized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	1985	1984	1983
Future cash inflows	**$17,190**	$17,296	$18,292
Future production and development costs	**4,186**	4,729	5,329
Future income taxes	**6,091**	6,151	6,455
Future net cash flows	**6,913**	6,416	6,508
less 10% annual discount for estimated timing of cash flows	**3,794**	3,165	3,220
Standardized measure of discounted future net cash flows	**$ 3,119**	$ 3,251	$ 3,288
Company's proportionate interests in standardized measure of discounted future net cash flows of companies accounted for by the equity method	**$ 256**	$ 261	$ 254

Principal Sources of Change in the Standardized Measure of Discounted Future Net Cash Flows

	1985	1984	1983
Production	**$(848)**	$(801)	$ (722)
Net changes in prices and production costs	**(762)**	(539)	283
Extensions, discoveries and improved recovery, less related costs	**112**	131	114
Development costs incurred during the period	**83**	82	101
Revisions of previous quantity estimates	**(294)**	260	(1,354)
Accretion of discount	**576**	576	617
Net change in income taxes	**(489)**	(42)	534
Sales of reserves in place	**—**	(46)	(287)
Other — purchase of reserves	**—**	—	119
— petroleum and gas revenue tax	**903**	—	—
— Crown royalty	**559**	—	—
— adjustments and changes	**28**	342	667
	$(132)	$ (37)	$ 72

Effects of Changing Prices

Traditional financial statements summarize transactions which are based on historical cost and reported in accordance with generally accepted accounting principles. There is general agreement that, in prolonged periods of significant inflation, traditional financial statements do not reflect the impact of changes in prices of specific goods and services purchased, produced and used by the enterprise and changes in the general purchasing power of the dollar.

The Canadian Institute of Chartered Accountants (CICA) recognizes the unique and specialized nature of the oil and gas industry in that the current cost of acquiring or replacing similar reserves is hypothetical and subject to considerable uncertainty. The CICA has however, concluded that its recommendations on the effects of changing prices should be extended to the industry and certain selected additional disclosures with respect to reserve quantities should be made. These disclosures are contained as part of Reserve Quantity Information. The following information has been prepared in accordance with CICA recommendations, which, although different in format and in the details of disclosure, have similar objectives to FASB Statement No. 33.

Basis For Determining Current Costs

While the Company has prepared this information using what it believes are reasonable assumptions and estimates, different and equally valid assumptions would culminate in significantly different results. Additionally, the determination of the current cost of oil and gas reserves recommended by the CICA requires a high degree of subjective judgement. The Company cautions the reader that these current cost estimates are hypothetical and do not necessarily represent amounts for which the assets could be purchased and are not comparable with current cost information of other companies. The replacement of the Company's reserves at current cost is subject to considerable uncertainty as actual replacement reserves are more likely to come from non-conventional sources or in the longer term from the frontier.

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 net 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. The current cost of inventories and other assets was estimated based on current suppliers' prices and recent costs.

The decline in international crude oil prices in early 1986, if continued, may affect future current cost amounts of the Company's assets.

Interpretation of Results

Reference is made to the accompanying Consolidated Statement of Operations, Other Supplementary Information and Consolidated Balance Sheet Information which compare the differences between historical cost and current cost information.

(a) Consolidated Statement of Operations

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. The net loss on a current cost basis in 1985 was $402 million, an increase of $375 million when compared with the historical cost net loss attributable to common shareholders. The factors causing this difference are set out below:

Operating expense and depletion, depreciation and amortization — The cost of natural gas liquid product increased $30 million on a current cost basis while depreciation, depletion and amortization increased $72 million and other expenses $4 million when compared with the historical cost basis. In addition, the Company did not reflect a gain on disposal of assets in 1985 on a current cost basis, as the assets sold had previously been reflected at their current values in 1984 on the current cost basis. The increase in depreciation, depletion and amortization reflects higher current cost for property, plant and equipment compared with their historical cost.

Increase (decrease) in the current cost of inventory and property, plant and equipment held during the year — Represents the increase in the current costs attributable to the effects of general inflation and the increase (decrease) attributable to the specific prices of the inventory, property, plant and equipment items totalling $135 million.

Increase in the current cost of inventory and property, plant and equipment attributable to the effect of general inflation — Reflects the effect of changes in the general purchasing power of the dollar by indicating the increase required in the value of these assets to keep pace with inflation. This charge, included in the decrease of $135 million discussed above measures the extent to which the current cost of these assets has kept pace with inflation as measured by the Consumer Price Index.

Gain in general purchasing power from holding net monetary liabilities — Represents the gain to the Company from holding monetary obligations, principally debt, in excess of monetary assets of cash and accounts receivable which, due to inflation, will be discharged with dollars of declining purchasing power.

(b) Other Supplementary Information

The increase in the current cost of assets may be proportionally attributed to the holders of debt (including preferred shares) and equity. The financing adjustment is the benefit attributable to the common shareholders resulting from that portion of the increase in the current cost of assets during the year deemed to be financed by debt and can be calculated on two bases.

(c) Consolidated Balance Sheet Information

The current cost of inventory and property, plant and equipment shows an excess over historical cost of $1,753 million which relates primarily to western Canada lands and natural gas liquids. While this excess is calculated in accordance with 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.

Effects of Changing Prices Two Years Ended December 31, 1985

Consolidated Statement of Operations	Historical Cost	Current Cost	
	1985	**1985**	1984
Revenue	**$2,436**	**$2,436**	$2,546
Operating expense, including cost of natural gas liquid product	**1,213**	**1,243**	1,334
Depletion, depreciation and amortization	**376**	**448**	517
Gain on disposal of assets	**(66)**	**—**	(42)
Other expenses — net	**688**	**692**	1,019
Income taxes — current	**33**	**33**	(259)
— deferred	**207**	**207**	299
Loss	**(15)**	**(187)**	(322)
Preferred share dividends	**12**	**12**	13
Increase (decrease) in the current cost of inventory and property, plant and equipment held during the year	**—**	**(135)**	100
Net loss attributable to common shareholders in nominal dollars	**$ (27)**	**(334)**	$ (235)
Increase in current cost of inventory and property, plant and equipment attributable to the effect of general inflation		**(346)**	(331)
Gain in general purchasing power from holding net monetary liabilities		**278**	266
Loss attributable to common shareholders in constant dollars		**$ (402)**	$ (300)

The 1984 comparative amounts have been restated in 1985 average dollars.

Other Supplementary Information	Current Cost	
	1985	1984
Financing adjustment		
Based on changes in the current cost amounts of inventory and property, plant and equipment	**$ (111)**	$ 82
Based on the current cost adjustments made to income	**$ 88**	$ 96

The 1984 comparative amounts have been restated in 1985 average dollars.

Consolidated Balance Sheet Information	Historical Cost	Current Cost	
	December 31, 1985	**December 31, 1985**	December 31, 1984
Inventory	**$ 173**	**$ 174**	$ 235
Property, plant and equipment	**5,843**	**7,595**	8,441
Net assets (common shareholders' equity)	**(371)**	**1,382**	1,530

The 1984 comparative amounts have been restated in December, 1985 dollars.

Selected Quarterly Financial Data

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(Millions of Canadian Dollars, Except per Share Amounts)				
1985					
Revenue	**$589**	**$567**	**$609**	**$671**	**$2,436**
Operating income (1)	**193**	**188**	**242**	**224**	**847**
Income (loss) before extraordinary item	**(23)**	**2**	**19**	**(13)**	**(15)**
Net income (loss)	**(23)**	**2**	**19**	**9**	**7**
Per common share					
Before extraordinary item	**(0.10)**	**—**	**0.05**	**(0.05)**	**(0.09)**
Net income (loss)	**(0.10)**	**—**	**0.05**	**0.02**	**(0.02)**
1984 (2)					
Revenue	634	553	580	681	2,448
Operating income (1)	200	194	190	211	795
Net income (loss)	(40)	(61)	(4)	(92)	(197)
Per common share	(0.18)	(0.26)	(0.02)	(0.38)	(0.84)

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

(2) Certain 1984 comparative amounts have been reclassified to conform with the presentation adopted in 1985.

Market for the Company's Common 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)		
	High	Low	Volume (Thousands)	High	Low	Volume (Thousands)
1984						
1st quarter	$4.55	$3.65	7,723	$3.69	$2.94	13,729
2nd quarter	4.05	3.00	6,466	3.19	2.19	10,108
3rd quarter	3.35	2.10	11,806	2.63	1.56	14,910
4th quarter	3.05	2.07	6,251	2.31	1.56	13,279
1985						
1st quarter	**$3.65**	**$2.00**	**18,058**	**$2.69**	**$1.50**	**15,658**
2nd quarter	**3.60**	**2.60**	**10,741**	**2.63**	**1.94**	**10,930**
3rd quarter	**3.15**	**2.70**	**10,593**	**2.38**	**1.94**	**10,964**
4th quarter	**3.55**	**2.50**	**16,931**	**2.56**	**1.81**	**18,781**

The number of registered holders of common shares of the Company on March 20, 1986 was 45,950. 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 (See Note 2 to the consolidated financial statements).

Five Year Financial Review
(Millions of Canadian Dollars, Except per Share Amounts)

	1985	1984	1983	1982	1981
Revenue (after royalties and revenue taxes)					
Oil and gas operations					
Crude oil and field natural gas liquids	**$ 737**	$ 651	$ 606	$ 571	$ 411
Natural gas	**368**	368	325	371	284
Sulphur and other	**76**	71	22	70	27
Total crude oil and natural gas	**1,181**	1,090	953	1,012	722
Natural gas liquids	**1,011**	1,013	1,135	1,044	866
Contract drilling	**244**	336	409	506	413
Other	**—**	9	98	288	171
	2,436	2,448	2,595	2,850	2,172
Expense					
Operating expense					
Crude oil and natural gas	**309**	268	249	265	209
Natural gas liquids	**802**	834	895	805	632
Contract drilling	**102**	171	221	315	238
Other	**—**	12	119	325	182
Depletion, depreciation and amortization	**376**	368	335	306	160
Write-down of assets	**—**	—	1,099	213	—
Loss (gain) on disposal of assets	**(66)**	(40)	65	155	(18)
General and administrative	**62**	83	111	99	46
Interest and financing	**655**	839	647	807	534
Foreign exchange	**28**	123	27	22	11
Other corporate	**(38)**	(23)	2	(60)	(21)
Gain on cancellation of preferred shares	**—**	—	—	(70)	—
	2,230	2,635	3,770	3,182	1,973
	206	(187)	(1,175)	(332)	199
Provision for income taxes	**240**	38	(26)	94	78
Equity in earnings of associated companies	**19**	28	44	57	78
Income (loss) before extraordinary item	**(15)**	(197)	(1,105)	(369)	199
Reduction of current income taxes on utilization of loss carry forward	**22**	—	—	—	—
Net income (loss)	**$ 7**	$ (197)	$(1,105)	$ (369)	$ 199

	1985	1984	1983	1982	1981
Per common share					
Before extraordinary item	**$(0.09)**	$(0.84)	$(4.72)	$(1.71)	$ 0.80
Net income (loss)	**(0.02)**	(0.84)	(4.72)	(1.71)	0.80
Average number of common shares outstanding (in millions)	**290**	248	237	224	223
Cash from operations (a)	**$ 542**	$ 209	$ 199	$ 104	$ 85
Capital expenditures and acquisitions (b)					
Crude oil and natural gas	**$ 114**	$ 98	$ 194	$ 494	$ 2,593
Natural gas liquids	**18**	13	11	29	102
Contract drilling	**4**	10	17	43	245
Other	**3**	8	65	30	519
	$ 139	$ 129	$ 287	$ 596	$ 3,459
Total assets	**$8,179**	$7,916	$ 8,178	$9,917	$10,209
Long term debt obligations and redeemable preferred shares (excluding current portion)	**$6,347**	$6,416	$ 4,069	$4,616	$ 6,628

(a) The Company formerly reported funds generated from operations, a working capital definition versus the cash definition adopted in 1984. To facilitate comparison with other companies, funds generated from operations for 1985 were $581 (1984 - $484; 1983 - $201; 1982 - $224 and 1981 - $389).

(b) Exclusive of capitalized interest and general and administrative expenses.

The consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada. If the consolidated 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:

	1985	1984	1983	1982	1981
Net income (loss)	**$ (167)**	$ (270)	$ (757)	$ (413)	$ 244
Per common share					
Before extraordinary item	**(0.69)**	(1.14)	(3.24)	(1.91)	1.00
Net income (loss)	**(0.62)**	(1.14)	(3.24)	(1.91)	1.00
Write-down of assets	**—**	—	(646)	(214)	—
Long term obligations	**6,452**	6,525	4,182	4,803	6,747
Total assets	**8,372**	8,252	8,583	9,915	10,203

Exchange Rates

The exchange rates at the end of each of the 5 years ended December 31, 1985 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).

	1985	1984	1983	1982	1981
Annual average	**$.7308**	$.7720	$.8114	$.8101	$.8340
Last day	**.7151**	.7566	.8035	.8132	.8430
High in year	**.7575**	.8033	.8201	.8430	.8499
Low in year	**.7130**	.7492	.7993	.7691	.8048

Five Year Operating Review

	1985	1984	1983	1982	1981
Production Volumes (1)					
Crude oil (thousands of barrels per day)					
Canada — conventional and heavy	**65**	67	62	65	57
— synthetic	**5**	3	4	3	3
Foreign	—	—	2	8	9
Natural gas liquids	**17**	14	14	17	10
Total petroleum liquids	**87**	84	82	93	79
Natural gas (millions of cubic feet per day)	**591**	551	485	585	476
Sulphur (long tons per day)	**1,181**	994	885	826	577
Natural gas liquids — straddle plants (thousands of barrels per day)	**35**	34	28	31	30
Sales Volumes (1)					
Natural gas liquids (thousands of barrels per day)	**113**	110	116	123	119
Sulphur (long tons per day)	**1,723**	1,721	1,112	2,126	804
Gross Wells (including farmouts)					
Exploratory — Canada — oil	**103**	67	63	110	68
gas	**57**	41	46	129	226
dry	**117**	97	60	111	147
Exploratory — Foreign — oil	—	—	—	14	32
gas	—	—	—	7	11
dry	—	—	—	53	86
Total gross exploratory wells	**277**	205	169	424	570
Development — Canada — oil	**871**	729	627	280	274
gas	**264**	221	136	264	339
dry	**98**	113	77	72	71
Development — Foreign — oil	—	—	—	60	164
gas	—	—	—	24	30
dry	—	—	—	13	38
Total gross development wells	**1,233**	1,063	840	713	916
Total gross wells	**1,510**	1,268	1,009	1,137	1,486
Reserves (millions of barrels) (2)					
Estimated reserves of oil, natural gas liquids and oil equivalent of natural gas	**1,103**	1,201	1,200	1,541	1,969
Land Holdings (thousands of acres)					
Gross working interest	**52,913**	57,957	66,291	72,343	123,322
Net working interest	**21,933**	24,597	26,798	27,825	53,867
Gross royalty interest (3)	**10,853**	11,677	11,689	10,807	28,422

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

(2) Stated before Crown but after other royalties. Values subsequent to 1982 reflect consultants' proved reserves estimates, defined by the SEC, plus 55 million (1984 - 57 million and 1983 - 62 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, 1985) in approximately 17 million gross acres of its working interest lands.

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

H. Michael Burns,
Toronto, Ontario
President, Crownx Inc.

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, Q.C.,* **
Calgary, Alberta
Partner in the law firm of
Bennett Jones

Allen T. Lambert, O.C.,**
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, F.C.A.,
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,
Exploration & Land

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

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

A. Boyd Anderson
Vice-President,
Marketing & Natural
Gas Liquids

Earle L. Forgues
Vice-President,
Engineering

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

Roy G. Millice
Vice-President, Exploration

John R. Moore
Vice-President, Exploitation

Robert M. Scarborough
Vice-President, Heavy Oil

James C. Smith
Vice-President, Administration
& Human Resources

George W. Watson
Vice-President, Finance

Karl G. Leitl
Controller

Ernest F.H. Roberts
Treasurer

John F. Scott
Secretary

E. Susan Evans
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Stock Listing

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Preferred Shares
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The National 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 1985 Annual Report on 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
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