Suncor inc.

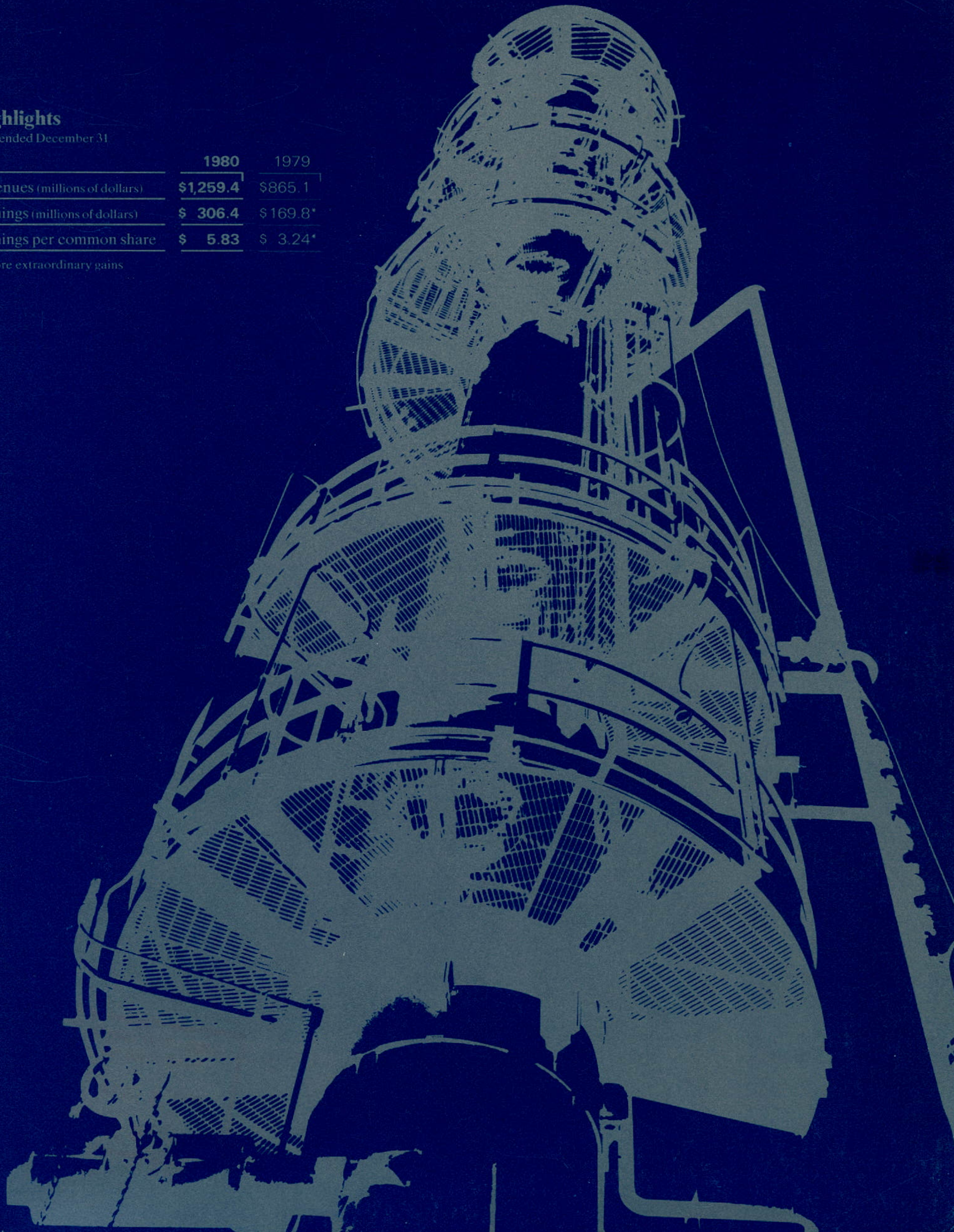
Annual Report 1980

Highlights

Year ended December 31

	1980	1979
Revenues (millions of dollars)	$1,259.4	$865.1
Earnings (millions of dollars)	$ 306.4	$169.8*
Earnings per common share	$ 5.83	$ 3.24*

*Before extraordinary gains



Company Profile

Suncor Inc., one of Canada's largest oil companies, was the first in the world to tap the enormous potential of the oil sands on a commercial scale. Today, Suncor operates both mining and steam stimulation projects recovering hydrocarbons from the oil sands of Alberta. The Company explores for, and produces, conventional crude oil and natural gas in Canada's western provinces and participates in the search for oil and gas in the frontier areas of the Arctic Islands, the Beaufort Sea, the Mackenzie Delta and offshore Labrador.

Suncor manufactures, distributes and markets gasolines, petrochemicals, home heating oil, heavy fuel oil, lubricants and specialty products under the Sunoco and Sunchem names. The Company owns and operates a refinery in Sarnia, Ontario.

Suncor is independently directed and managed by Canadians and pursues a policy of responding to Canadian needs. A majority of its common shares are owned by Sun Company, Inc. of the United States.

The Suncor Tower in Calgary, headquarters for the Company's Resources Group.

Front Cover: *Symbolizing our proposed multi-million dollar refinery upgrading, one of our Sarnia facility's fractionators juts into the sky — just one of the ventures representing Suncor's commitment to meeting the petroleum needs of Canadians. Fractionators separate hydrocarbon streams into their various components.*

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Summary of Results

Financial (dollars in millions except per share data)	**1980**	1979
Revenues	**$1,259.4**	$865.1
Earnings before extraordinary gains	**$ 306.4**	$169.8
Funds from operations	**$ 418.0**	$252.4
Purchases of properties, plant and equipment	**$ 271.9**	$132.8
Shareholders' equity	**$1,102.3**	$797.6
Earnings as a percentage of shareholders' equity	**32.3%**	24.3%
Earnings as a percentage of capital employed	**24.6%**	18.2%
Earnings before extraordinary gains per common share	**$ 5.83**	$ 3.24
Funds from operations per common share	**$ 8.00**	$ 4.84
Dividends paid per preferred share	**$ 1.92**	$ 0.53

Suncor practises energy conservation. The Sarnia refinery's energy requirements per unit of throughput have been reduced by 22 per cent since 1972.

Operating	**1980**	1979
Gross production		
Conventional crude oil and natural gas liquids (a)	**940**	983
Synthetic crude oil (a)	**2 716**	2 465
Gross natural gas sales (b)	**628**	640
Crude oil processed at Suncor refinery (a)	**4 525**	4 454
Sales of refined products (a)	**4 260**	4 307
Gross proven reserves		
Conventional crude oil and natural gas liquids (b)	**10**	12
Synthetic crude oil (b)	**56**	65
Natural gas (billions of cubic metres)	**13**	14

(a) thousands of cubic metres
(b) millions of cubic metres

President's Report

It was a very unsettling year for Suncor. After seven months of uncertainty waiting for the federal government to review our world pricing agreement for synthetic crude oil, we were stunned by the decision, contained in the new National Energy Program, to slash the price for our current levels of oil sands production by more than half. No other single event in our 62-year history in Canada has been so damaging to our prospects.

Operationally, 1980 was a successful year. Earnings were up substantially, due primarily to higher prices for synthetic crude in the first ten months of the year, increased synthetic crude production and improved margins for most refined products. New initiatives were aggressively pursued in resources development and refining. However, earnings for the final quarter were down from the same period of 1979 because of the synthetic crude oil price reduction which came into effect on November 7, and oil sands production losses due to a leak in our natural gas pipeline which supplies energy to the plant. Our oil sands operations actually recorded a loss in December.

As the year ended, the urgent priority was to seek a revision in the price obtained for our oil sands production. An exceedingly strong case was made to Ottawa for the higher synthetic crude price granted to Syncrude and to new oil sands plants. The facts support our position and we are guardedly optimistic that parity with Syncrude will be obtained in the near future. In the interim, no capital spending initiatives have been cancelled, although many projects valuable to Canada are on hold as we await a decision from Ottawa. The details of our case are presented on page five.

The Year in Review

Apart from the shift in synthetic crude pricing, the most significant developments in 1980 were the progress of our oil sands plant expansion, a major increase in exploration activity and a preliminary decision to upgrade our Sarnia refinery.

The expansion is gratifying proof of Suncor's engineering and management skills. In an industry where cost over-runs are considered normal and at a time when inflation is near record levels, we have brought this highly complex project close to completion while remaining on budget and on schedule. The work will be finished this year but the full effects of this 25 per cent increase in capacity will not be felt until 1982.

Exploration activity was sharply higher, reflecting the improved profitability of the Company. In the western provinces, we participated in 38 completed gross exploratory wells in 1980 compared to 24 in 1979. Discoveries totalled 18, twice the number of the previous year. This quick acceleration demonstrated our commitment to western Canada and fulfilled our aim of better balancing provincial and frontier exploration.

In the Arctic Islands, two of three wells drilled on Suncor interests in 1980 found gas; one of them, Char G-07 was a significant new discovery. Three more wells were spudded in 1981 and one of these, Skate B-80, was a gas discovery in mid-February. Drilling was continuing at all three locations as we wrote this report. Prospects for the Arctic Islands become more promising with each drilling season.

In July, our Board of Directors gave its approval to an upgrading of our refinery at a preliminary estimated cost of $200 million to enable it to produce more gasoline and home heating oil. This decision is subject to engineering and feasibility studies which are now nearing completion.

Overall, capital spending more than doubled from the previous year, to reach $271.9 million in 1980. About 90 per cent of the total was expended by our Resources Group.

Also during the year, we conducted a massive, Company-wide search for opportunities in addition to those identified in our long-range plan. It resulted in a series of exciting new initiatives designed to position Suncor as a much larger supplier of energy and petroleum products. Decisions had been expected on a number of these items by year end but were postponed pending a response to our request for the synthetic crude reference price.

Canadianization Plans Uncertain

Another initiative held up by the pricing question was a public issue of Suncor common stock. Suncor has, in the past, expressed complete agreement with the need for increased Canadian ownership of energy resources. We are prepared to support the overall objectives of Canadianization contained in the National Energy Program with firm action.

As it is, we have an undertaking to the federal government that in the range of 15 to 20 per cent of our common shares will have been distributed in Canada by the end of 1983. A prospectus has been prepared and underwriters selected. We were, in fact, poised throughout most of 1980 to enter the market, waiting only for clarification of oil sands pricing which investors should have before purchasing our shares, given the impact of this pricing on our earnings.

However, our desire to Canadianize extends well beyond this commitment. Suncor was in the process of examining ways to increase Canadian ownership when the National Energy Program was announced. The oil sands pricing terms contained in the Program forced us to re-evaluate our position because those terms resulted in an estimated $2 billion reduction in the market value of our Company. Once the pricing question has been satisfactorily resolved, we are planning to increase Canadian participation in our Company substantially.

The Human Factor

Despite the discouragements of the oil sands pricing issue, our personnel maintained a professional and productive attitude in 1980. Significant additions to staff were made to gear up our Company for an increased role in energy development. Improved goal-setting and performance evaluation programs were instituted to ensure that effort and responsibility are rewarded. Suncor has, I believe, perhaps the most effective team of people in the industry, one of the main reasons for our enhanced performance in 1980.

Outlook

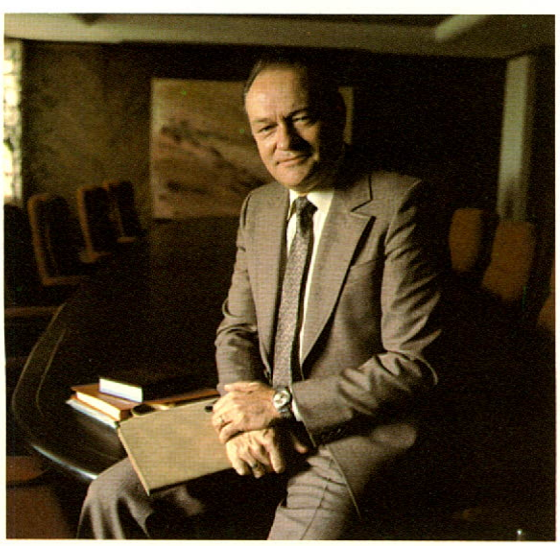
So much depends upon our synthetic crude oil price that at this time, almost nothing definitive can be said about future plans. If the current pricing is not changed, Suncor's 1981 pre-tax income will be reduced by about $250 million from the levels we would have attained with the synthetic crude reference price. Obviously, anticipated capital spending plans would have to be cut to the bone.

In addition to the oil sands pricing issue, we must also consider the impact of the National Energy Program tax changes and Canadianization requirements. The new Petroleum and Gas Revenue Tax, set at eight per cent of production revenues less operating costs, comes directly out of our earnings. We estimate that this item will reduce 1981 earnings by about $20 million from what they would have been otherwise, based upon the National Energy Program's pricing for Suncor.

Depletion allowances for the exploration and production of provincial lands will be phased out. These sizeable tax deductions would be replaced by federal grants payable only to Canadian-controlled companies—a provision which would have the effect of substantially increasing the effective tax rate for non-qualifying companies. Under the National Energy Program, the federal government would also acquire a 25 per cent interest in all rights to Canada lands (those outside provincial jurisdiction) without payment of compensation. A minimum Canadian ownership level must be met to produce from these lands.

Another concern is the lack of agreement between Ottawa and the producing provinces. We cannot continue to commit financial resources to long-term energy projects when the fundamental issue of revenue-sharing is still a matter of debate. Surely there is enough revenue derivable from oil and gas to satisfy the legitimate needs of governments and the oil industry.

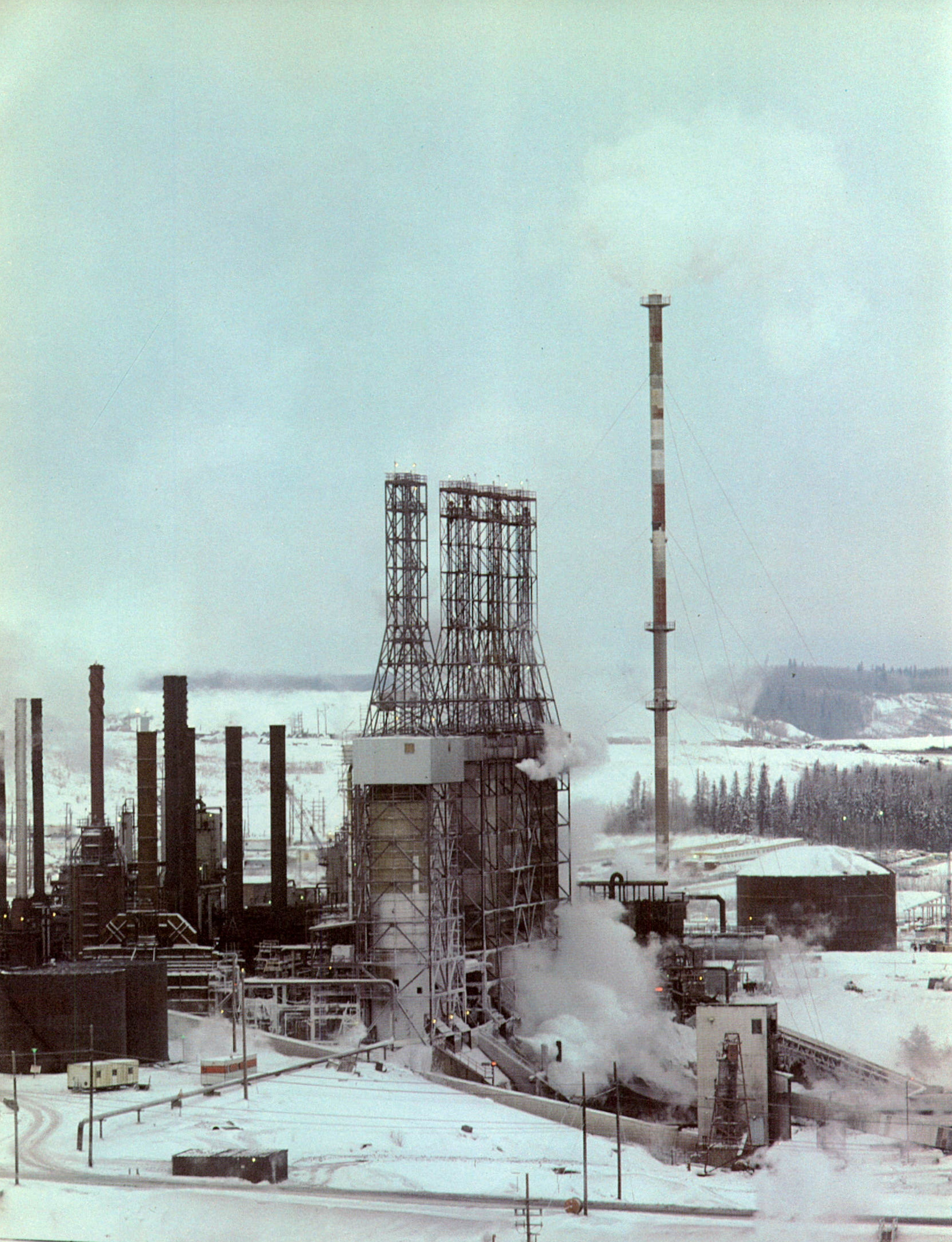
Despite the shocks and uncertainties of the past year, we remain committed to Canada. Given a reasonable regulatory environment and the synthetic crude oil reference price for all oil sands production, we believe Suncor will make a significant and growing contribution to Canadian oil and gas supplies.



Ross A. Hennigar

Ross A. Hennigar
President and
Chief Executive Officer

March 5, 1981



Suncor's Case for a Fair Oil Sands Price

On October 28, 1980, Ottawa released its new National Energy Program (NEP). In it, the price for Suncor's synthetic crude from the oil sands was slashed from $38 per barrel to $16.75, jeopardizing the future financial stability of our Fort McMurray project.

The Background

Suncor's oil sands project in the Athabasca region of Alberta was launched in 1963 under the name of Great Canadian Oil Sands Limited (GCOS). Once production began, in 1967, we received the western Canadian oil price which was closely related to world market prices. At that time, prices were low and we operated at a loss for six successive years. It was hardly surprising: GCOS was the first commercial scale project to exploit the oil sands. Every step was a pioneering one, the consequences often unknown, with nature in the wilds of northeastern Alberta a merciless enemy.

In late 1973, as the world price began to rise sharply, the Canadian government moved away from the world price and set a Canadian price for all domestic production. GCOS received this price which was the same one granted for much lower cost conventionally-produced oil. We therefore asked for a higher price to reflect our costs and the experimental nature of our project. However, we continued to receive the domestic price and our oil sands operations therefore remained marginal through to 1979.

The technical viability of oil sands mining having been demonstrated, the Syncrude project was born. In recognition that it would never succeed under the same terms as GCOS, Syncrude was granted world prices in 1975. In November 1978, the federal government agreed to apply the same price to Suncor and we were therefore able to undertake a 25 per cent expansion of our operations at a cost of $185 million. An agreement was signed with Ottawa, and world prices for our synthetic crude became effective on April 4, 1979 following Alberta government approvals.

World prices then moved quickly to unanticipated levels due to the OPEC cartel. Suncor's agreement with Ottawa provided that the federal government could review the terms under certain conditions. On March 28, 1980, Suncor received official notification that the agreement was in fact being reviewed. Suncor had already acknowledged that a review was appropriate in a submission to Ottawa made the preceding January.

On October 28, 1980, the federal government released its National Energy Program which cut the price for Suncor's existing oil sands production by more than 50 per cent, effective November 7, 1980. Syncrude was awarded a new reference price of $38 per barrel for its entire output, more than twice the Suncor level. Suncor's expansion volumes were segregated and given this reference price, thus creating a "mixed" price for Suncor once the expansion increment comes on stream.

In summary, our oil sands pricing is a story of abrupt changes. When world prices were low, we were given them. When the world price rose, we were given a lower price. This cycle has occurred twice, and both times an enormous gap was created between us and Syncrude, our oil sands producing neighbour. Under the NEP, as it now stands, this gap will never be closed.

The Financial Consequences

The October 28 price effectively returned our oil sands project to a marginal financial position.

In 1981, the Fort McMurray plant will show an estimated return on capital employed of a little more than two per cent. Cash costs excluding expansion-related expenditures will exceed cash

Suncor's oil sands plant near Fort McMurray, Alberta.

flow by more than one dollar per barrel, totalling $13 million. Thus, in the eighteenth year of our oil sands project, when profitable operations should be confidently expected, we will not generate enough cash flow to cover ongoing expenditures. If we can hold cost increases to general inflation plus four per cent, our after tax-rate of return will average about seven per cent over the life of the project. This return is less than the expected rate of inflation and comparable to the yield on a no-risk savings account. The seven per cent estimate is optimistic, since inflation in our industry in northern Alberta has historically exceeded national levels by more than four per cent.

The risks in oil sands mining are, however, very considerable. Under the NEP the balance between our revenues and expenses becomes even more precarious and relatively minor incidents can be sufficient to wipe out the cash surplus built up over a year or two. For example, the projected cash surplus from 1991 to 1995 would amount to just 19 days of production. A relatively minor leak in our natural gas pipeline in late 1980 resulted in a loss equivalent to 18 days of production, despite around-the-clock repair work.

In our view, Suncor's oil sands project may not be economically viable with the current pricing formula.

Significant Production Lost

Under the NEP, Canada will lose at least 90 million barrels of high grade synthetic crude oil, and perhaps much more.

Not all the oil sands on the 2 456 hectare lease where our plant is located are mineable. In some places, the overburden is too thick, the bitumen content of the sand is too low and the fine clay content is too high. The mineable area is determined by a complex procedure which relates these and many other factors. The result is an assessment of what is economic to produce and in this assessment, price is paramount.

Following the rapid price increases of 1979, we launched a study to determine if additional oil sands could be mined economically. The conclusion was that another 90 million barrels previously not worth producing could be recovered at significantly higher costs, which would extend the life of our project by about five years.

When the NEP was released, this additional production became uneconomical once again. It is possible that other areas scheduled for mining may also prove to be uneconomic under the NEP.

The NEP's price for Suncor, if maintained, would also put a halt to other oil sands related investments, one of them a project to recover bitumen from sludge. We currently extract about 90 per cent of the bitumen from oil sand; much of the remainder is trapped in sludge at the bottom of the tailings ponds. A commercial scale plant could reprocess this material, adding as much as 40 million barrels to our reserves. Much higher prices would be needed to justify the development and operation of the necessary plant.

For this total of 130 million barrels of reserves, the decisions must be made soon. The additional mineable area, once bypassed, will become prohibitively expensive. The sludge, which will begin to be moved in 1984 to make way for extension of the mine, will never be accessible again. Under the NEP, this oil will have to be replaced with imported crude for which Canada will have to pay a price much higher than would have been needed by Suncor for Canadian production.

Suncor Singled Out

Suncor's treatment in the NEP is unique. We are the only company which has not received a price treatment related to production costs. In every other case, prices are determined by the nature of production—whether conventional, synthetic crude or heavy oil (labelled tertiary production in the NEP). Suncor is the only company to receive a "mixed" price consisting of the conventional crude oil price for pre-expansion output plus the reference price for expansion volumes.

Why this unique treatment? Perhaps it was assumed that because Suncor's initial capacity was developed when costs were lower, conventional prices should therefore apply to this segment (despite the fact that oil sands mining is much more expensive and riskier than the process of conventional oil exploration and production). In fact, if we equate Suncor and Syncrude after expressing historical figures in terms of their present values, Suncor's unrecovered investment on a per barrel basis is higher than Syncrude's. This result reflects the years of losses and the continuing capital demands of our operation.

Furthermore, the initial capital costs of constructing the plant are of little significance compared to ongoing operating expenses, either for Syncrude or Suncor. We estimate that 90 per cent of the cash costs for our oil sands project are yet to be incurred. Only $2 billion has been expended of the $20 billion in total spending necessary to realize the potential production of our oil sands project.

Our operating expenses per barrel are, if anything, higher than Syncrude's because our technology is older. Our costs are subject to the same inflationary pressures and, as noted, most of these expenses are in the future. Yet Suncor is expected to operate its current capacity at less than half Syncrude's price. Our oil sands plant was, in effect, a massive 17-year "R & D" project of enormous benefit to Canada and other potential producers, but this leadership has been recognized by a price treatment substantially worse than those who have followed our lead.

The Solution: Parity with Syncrude

There are solid reasons for parity with Syncrude. As already noted, our unrecovered investment per barrel is about the same. Costs are similar. We are competing in the same, very competitive markets for people, materials and housing.

Parity with Syncrude would mean we would receive the synthetic crude reference price adjusted annually by the rate of increase in the Consumer Price Index. With these terms, our after tax rate of return over the life of the project would be about 11 per cent—not enough to compensate for the risk, compared to other investments, but sufficient at least to ensure financial stability. We believe that adjusting the reference price by the rate of national consumer inflation is obviously inadequate, given the historical fact that cost escalations for oil exploration and production have been consistently much higher.

Ending the Drift

Canada is drifting toward dependence on foreign oil. The cost of this dependence will be high. Foreign oil has mounted rapidly in price, its supply is uncertain and its availability may increasingly depend upon agreement with the policies of exporting countries. One positive step which can be taken immediately to help alleviate this situation is to apply the synthetic crude oil reference price to all of Suncor's oil sands production. This will increase Canadian reserves, facilitate new energy projects and signal a commitment to fair and equitable dealings for those who invest in Canadian oil and gas development.

March 5, 1981

Financial Review

EARNINGS—Earnings before extraordinary gains were $306.4 million for 1980, an increase of $136.6 million over 1979. The bulk of the increase was due to higher synthetic crude oil selling prices and production. Of the factors contributing to the remainder of the increase, strengthened gasoline and middle distillates margins were the most significant.

Exploration, production and resources development—Pre-tax operating profit from this segment declined by $0.2 million to $34.9 million.

Revenues rose by $27.2 million or 22 per cent. Higher crude oil and natural gas selling prices arising from legislated price increases ($29 million) were partially reduced by lower crude oil sales volumes ($3 million).

Expenses were up by $27.4 million or 30 per cent. Factors contributing to this increase were royalties on the higher revenues ($11 million), additional depreciation and depletion charges arising from continuing growth in the investment base ($6 million), and increased research and development costs, provincial taxes, and other operating expenses.

Oil sands—Pre-tax operating profit from this segment increased by $157.9 million to $296.4 million.

Revenues rose by $251.9 million or 73 per cent. Of this amount, $218 million was due to higher synthetic crude oil selling prices and $34 million arose from a 10 per cent increase in the production of synthetic crude oil. 1979 production was depressed by the biennial maintenance shutdown and a major fire, each of which resulted in about one month's lost production.

Expenses were $298.9 million, up $94.0 million or 46 per cent over 1979. This increase was partly caused by royalties on the higher revenues ($50 million), additional maintenance expenses ($14 million) and higher depreciation charges on increased capital investment ($6 million). The remainder of the increase arose because of higher operating expenses reflecting, in part, increased production.

The rate of cost inflation experienced by the segment is substantially higher than the general rate of inflation indicated by the Consumer Price Index, largely because of high pressure of demand for products and services by the oil and gas industry in western Canada, especially in the Fort McMurray area of Alberta.

Refining, petrochemicals and marketing—This segment's contribution to the Company's pre-tax operating profit increased by $31.5 million to $115.5 million.

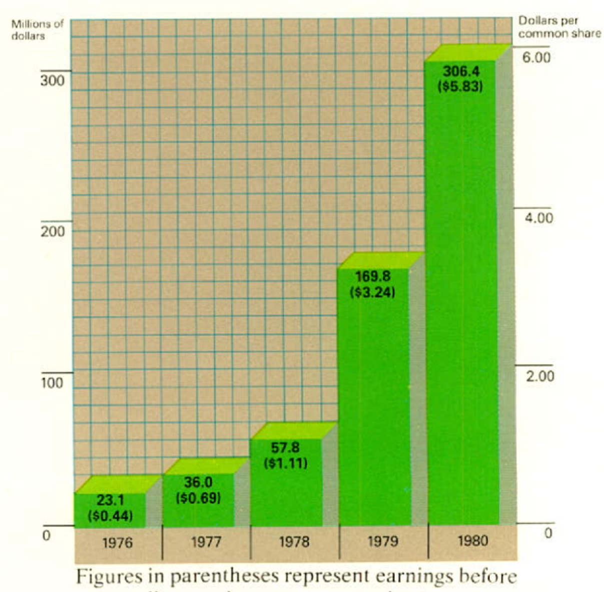
Revenues rose by $147.0 million or 21 per cent. This change was primarily due to refined products price increases ($148 million) of which petrochemical price increases were $14 million.

Expenses were up by $115.5 million or 19 per cent. Crude oil and raw feedstock costs rose by $59 million primarily as a result of purchase price increases. Other major factors were the petroleum compensation charge—formerly the federal petroleum levy—(up $23 million), transportation costs (up $10 million), and federal sales tax on the revenue increase ($4 million). The remaining cost and expense increases were primarily due to the effect of inflation on refining, marketing and administrative operations.

Income taxes and other items not allocated to segments—Interest income before tax rose by $19.3 million as a result of higher short-term investments and interest rates.

Income taxes were up $77.2 million mainly as a result of the increase in pre-tax profits. The effective tax rate rose from 33.6 per cent to 34.8 per cent primarily reflecting the five per cent federal income tax surcharge.

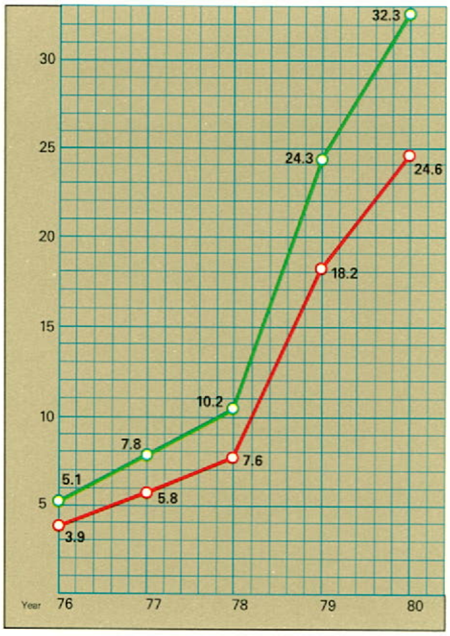
Earnings before extraordinary gains



Figures in parentheses represent earnings before extraordinary gains per common share.

CHANGES IN FINANCIAL POSITION—Funds generated by operations in 1980 were $165.6 million higher than 1979, primarily reflecting the increase in earnings. Purchases of properties, plant and equipment were $271.9 million in 1980, an increase of $139.1 million, or more than double the 1979 level. Major projects included the oil sands plant expansion ($98 million in 1980 vs. $30 million in 1979) and an accelerated exploration and production land acquisition and drilling program. Capital spending in the exploration, production and resources development segment was up $45.6 million or 71 per cent.

Working capital grew by $130.2 million in 1980. This was attributable to higher cash, time deposits and short-term investments of $156.6 million partially offset by a decline of $26.4 million in other working capital accounts. The net effect of higher refined product selling prices and costs on accounts receivable and inventories respectively, was more than offset by lower synthetic crude oil receivables due to reduced prices, and higher expense accruals including those for the 1981 shutdown.



Rates of return

Earnings as a percentage of shareholders' equity

Earnings as a percentage of capital employed

Return on shareholders' equity is earnings as a percentage of average shareholders' equity. Average shareholders' equity is the average of total shareholders' equity (including Preferred Shares Series A) at the beginning and end of the year.

Return on capital employed is earnings as a percentage of average capital employed. Average capital employed is the average of total assets less current liabilities at the beginning and end of the year.

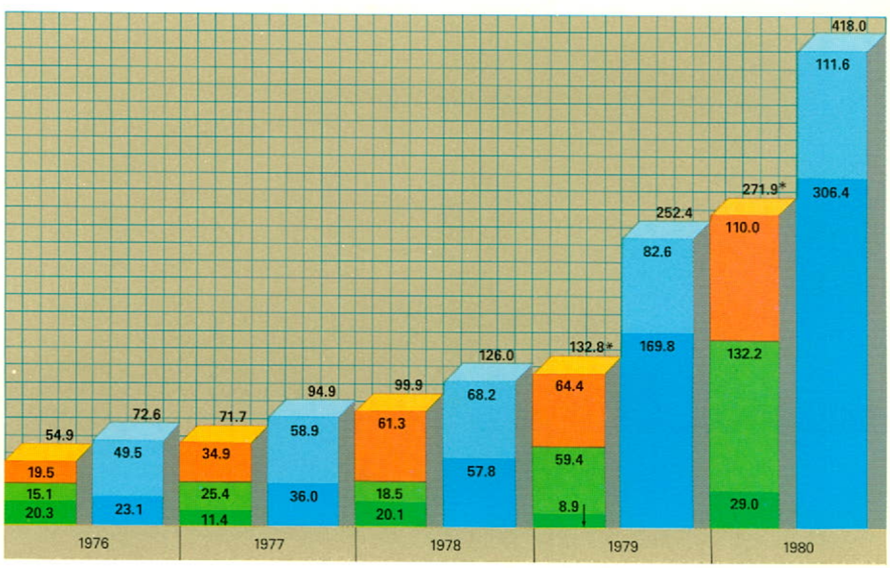
Funds from operations vs. purchases of properties, plant and equipment
(millions of dollars)

Purchases of properties, plant and equipment

- Exploration, production and resources development
- Oils sands
- Refining, petrochemicals and marketing

Funds from operations

- Other operating sources of funds
- Earnings before extraordinary gains



*Includes corporate purchases of $0.1 million in 1979 and $0.7 million in 1980.

Taxes and other government revenues

From Suncor Inc.	1980	1979
	(millions of dollars)	
Taxes other than income taxes		
Federal sales and excise taxes	$ 45.2	$ 41.8
Property taxes, production taxes and other	9.3	7.2
	54.5	49.0
Income taxes—current	86.1	34.9
—deferred	77.2	47.0
Petroleum compensation charge (formerly federal petroleum levy)	43.0	12.5
Crown royalties, less incentive credits	113.5	69.6
Crude oil, natural gas and mineral lease acquisitions and rentals	44.8	14.8
	419.1	227.8
Collected for governments		
Gasoline and diesel fuel taxes	70.1	68.4
Export taxes	55.1	41.5
	$544.3	$337.7

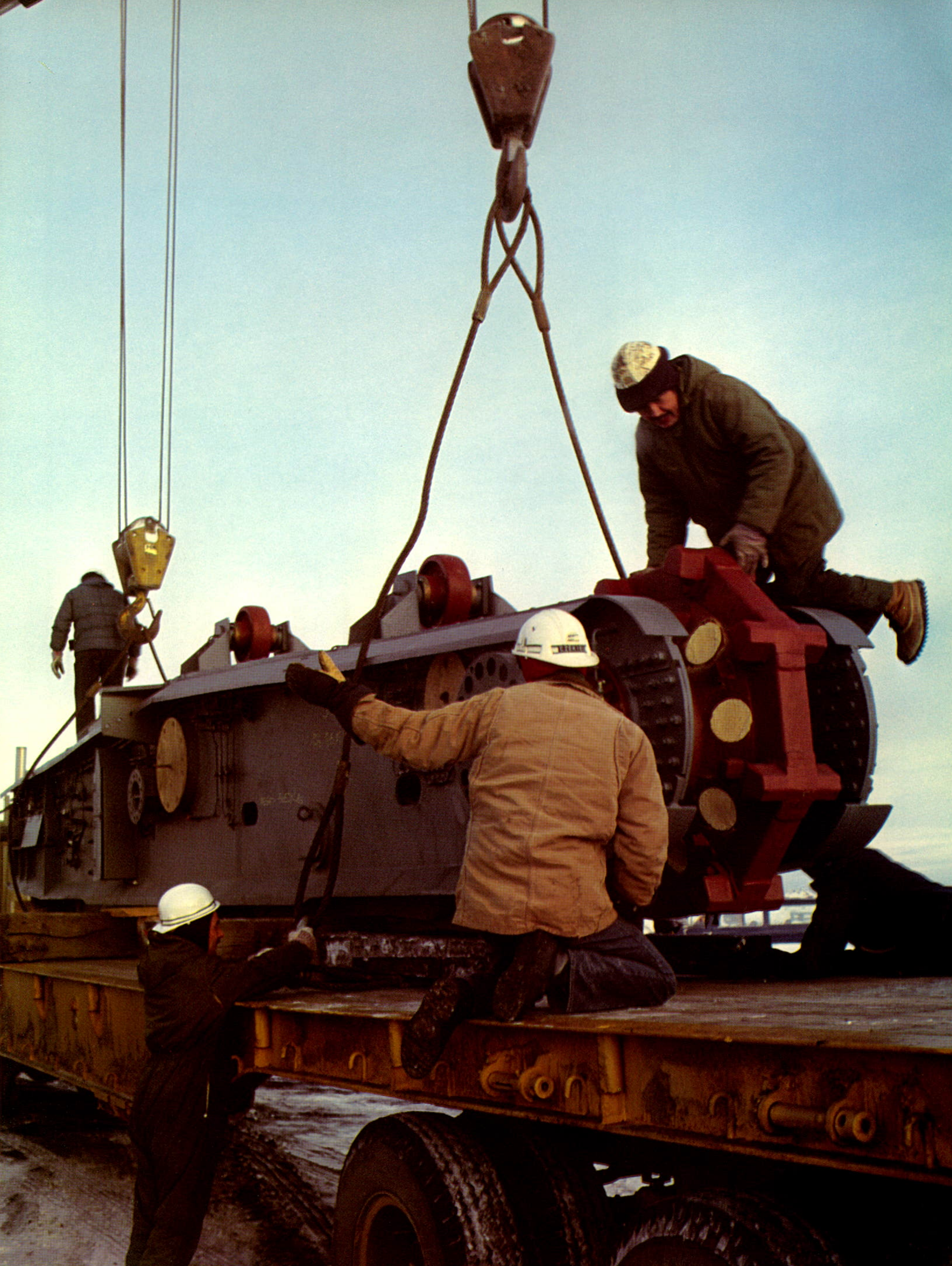
Extensive geophysical and geological work was undertaken in 1980 to identify potential locations for future exploration drilling.

Accounting for inflation

The Company's financial statements are based on historic costs and are not adjusted to account for the effect of inflation on earnings and financial position. Earnings for the year would be substantially lower if expenses reflecting outlays in prior years (primarily depreciation, depletion and amortization), were adjusted upward on account of either the declining purchasing power of the dollar or changes in specific prices. Assets acquired in prior years (principally properties, plant and equipment), would also reflect upward adjustment over historic cost figures.

No single method of accounting for inflation has yet been widely accepted in Canada. The Company has conducted extensive research, and continues to seek a method that is appropriate to its operations.

Parts for another bucketwheel begin arriving at the Fort McMurray plant site. The bucketwheel will be assembled in 1981 and used to expand the oil sands mining operation.



Report on Operations

Resources Group

Overview

The overall objectives of the Resources Group are to increase Suncor's near-term production of hydrocarbons and position the Company for a major role in future energy developments involving the frontier areas, in situ heavy oil, coal and other minerals. In 1980, we made considerable progress toward these objectives but the National Energy Program released at the end of October placed future plans in jeopardy.

The Cochrane well, 30 kilometres west of Calgary, a successful exploratory oil well drilled by Suncor in 1980.

1980 Developments

Oil production increased in 1980. Higher synthetic crude oil output from the oil sands more than offset a decline in conventional crude oil production. Natural gas sales were about the same as in 1979 despite adverse market conditions affecting the industry as a whole.

Exploration activity was sharply higher in the western Canadian provinces. Prior to 1976, our exploration assets were largely in the frontier areas. A balance has now been achieved between these opportunities and those offered by drilling in Alberta, Saskatchewan and British Columbia. Attaining this balance required a major reallocation of resources, significant additional funds, new people and new expertise. The outcome is a first-rate team in exploration and production with a sizeable and growing portfolio of properties with near and mid-term potential.

In the frontiers, significant progress

Resources Group—purchases of properties, plant and equipment

(millions of dollars)

Exploration, production and resources development	**1980**	1979
Exploration		
Drilling	**$ 26.8**	$ 13.8
Land holdings	**36.4**	10.5
Geology, geophysics and other	**7.6**	4.6
	70.8	28.9
Production		
Development drilling	**12.8**	15.9
Acquisitions and land holdings	**7.1**	6.6
Plants, related facilities and other	**17.6**	6.1
	37.5	28.6
Resources development		
In situ oil sands and minerals	**1.7**	6.9
Total*	**110.0**	64.4
Oil sands		
Plant expansion	**98.4**	29.7
Housing	**12.0**	7.4
Other	**21.8**	22.3
Total	**132.2**	59.4
Total Resources Group	**$242.2**	$123.8

*In addition, $5.7 million (1979—$4.0 million) relating primarily to exploration activities has been expensed, increasing total spending to $115.7 million (1979—$68.4 million).

was made in 1980 toward determining the potential for our Arctic Islands leases. A farmout to Dome Petroleum covering some of our Beaufort Sea interests was accomplished in 1980 so as to begin the process of evaluating these promising holdings.

Expansion of our oil sands plant located near Fort McMurray, Alberta remained on schedule. Work should be completed in 1981 with full expansion volumes expected in 1982.

Design work on two important new initiatives was completed in 1980. The first is expansion of our experimental in situ oil sands project near Fort Kent, Alberta. Work could begin in 1982, subject to obtaining a more realistic price for our synthetic crude oil as well as approvals by our partner and regulatory authorities. We also completed our planning for another in situ pilot project south of Fort McMurray. Using steam stimulation to produce crude oil, the new project could be operational in late 1981.

Outlook

Suncor's natural gas sales should increase in 1981, contrary to industry projections, primarily because of our Calling Lake South field which came on stream in early 1981, as well as a full year of production from the Stolberg field which began producing in late May 1980. However, all gas purchasers are once again expected to take less than contract minimums from existing fields in 1981.

The Neddrill 2, one of three drillships employed in the offshore Labrador area by Suncor and partners in 1980.

Wells completed

	Gross 1980	Net 1980	Gross 1979	Net 1979
Exploratory wells				
Oil	3	2	1	—
Gas	15	9	8	4
Dry	23	14	16	12
Total	41	25	25	16
Success ratio	44%		36%	
Average depth drilled (metres)	1670		1 654	
Development wells				
Oil	55	12	89	39
Gas	46	25	34	23
Dry	12	7	8	7
Total	113	44	131	69
Success ratio	89%		94%	
Average depth drilled (metres)	1 479		1 346	

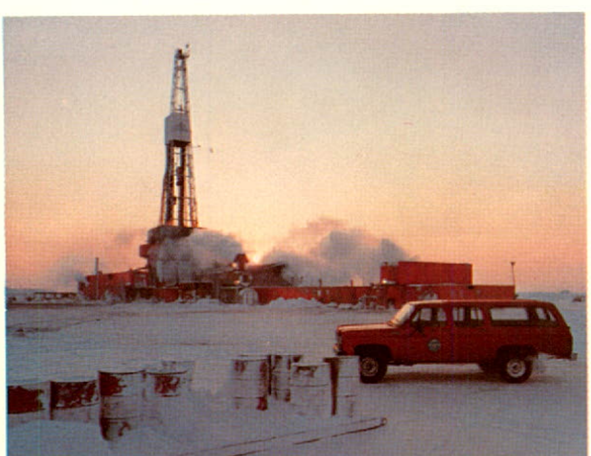
Note:

The above table does not include wells completed on Company properties under farmout agreements as no cash expenditures were incurred by the Company. During 1980 there were 11 such wells (8 exploratory and 3 development); in 1979 there were 15 such wells (5 exploratory and 10 development).

Undeveloped land holdings

(thousands of hectares)

Oil and gas	Gross 1980	Net 1980	Gross 1979	Net 1979
Western provinces				
British Columbia	**153**	**62**	151	65
Alberta	**517**	**303**	407	220
Saskatchewan	**5**	**2**	5	2
Manitoba	**—**	**—**	1	1
	675	**367**	564	288
Frontier				
Northwest Territories and Yukon	**204**	**84**	204	84
Mackenzie Delta/Beaufort Sea	**567**	**223**	567	223
Arctic Islands	**7 996**	**1 287**	8 498	3 342
Offshore Labrador (federal)	**9 018**	**902**	9 018	902
Offshore Nova Scotia	**341**	**68**	341	68
	18 126	**2 564**	18 628	4 619
Total oil and gas holdings	**18 801**	**2 931**	19 192	4 907
Minerals	**427**	**176**	192	75
	19 228	**3 107**	19 384	4 982



Courtesy of Panarctic Oils Ltd.

Whitefish G-63, drilled in 1980, confirmed a significant gas discovery on Suncor holdings in the Arctic Islands.

Conventional crude oil production will decline again in 1981, although not significantly, as a result of the normal life cycle for oil reservoirs. If the Alberta government does proceed with its program of phased cutbacks, we estimate that our conventional crude production would be cut by an additional five per cent in 1981.

Synthetic crude oil production is expected to decline marginally in the current year. A major maintenance shutdown scheduled for the late spring should be offset in part by higher production levels in the second half, due to expansion.

The question mark for the Company is the level of future capital expenditure. Sustaining the 1980 pace of exploration and production spending will require a realistic price for our synthetic crude oil. This matter is discussed in the President's Report.

Exploration Division

Suncor dramatically accelerated its search for reserves in the western Canadian provinces in 1980. In the frontier areas, Arctic Islands drilling proved successful while offshore Labrador results were generally a disappointment.

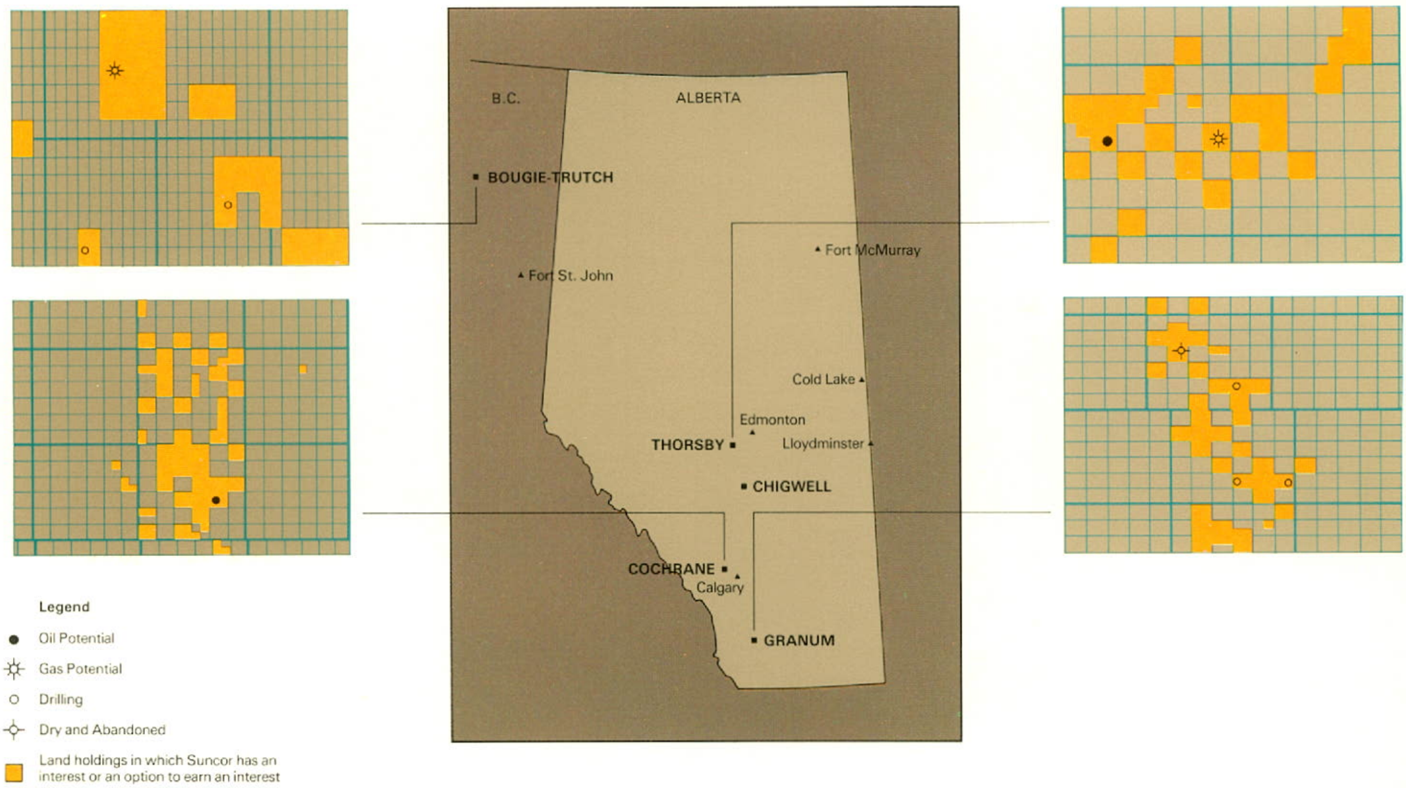
Highlights

- Capital expenditures for drilling in the provinces more than double to $22.0 million in 1980
- Eighteen gross discoveries in the provinces compared to nine in 1979
- Spending for purchases of exploration properties more than triples to $36.4 million
- Significant gas discovery at Char G-07 in the Arctic Islands
- Whitefish G-63 confirms gas discovery

Western Provinces Drilling

Suncor participated in 55 gross exploration wells in this region in 1980. Of this total, three were oil wells, 15 were gas wells, 20 wells were dry and 17 were still in progress at year end, yielding a success ratio of 47 per cent. Suncor was operator for 25 of the wells. Oil was discovered in the Thorsby and

1980 Exploratory Drilling



Cochrane areas described below and in the Chigwell area located 100 kilometres south of Edmonton.

On a net basis, 34 wells were drilled or still in progress, resulting in two oil and nine gas discoveries, 14 dry holes and nine still in progress.

Important drilling areas included:

- Cochrane area: One well was drilled in 1980—an oil discovery. This area is 30 kilometres west of Calgary. Seismic and drilling work is scheduled for 1981. Suncor interests average 50 per cent in 9 600 hectares.
- Thorsby area: Two wells were spudded in this area 60 kilometres south of Edmonton in 1980, resulting in an indicated oil well and an indicated gas well which is to undergo further tests in 1981. Seismic work is planned in early 1981 in anticipation of additional drilling. Suncor has 75 and 100 per cent interests in 5 952 hectares.
- Granum area: Four wells were spudded in this area 100 kilometres south of Calgary in 1980. Casing was installed in two of them but testing was not completed by year end. One well was abandoned and the other was still in progress. Further drilling is planned in 1981. Suncor's interests range from 50 to 100 per cent in 9 024 hectares.
- Bougie-Trutch area: Three wells were spudded in 1980 in this area 250 kilometres northwest of Fort St. John in British Columbia, yielding one gas well, one well suspended due to mechanical problems and one still in progress at year end. More drilling is planned in 1981. Suncor has interests or the right to acquire interests in 7 962 hectares.

Substantial additions were made to our exploration holdings in 1980 as a result of aggressive bidding at land sales. A total of 100 thousand gross hectares (80 thousand net) were acquired at a cost of $36.4 million, compared to just $10.5 million spent in 1979.

Key land acquisitions were in the Granum area (noted above) where interests ranging from 50 to 75 per cent were obtained in 6 500 hectares for $6.8 million; in the Thorsby area (noted above) where Suncor purchased 75 to 100 per cent interests in 5 700 hectares for $5.1 million; in the Peacock area of Alberta where a $2.3 million expenditure secured 25 to 100 per cent interests in 4 600 hectares; in the Bougie-Trutch area (noted above) where a 100 per cent interest in 2 500 hectares was obtained for $1.8 million; in the Faust area of Alberta where $1.8 million purchased 100 per cent of a 2 800 hectare parcel; and in the Donnelly area of Alberta where a 75 per cent interest in 2 400 hectares was acquired for $1.7 million. Other major additions were in the Waskahigan, Petitot, and South Helmut areas of Alberta and British Columbia.

Arctic Islands

1980 Well
1981 Well
Gas Potential
Dry and Abandoned
Land holdings in which Suncor has an interest

0 100 km 200 km

Arctic Islands Drilling

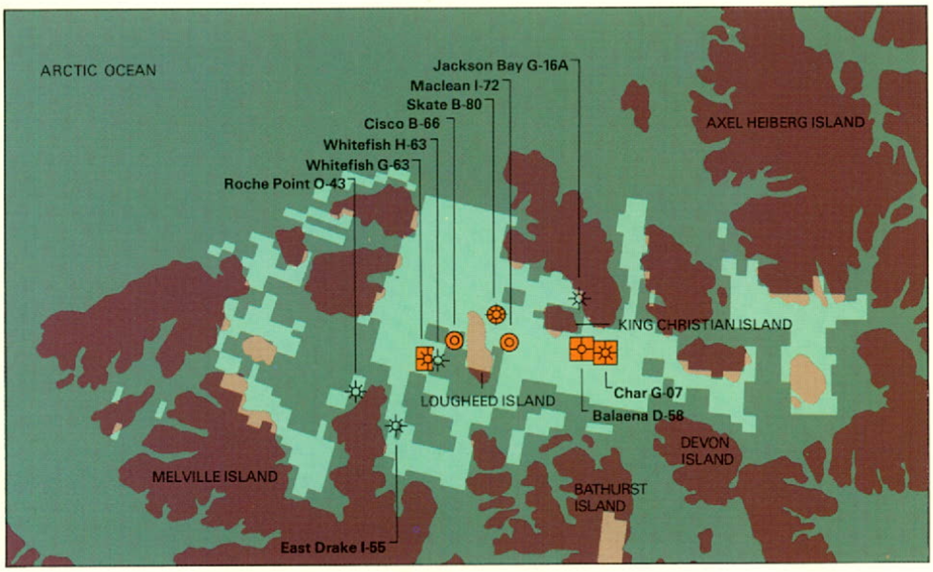
Three wells were drilled in 1980 on Suncor holdings previously farmed out to the Arctic Islands Exploration Group (AIEG).

Whitefish G-63 confirmed the 1979 Whitefish H-63 discovery. Located 40 kilometres west of Lougheed Island, G-63 tested gas at a depth of 874 to 906 metres with a flow of 210 thousand m^3 per day. A second zone from 1 672 to 1 698 metres flowed gas at 410 thousand m^3 per day with a light spray of condensate and no water. The main zone was penetrated over the interval 2 085 to 2 112 metres and production tested through tubing at flow rates up to 1.2 million m^3 per day. Condensate recovery was 75 to 100 m^3 per one million m^3 of gas. No formation water was produced during the test. Preliminary estimates indicate recoverable quantities of natural gas of 85 billion m^3.

After completion of the earning program set by the terms of agreement with AIEG, Suncor will own 20 per cent of the two federal exploration permits on which most of the Whitefish structure is located.

Char G-07 was a significant gas discovery. Located 42 kilometres southeast of King Christian Island on land farmed out to AIEG, this well tested gas at a rate of 230 thousand m^3 per day with no water from an interval of 1 566 to 1 585 metres. A lower extension of this zone, from 1 592 to 1 606 metres, flowed gas at 510 thousand m^3 per day on a drillstem test with a small amount of condensate and no formation water. A third drillstem test from 1 675 to 1 680 metres flowed at a rate of 50 thousand m^3 per day with recovery of a small amount of oil from a separate hydrocarbon zone.

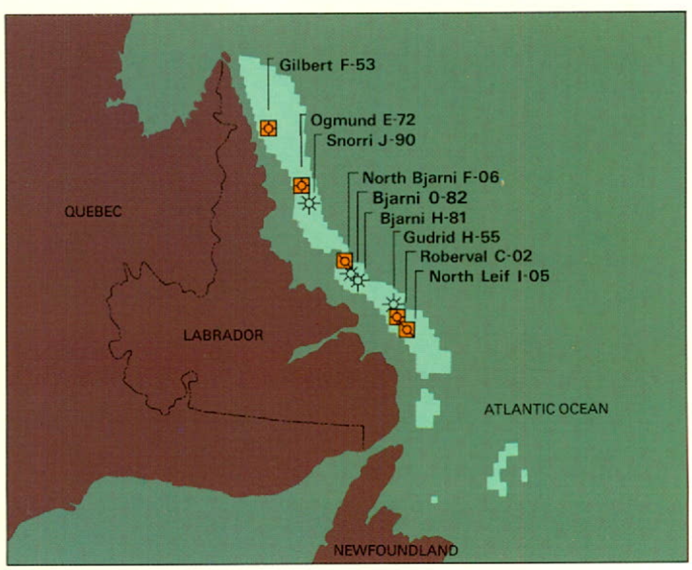
Suncor's interest in Char will be 11.6 per cent following completion of



Offshore Labrador

1980 Well
Gas Potential
Dry Well
Suspended
Land holdings in which Suncor has an interest

0 200 km 400 km 600 km



the AIEG earning program.

The third well, Balaena D-58, also showed hydrocarbons but the quantities are not sufficient to warrant commercial production. Located 16 kilometres southeast of King Christian Island, it produced small quantities of medium to heavy crude oil and no formation water from the interval 407 to 416 metres. A second zone tested at the interval 1 667 to 1 676 metres flowed gas at 80 thousand m^3 per day with a small amount of light gravity crude.

Three exploratory wells are being drilled on AIEG/Suncor interests in 1981, all offshore of Lougheed Island. The first well, Cisco B-66, is located 18 kilometres offshore, west of the Island and about 24 kilometres northeast of Whitefish G-63. The projected total depth is 3 210 metres. Maclean I-72 is 24 kilometres offshore, east of Lougheed Island. The projected total depth is 2 700 metres. Skate B-80 is 19 kilometres offshore, northeast of the northern tip of the Island. The projected depth is 2 000 metres. Also planned for The Arctic Islands in 1981 are a 500 kilometre seismic program and an ice movement study using instruments at six locations in the Norwegian Bay area.

Skate B-80 found gas in mid-February 1981. Although mechanical problems during the test restricted the flow rate to 30 thousand m^3 per day, the test results taken in total indicate a new gas discovery. The interval tested was 872 to 877 metres; drilling was continuing to test deeper zones. The tested formation is the King Christian Sand which has yielded a number of other gas discoveries.

The $48 million committed to exploration by AIEG under the farmout agreement will be fully expended by the end of the first quarter of 1981 at which time the earning program will be completed. At that time, Suncor will have interests of 14, 13 and 11 per cent respectively in the three 1981 wells.

Offshore Labrador Drilling

The Labrador Group, in which Suncor has a 10 per cent interest, employed three drillships to undertake operations at eight locations in 1980. There were no discoveries.

Gilbert F-53, 60 kilometres northeast of Saglek, was re-entered and drilled to a depth of 3 605 metres before being plugged and abandoned. Only minor traces of hydrocarbons were found.

Roberval C-02, a new well 150 kilometres northeast of Cartwright, was drilled to a depth of 2 823 metres, plugged, and abandoned. An attempt was made to plug and abandon neighbouring Roberval K-92 which had been drilled and suspended in 1979 but bad weather and mechanical difficulties prevented completion of the work.

Ogmund E-72, a new well 140 kilometres northeast of Nain, was drilled to a depth of 3 094 metres, plugged and abandoned.

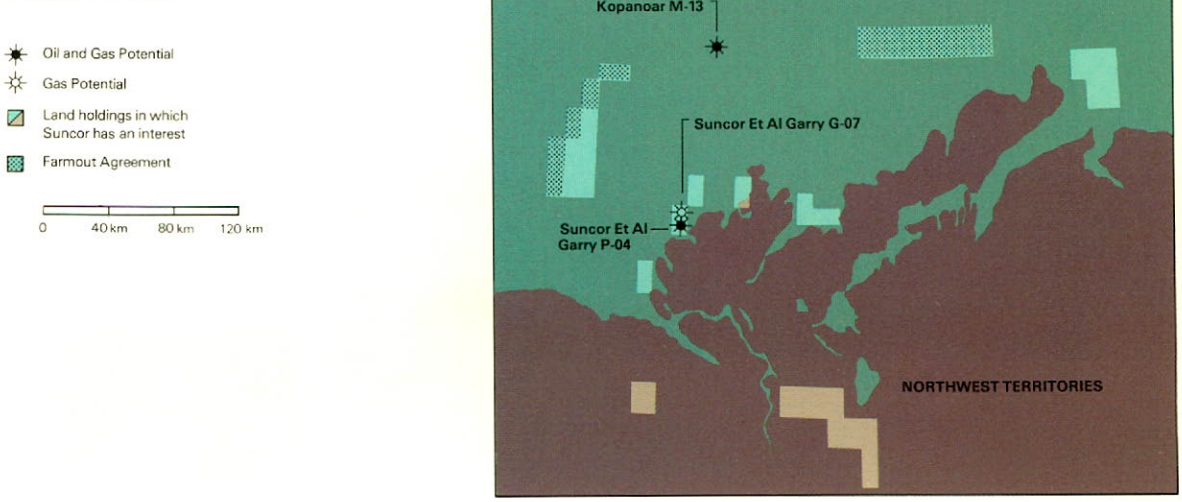
Bjarni O-82 was re-entered for further testing. It was drilled in 1979 to a depth of 2 650 metres and an inconclusive initial drillstem test in the interval of 2 362 to 2 373 metres yielded gas at a flow of 2 000 m^3 per day and condensate at 10 m^3 per day. Technical problems prevented the group from obtaining a complete test of the well in 1980 and it remains suspended.

Two other wells were spudded and suspended. North Leif I-05, 140 kilometres northeast of Cartwright, was drilled to a depth of 423 metres and casing was run into the hole. North Bjarni F-06, 160 kilometres east of Hopedale was drilled 423 metres and casing was run. Further drilling at these locations is considered likely.

Finally, Verrazano L-77, 234 kilometres southeast of Cartwright, which was drilled and suspended in 1976, was plugged and abandoned.

Seismic work was conducted in the offshore Labrador area in 1980. Operations started late but 2 153 kilometres

Mackenzie Delta/
Beaufort Sea



of data were gathered by year end. Biological studies were also continued to help assess the ecological impact of exploration and development.

Beaufort Sea Farmout

To initiate work on our extensive Beaufort Sea holdings while conserving funds for an expanded program in the western provinces, Suncor signed a farmout agreement in early 1980 with Dome Petroleum. The agreement covers 245 000 gross hectares in two main areas about 80 kilometres distant from, and on either side of, Dome's 1979 oil discovery at Kopanoar. Suncor's interests in the two blocks are 27.5 per cent and 50 per cent.

Dome agreed to undertake extensive seismic work on the properties during 1980 in return for options to drill up to five wells. The first of these options must be exercised by December 31, 1982 and the first well commenced during 1983. Dome would earn an interest in proportion to its financial participation in the wells actually drilled. Most of the seismic data was gathered in 1980; the balance was postponed due to adverse weather and ice conditions but should be obtained in 1981.

Production Division

Our production development program brought new gas fields on stream and maintained natural gas sales at approximately 1979 levels. Conventional crude oil production was down, but less than the industry average. Gross proven reserves of both conventional crude oil and natural gas declined.

Highlights

- Capital expenditures for production development up over 30 per cent from 1979
- Crude oil production down four per cent compared to a seven per cent industry decline
- Natural gas sales about the same as last year compared to industry-wide drop of eight per cent

Reserves

Gross proven reserves of crude oil and natural gas liquids declined by 12 per cent to 10.3 million m^3 in 1980. Additions to gross reserves in 1980 amounted to 142 thousand m^3. The most important additions resulted from development work in the Ferrier field about 175 kilometres northwest of Calgary and in the partial addition of Fort Kent reserves.

Gross proven reserves of natural gas fell by 5 per cent to 13.3 billion m^3 in 1980. Additions to gross reserves in 1980 totalled 525 million m^3. The largest additions resulted from development work in the Pouce Coupe area 500 kilometres northwest of Edmonton and the Mink area, 65 kilometres south of Fort St. John, British Columbia.

Approximately 62 per cent of Suncor's gross proven conventional crude oil reserves are located in Alberta as are 81 per cent of gross proven natural gas reserves.

Production

Gross daily production of crude oil and natural gas liquids averaged 2 569 m^3 in 1980, down about four per cent from 1979. The total includes both conventional and in situ oil sands but excludes synthetic crude oil mined from the oil sands.

Production declined largely due to maturing of reservoirs as well as technical problems encountered at Bonnie Glen, one of our most important fields. The Bonnie Glen difficulties were largely surmounted by year end. Drilling programs in a number of producing fields enabled Suncor to limit overall production decline.

Gross daily natural gas sales were 1 717 thousand m^3, approximately the same as in 1979. Two new fields prevented a decline—South Rosevear which began producing in late 1979 and Stolberg which came on stream in May 1980. These additions helped to offset reduced sales from fields already in production. Pipeline companies cut their purchases below contract minimums due to oversupply problems including weakness in the U.S. export market and sluggish domestic demand, factors which accounted for an eight per cent industry-wide sales reduction.

Overall, in 1980, 65 per cent of Suncor's gross crude oil production, including natural gas liquids and heavy oil, came from Alberta as did 90 per

Gross production of conventional crude oil and natural gas liquids

(thousands of cubic metres)

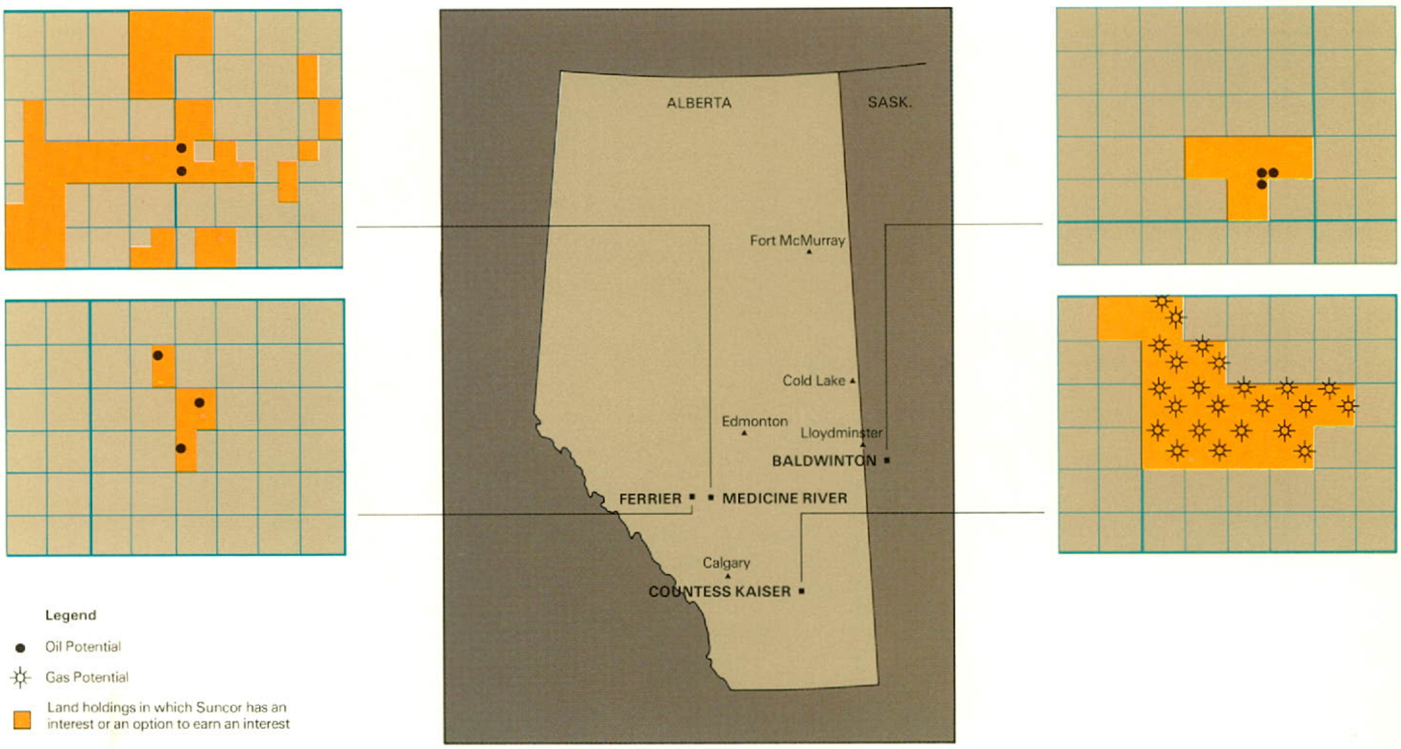
Alberta	1980	1979
Bonnie Glen	96	111
Medicine River	89	81
Swan Hills	81	86
Pembina	32	37
Fort Kent	31	23
Mitsue	30	33
Other	250	264
	609	635
Saskatchewan		
Steelman	73	79
Oungre	47	49
Other	135	131
	255	259
British Columbia	52	65
Manitoba	24	24
	940	983

Gross natural gas sales

(millions of cubic metres)

Alberta	1980	1979
Rosevear	105	112
Portage	90	82
Calling Lake	35	45
Ghost Pine	25	31
Other	311	283
	566	553
British Columbia		
Inga	19	28
Other	36	47
	55	75
Saskatchewan	7	12
	628	640

1980 Development Drilling



cent of gross natural gas sales.

Spending on gas gathering and processing systems to facilitate production reached $8.6 million in 1980, nearly three times the previous year's total. The largest expenditure was for the Calling Lake South field which came on stream at the beginning of 1981.

Drilling

A total of 113 gross development wells were drilled in 1980, yielding 55 oil wells, 46 gas wells and 12 dry wells for a success ratio of 89 per cent. Another 3 wells were in progress at year end.

On a net basis, development drilling amounted to 44 wells resulting in 12 oil wells, 25 gas wells and 7 dry holes with 3 wells in progress at the end of the year.

Drilling activity included:

- Countess area: Twenty-four shallow gas wells were drilled in this southeast Alberta location during a 1980 infill program on this 3 072 hectare property, bringing the total to 45 wells. Drilling on this block is now complete. Suncor has a 50 per cent interest.
- Ferrier area: Three Cardium oil wells were drilled in 1980 on this 512 hectare property 175 kilometres northwest of Calgary which was acquired at a December 1979 land sale. Another three wells are planned for 1981 including water injector wells as part of a waterflood scheme to increase production. Suncor has a 100 per cent interest.
- Medicine River area: Two oil wells and one water injector well were drilled on this 1 984 hectare property located 150 kilometres northwest of Calgary. Three more infill oil wells are planned in 1981. Suncor has a 31 per cent interest.
- Baldwinton area: Three conventional heavy oil wells were drilled in 1980 on this 1 036 hectare property 80 kilometres southeast of Lloydminster, Saskatchewan. There are now 19 wells capable of production. Suncor has a 100 per cent interest.

The remaining development wells were drilled on lands throughout Alberta, Saskatchewan and northeastern British Columbia.

Land Acquisitions

To increase our land base, we purchased 8 756 gross hectares of undeveloped production properties at Crown land sales in 1980. Total spending was $7.1 million, up from $6.6 million the previous year. Major purchases were located in the Pouce Coupe area 500 kilometres northwest of Edmonton where Suncor obtained a 100 per cent interest in 1 216 hectares; the Pine area, 190 kilometres west of Edmonton where interests ranging from 33 to 100 per cent were purchased in 2 432 hectares; and the Elk Point area, 160 kilometres northeast of Edmonton where Suncor secured a 100 per cent interest in 1 024 hectares. Development work is scheduled for all three locations in 1981.

Reserves

	Gross		Net	
	Conventional crude oil and natural gas liquids (millions of cubic metres)	Natural gas (billions of cubic metres)	Conventional crude oil and natural gas liquids (millions of cubic metres)	Natural gas (billions of cubic metres)
Proven				
January 1, 1980	11.7	14.0	8.1	10.8
Revisions	(0.6)	(0.6)	(0.3)	(0.7)
Additions	0.1	0.5	0.1	0.4
Production/sales	(0.9)	(0.6)	(0.6)	(0.4)
December 31, 1980	10.3	13.3	7.3	10.1
Probable additional				
December 31, 1980	1.7	6.6	1.2	4.8

Notes:

The above reserve estimates have been prepared by independent petroleum consultants, Kloepfer Coles Nikiforuk Pennell Associates Ltd. ("Kloepfer").

Proven reserves are those which geological and engineering data demonstrate to a high degree of certainty to be recoverable at commercial rates from known oil and gas reservoirs under existing economic and operating conditions.

Probable additional reserves are those which may be recovered from properties in the vicinity of proven reserves where there is some degree of geological, engineering or operational risk.

Royalty interests of governments and others are deducted from gross reserves to arrive at net reserves. These can vary depending upon prices, production volumes, timing of initial production and changes in legislation. Rates used are those experienced in late 1980.

The Company's Fort Kent in situ oil sands reserves have been calculated using the December 31, 1980 conventional crude oil price ($16.75 per barrel), and have been reflected in the above figures for the first time. Implementation of the tertiary oil price of $30.00 per barrel announced under the National Energy Program could result in an increase in Suncor's in situ oil sands reserves.

All proven reserves are located in western Canada. Crude oil reserves in the frontier areas have not been included as there is insufficient drilling to determine if they are of commercial size. Natural gas reserves in the frontier areas have not been included as their recovery depends upon approval and construction of adequate transportation systems to carry the gas to markets.

Kloepfer has determined the present value of estimated future net revenues from these reserves using a discount factor of 10 per cent to be $569 million. Estimated future net revenues employ December 31, 1980 prices and costs, and represent gross revenues from the estimated future production less royalties, taxes, operating costs and capital expenditures incurred in developing and producing the reserves, with no deduction for income taxes or administrative costs. Hence, estimated future net revenues do not represent future net earnings or the present market value of the reserves. These estimates are particularly sensitive to government actions with respect to selling prices, royalties and similar levies, and production levels.

Resources Development Division

This Division is responsible for developing new energy sources. In situ projects producing heavy oil from the oil sands are currently the main emphasis, followed by coal and other minerals.

Highlights

- Engineering studies completed for proposed expansion of Fort Kent in situ project
- Work begins on new in situ project
- Production at Fort Kent up 34 per cent in 1980
- Promising results from evaluation of Chip Lake coal lease

Fort Kent

Suncor is the operator and 50 per cent owner of this experimental 2 007 hectare in situ steam recovery project at Fort Kent in the Cold Lake area of northeastern Alberta. Steam and water are forced underground to reduce the viscosity of heavy oil trapped in the sand, inducing it to flow. The oil is then pumped to the surface.

During 1980, production from the Fort Kent project averaged 169 m^3 per day compared to 127 m^3 per day in 1979.

Ten delineation wells were drilled during the year to determine if reserves were sufficient to warrant expanding production to nearly 800 m^3 per day. These wells indicated exploitable oil in place exceeding 35 million m^3, sufficient to justify consideration of the expansion.

Preliminary engineering designs for the expansion have been completed, involving the drilling of 112 wells and construction of additional steam facilities at an approximate cost of more than $50 million. Agreement in principle has been reached with the nearby town of Bonnyville to use its sewer effluent as a water source for steam injection. Specialized drilling equipment will be constructed to drill six slant wells in 1981 as a test of the concept to be used in the actual expansion.

A decision to proceed with expansion of the Fort Kent project will be made in 1981. Expansion requires agreement by our partner, approvals from regulatory authorities and clarification of the federal government's new pricing policy for this type of production. Under the National Energy Program, in situ production of crude oil would receive a price of $188.70 per m^3 (about $30 per barrel), which in our view is sufficient to encourage production. However, regulations governing receipt of this price are not yet available.

New In Situ Oil Sands Pilot Project

Suncor is proceeding with a $6.7 million in situ steam recovery pilot project known as Cheecham on our 20 232 hectare wholly-owned lease 27, south of Fort McMurray. This is one of three Suncor leases considered suitable for in situ oil recovery. Ten wells will be drilled in 1981 and construction will also proceed on steam generating facilities. Steam injection could begin in late 1981.

In addition, drilling of 20 evaluation wells commenced in early 1981 on Suncor leases 84 and 85, north of Fort McMurray, to quantify the bitumen in place.

Phase one of Amoco Canada's in situ oil sands forward combustion project at Gregoire Lake, Alberta will be completed in 1981 and the decision has been made not to continue with

Steam carried in these pipes is forced underground to help in the production of heavy oil at Suncor's experimental in situ recovery project at Fort Kent, Alberta.

further phases. The recovery techniques employed proved unsuccessful. Our participation provided valuable experience and data useful to development work on our adjacent oil sands leases thereby fulfilling the original objectives of our investment in the Amoco project.

Suncor's objective in the Athabasca region is to build a commercial scale in situ project by the end of this decade if government policy is conducive to our efforts.

Coal and Minerals

Considerable progress was made in 1980 in the coal and minerals portion of our business.

Promising results were obtained from our 13-hole evaluation program at Suncor's Chip Lake property, about 100 kilometres west of Edmonton. Suncor is the owner of two coal leases totalling 6 799 hectares. Drilling has indicated the presence of good, continuous thermal quality coal seams at a depth of 100 metres to 150 metres with recoverable resources indicated at 260 million tonnes under both blocks. A preliminary mine feasibility study conducted on the larger of the two blocks confirmed favourable conditions for mechanical underground long-wall mining. This block has excellent infrastructure in that rail, highway, water and power cross its southern edge. We have yet to identify a ready market for this coal and we therefore anticipate that it could be a number of years before the property is put into production.

An additional 17 holes will be drilled in 1981 to better define the deposits. Further engineering and marketing will also be undertaken.

We participated in uranium exploration in Saskatchewan, Manitoba, New Brunswick, Nova Scotia, and the Northwest Territories in 1980. All properties are in the early exploration stages.

Oil Sands Division

The Oil Sands Division operates the world's first plant to obtain synthetic crude oil from bituminous sands on a commercial scale. The plant is located near Fort McMurray, Alberta, in the Athabasca oil sands region.

A four-step process is employed. First, overburden is removed to expose the oil bearing sands. Secondly, the sand is mined and transported by conveyors to the extraction unit. Third, bitumen is separated from the sand in the extraction plant. Fourth, the bitumen goes to the process area where it is thermally cracked into coke and distillates. The distillates are desulphurized and blended to form high quality synthetic crude oil, most of which is then shipped to Edmonton for distribution. Power and steam required for plant operations are generated on site.

Highlights

- Production up 10 per cent from 1979
- Expansion continues on schedule and within budget
- Sulphur and coke sales made
- Major maintenance shutdown planned for 1981

Production

Production of synthetic crude averaged 7 421 m^3 per day in 1980, up 10 per cent from 1979. Output in 1979 was reduced by a major fire and a planned maintenance shutdown.

There was no maintenance shutdown in 1980 and operations were reasonably stable during the year. Three events did impact on operations but only one affected output. First, an equipment failure resulted in a fire in the kerosene refiner on January 28 which took 28 days to repair. Bitumen production continued during this period and the partially refined bitumen was stored until processing resumed. The bitumen backlog was processed

Synthetic crude oil gross proven reserves

	(millions of cubic metres)
January 1, 1980	65.3
Revisions	(6.6)
Production	(2.7)
December 31, 1980	56.0

Notes:

The above reserve estimates have been prepared by independent petroleum consultants, Kloepfer Coles Nikiforuk Pennell Associates Ltd.

Proven reserves are those which are considered to a high degree of certainty to be mineable at commercial rates using current and future mining methods and December 31, 1980 prices and costs. All of these reserves are located adjacent to the Fort McMurray oil sands plant.

Gross reserves do not reflect deductions in respect of Crown and applicable sublease royalties. Since the Crown royalty rate is dependent on the rate of synthetic crude oil production, calculations of net reserves would vary depending upon assumed production rates.

The Company estimates that an additional 14 million m^3 could be added to gross proven reserves with appropriate pricing for synthetic crude oil.

and no synthetic crude production was lost.

Output slipped in July due to equipment failures in the process area. However, maintenance work scheduled in August and September was completed in July and production gains in the following two months considerably surpassed the July reduction.

Finally, on November 27, a gas leak developed in the Albersun natural gas pipeline which supplies the oil sands plant, requiring a shutdown of the pipeline which left the process area and the camp living area without fuel. Lost production amounted to the equivalent of 18 days.

On the positive side, improvements continued in operating procedures and staff training while management initiatives contributed to harmonious labour relations. A new contract was signed with the McMurray Independent Oil Workers representing most of our plant employees. The agreement covers the period from May 1, 1980 to May 1, 1982.

Overburden removal was up 60 per cent from 1979 in order to get further ahead of the mining operation. About 51 000 bank m^3 were removed on average daily for a year's total of 18.8 million bank m^3. A new $2.5 million hydraulic shovel was added to our overburden removal capacity in mid-1980 and performed well.

About 91 000 tonnes of oil sands were mined on average daily during 1980, an increase of 13 per cent from the previous year. The oil sands were generally of good quality.

Required expenditures continued to escalate rapidly. The aging of key equipment and the growing distance between the mine face and the plant as well as increasing environmental requirements have continued to push up capital and maintenance expenditures. Annual capital outlays have nearly doubled in just two years to $33.8 million in 1980, not including capital outlays due to expansion.

This new hydraulic shovel which commenced operation in 1980 added to overburden removal capacity at the oil sands plant. Overburden is removed to expose oil-bearing sands for mining.

Expanding and Improving Operations

Further progress was made in 1980 toward expansion of the plant's capacity by about 2 000 m^3 per day. The work will be completed in 1981 and expanded production will be felt throughout much of the year although testing and debugging of equipment and systems will continue into 1982 when the additional capacity should be fully realized.

As of the end of 1980, 97 per cent of the engineering and about 70 per cent of the construction had been completed. Approximately $128 million of the expansion project's $185 million budget had been expended. The work remained on schedule and within budget.

Under the new National Energy Program, expanded production will receive a price of $239 per m^3 compared to $115 per m^3 for our pre-expansion output. As noted in the President's Report, Suncor is seeking changes in the pricing for its synthetic crude.

Major elements of expansion completed in 1980 were: a fifth extraction line which separates bitumen from the sand; an additional pair of coking drums in which the bitumen is thermally cracked; an additional booster station to move product along the pipeline to Edmonton; expansion of the power plant; a large, additional bitumen storage tank. These items are either in operation or being commissioned by operating personnel.

In 1981, the emphasis in the expansion will be on the process area and mining. One major task will be the start up and incorporation of the fourth coker unit into the 24-hour operating cycle. Cokers crack the bitumen in large drums, three of which currently come on and off the line every 21 hours so that the residual coke can be removed from them. With expansion, we will need to bring four drums on and off the line for servicing in about the same time period.

In the mining area, we are adding a third "bench" or "step" into the ore body in 1981. Currently, there are two bucketwheel excavators each operating from its own bench. A third bucketwheel will be put into service on the third bench during 1981 and it is expected that there will be some debugging necessary before stable operation is achieved.

Other improvements are under way in addition to expansion. For example, construction is proceeding on a new 7 000 m^2 office building at a cost of about $9.0 million. The facility will eliminate existing temporary quarters and provide room for transfer of the Edmonton office. The decision to move the Edmonton office was made in 1980 to increase operating efficiency and improve internal communications. The transfer, affecting about 120 employees, should be completed by the end of 1981. Restaffing efforts are in progress to replace personnel not wishing to be transferred.

Examination of methods to improve operations and increase output continues. During 1981, we intend to work on developing a better sludge handling system. We also plan to construct a $4.0 million pilot plant to test recovery of bitumen from the sludge although this project is unlikely unless a more realistic price is obtained for our pre-expansion synthetic crude oil output.

More than $24 million in environmental projects were undertaken in 1980. The most important was the installation of three electrostatic precipitators (ESPs) to remove fly-ash from the flue gas of the powerhouse which uses coke-burning furnaces. The total cost was about $20 million. Once fully operational, the ESPs will remove 95 per cent of the ash and meet Alberta's clean air regulations.

Other environmental work in 1980 included: strengthening of the dikes along the Athabasca River; research on land reclamation; construction of a new separator required to handle increased effluent to result from expansion; improved leak detection systems for the pipeline to Edmonton; and installation of two additional reboilers to eliminate sulphur emissions.

Sulphur and Coke Sold

During 1980, the Oil Sands Division signed its first major sulphur sales contract and also made its first trial sale of coke, both of which are by-products of bitumen processing. Shipments began during the year.

The sulphur contract covers all current production (around 100 000 tonnes annually) plus a minimum of about 50 000 tonnes per year from on-site inventory. This should result in the sale of most of our stockpiled sulphur by the end of 1986 when the contract expires. The sulphur is being granulated by the purchaser and exported to the European fertilizer market.

The coke sale is more experimental. A Japanese company tested the blending of coke with coal and by year end, a total of about 40 000 tonnes of coke had been shipped. Although the tests are continuing, negotiations on a long-term contract have commenced. The Fort McMurray plant produces about 2 450 tonnes of coke daily of which approximately 2 000 tonnes are used on site as fuel for electrical and steam generation. About one million tonnes are stockpiled at the plant. Coke is not in demand as a fuel in Canada because of the availability of inexpensive alternatives such as natural gas and coal which have a lower sulphur content.

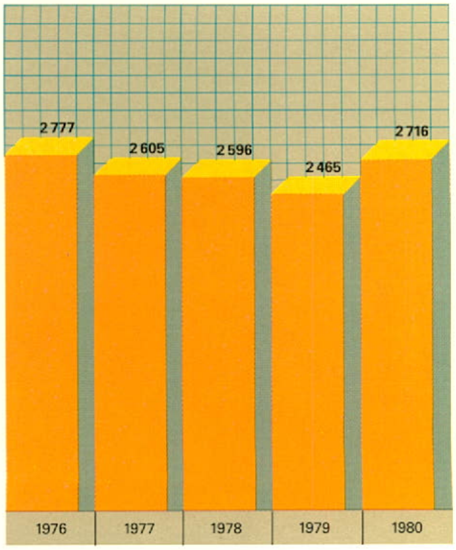
Turnaround Planned for 1981

A maintenance shutdown is scheduled for the oil sands plant starting in May 1981. It will be one of the largest "turnarounds" ever conducted in the North American petroleum industry and should enable the plant to run without major maintenance for another two years.

Because of the interdependent nature of components of the oil sands plant, the 44-day maintenance period will include 30 days of shutdown during which all normal operations except overburden removal will cease. The equivalent of about 37 days of production will be lost.

Maintenance work will require about 560 000 man-hours. Another 117 000 man-hours are scheduled for expansion and other capital projects. In total, about three times as much work will be undertaken for this turnaround as the last one, conducted in the second quarter of 1979.

Gross production of synthetic crude oil
(thousands of cubic metres)



Sunoco Group

Overview

Total revenues increased 21 per cent to $831.4 million for the Sunoco Group in 1980. Margins were firm and the Group's contribution to Suncor's pre-tax operating profits increased substantially.

Operations reporting improved performance included production and marketing of petrochemicals, gasolines, home heating oil, lubricants and specialty products. The one exception was heavy fuel oil; demand from our main U.S. customer was down from 1979 and we reduced our production by about 12 per cent. Heavy fuel oil prices were depressed and losses were recorded on sales in the domestic market.

New initiatives highlighted 1980. The most important was our decision to proceed with an upgrading of our Sarnia refinery, subject to further engineering and feasibility studies, at a preliminary estimated cost of $200 million.

The upgrading would make our refinery one of the most efficient and flexible in Canada, able to increase yields of gasolines and other key products while reducing crude oil requirements. These advantages would be accomplished using a hydrocracker and vacuum unit to reduce production of heavy fuel oil in keeping with provincial and federal government objectives. Design work is now in progress, with completion of the project expected in 1984.

Other new initiatives in 1980 included design work on refinery improvements, purchasing of a ship and the launching of an aggressive marketing program for premium leaded gasoline.

Capital spending by the Sunoco Group in 1980 was $29.0 million, up from $8.9 million in 1979.

Suncor demonstrated its commitment to independent gasoline and fuel oil retailers in 1980. Early in the year, when supplies were tight, we sacrificed sales volumes through our Company-owned and operated outlets in order to provide the volumes contracted to our independent distributors. This action expresses our support of a healthy small business community in Canada.

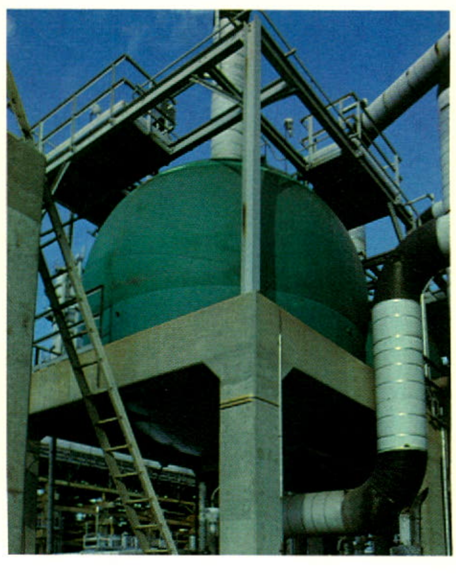
Outlook

The amount of crude processed by our refinery should remain about the same in 1981 as in the previous year, provided supplies are available. Demand for gasoline and home heating oil in Ontario and Quebec is expected to decline in 1981 but petrochemical demand should continue to rise.

Margins for all refined products are expected to hold firm in 1981.

The most serious concern is the availability of "sweet" crude oil.

Solar panels on the roof of the Sunoco Group's downtown Toronto office building were installed by Solartech, a company in which Suncor has a 15 per cent interest. The panels provide heat for hot water.



Construction began in 1980 on another reactor like the one shown opposite, to increase production of high octane gasoline and aromatics.

Alberta production is on a downward trend as major producing fields mature. If the Alberta government proceeds with phased cutbacks of production, as previously announced, we will be forced to shift domestic crude from Montreal to Sarnia and purchase additional foreign supplies on the volatile world market.

Operations

Refining

The average daily throughput of crude oil for the Sarnia refinery in 1980 was 12.4 thousand m^3. This volume was 86 per cent of rated capacity compared to 85 per cent for the previous year.

There were no significant equipment or operating problems during the year. Two scheduled maintenance shutdowns were successfully concluded. The first, in June, closed plant number two and the benzene-toluene-xylene unit for 12 days. The refinery consists of two principal plants which are independent of each other.

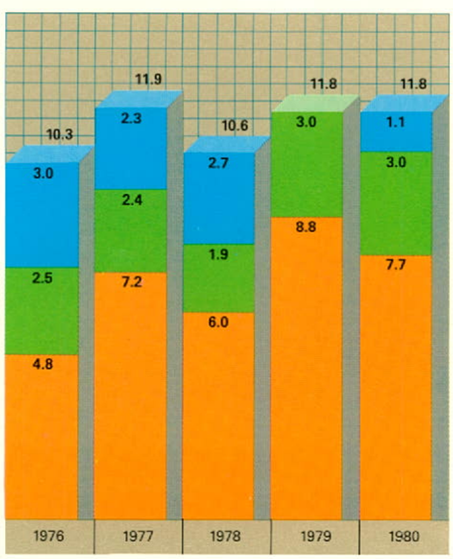
The second shutdown, in September and October, closed the alkylation unit for approximately three weeks. This unit uses hydrofluoric acid to promote the chemical reaction which converts propylene and butylene into the high-octane gasoline component, alkylate.

Burners in one of the pretreaters at Suncor's Sarnia refinery. Pretreaters remove impurities in manufacture of high-quality gasoline. Refinery operated at 86 per cent of rated capacity in 1980.

Sources of crude oil refined for Suncor account

(thousands of cubic metres per day)

- Imported
- Canadian synthetic
- Canadian conventional



No further maintenance shutdowns are scheduled for the refinery during the next two years. However, plant number two will be taken out of service for a short period of time in October 1981, to tie another reactor into the Powerformer unit. This addition will permit the production of increased quantities of high-octane gasoline and more aromatics. Work should be completed by the end of 1981 at a cost of $16 million.

The Sarnia refinery obtained its crude oil from domestic sources in 1980, including about 35 per cent from Suncor's own production. Our receipts were limited by the National Energy Board's allocation of available supply which in turn was determined by domestic production capabilities. Some of the refinery's production output was provided to another company for sale in Ontario and in exchange, this same company refined crude oil for Suncor in Montreal to supply Suncor's Quebec customers.

During 1980, we supplied our Quebec market with domestic crude to the maximum extent permitted by the National Energy Board's allocation procedures. Sunoco's deliveries from western Canada by pipeline to Montreal amounted to about 775 thousand m^3. Another 54 thousand m^3 of western crude were moved from Vancouver by ship through the Panama Canal. The remaining 130 thousand m^3 required for the Quebec market consisted of foreign oil originally from the Middle East but purchased at Caribbean transshipment terminals. Spot prices were paid for the foreign oil, costing Suncor $3.0 million in premiums not offset by the federal government's import compensation program.

In the fourth quarter of 1980, Suncor purchased 131 thousand m^3 of foreign crude on the spot market, primarily for use in 1981.

The National Energy Board will require Suncor and other refiners to accept Mexican crude oil in 1981. Suncor's allocation will amount to about 63 thousand m^3 for the year. This lower quality crude will result in the production of higher amounts of residual fuel oil which is in oversupply.

Improvements costing $8.5 million were made to the refinery in 1980, compared to expenditure of $5.2 million in 1979. Included in the total was a computerized system for blending gasolines which will contribute to product quality and reduce operating costs.

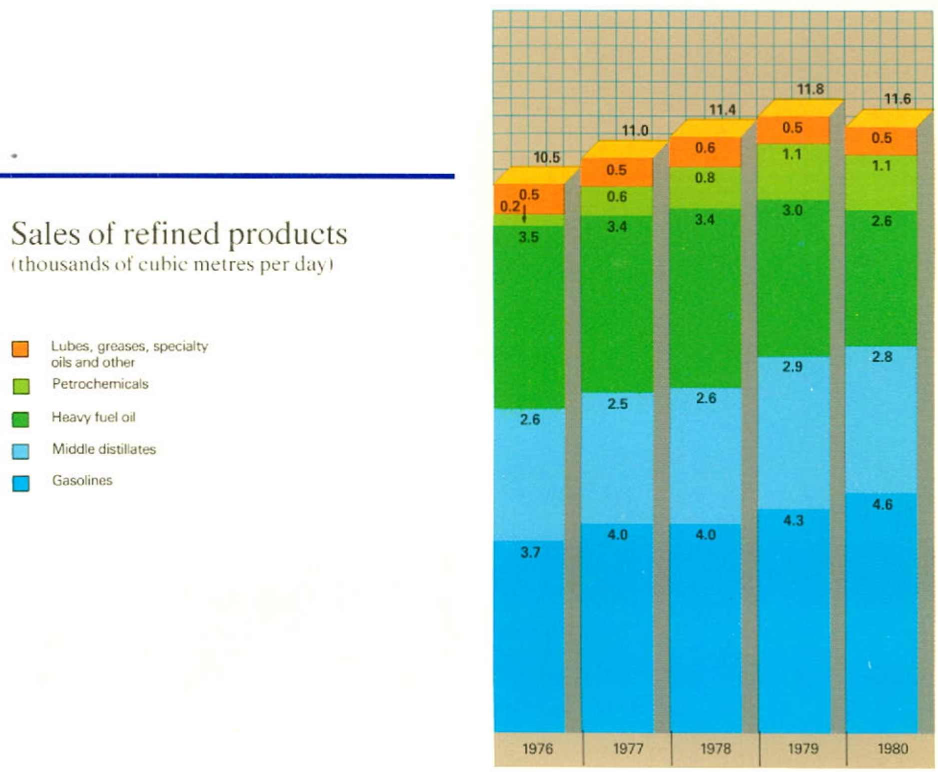
Petrochemicals

Sales revenues increased about 11 per cent in 1980 for Sunchem, Suncor's petrochemical division. A total of 424 thousand m^3 was produced, about the same as in 1979, despite a planned maintenance shutdown of the main production unit.

Sunchem manufactures benzene, toluene, xylenes and orthoxylene. These chemicals are used to make plastics, solvents, nylon, dynamite, pesticides, polyesters and paint.

Suncor's policy is to satisfy Canadian petrochemical requirements first and export the excess. Sales volumes to Canadian customers were up in 1980 despite an economic slowdown.

Sales of refined products
(thousands of cubic metres per day)



Prices were firm in Canada during the year. Due to the instability of crude oil supplies on the world market, European prices were more volatile; they began the year strongly, declined significantly during the summer, but recovered somewhat by year end.

Capital spending in 1980 emphasized improved petrochemical delivery and storage capabilities. Sunchem purchased a ship—the Suncor Chippewa—an $18 million, 20 000 tonne petrochemical tanker. The vessel should be in full service by May 1981. Construction also began on a new $2.0 million storage tank at the Sarnia refinery which will substantially increase holding capacity. Completion is expected in March 1981.

Gasoline Marketing

Our gasoline marketing network continued to outperform the industry in 1980. Revenues increased and margins improved compared to 1979.

The main challenge was the tight supply situation for gasoline in the first half of the year. A number of factors—including lower oil sands production in the preceding year and a fire at the Sarnia refinery—dictated a cutback in sales.

In response to this situation, we decided to reduce retail hours at Company-owned and operated outlets rather than limit sales to independents. We literally turned customers away. However, we did meet all our commitments to independent dealers, both branded and unbranded.

As the year progressed, the situation changed. Crude supply problems were overcome and refinery output was on the upswing. Consequently, we were able to compete more aggressively.

A number of innovations contributed to a strong second half. The most important was the decision to proceed with installation of "Blender Centres" at our self-serve outlets which had already proved successful at full-service outlets. The majority of the conversions were completed by the end of the third quarter.

Blender Centre pumps precision mix premium unleaded gasoline with regular leaded to make our Premium Leaded Blend product. Suncor is now the only gasoline marketer in Ontario to sell a higher octane leaded product; one other refiner offers it in Quebec. The Premium Leaded Blend provides a unique advantage to owners of older

The bow of Suncor's petrochemical tanker, the Suncor Chippewa, launched in 1980.

Blender Centres, a Suncor marketing initiative, offer a premium leaded gasoline blend—one reason for a successful 1980.

cars and high performance imports requiring a higher octane leaded gasoline. An intensive advertising campaign was launched to support Blender Centres in 1980.

In addition to the Premium Leaded Blend, we successfully introduced Mileage Plus, a high quality motor oil. We also added shock absorbers, belts and hoses to our line of accessories. Sales revenues from items other than gasoline increased significantly from 1979.

At year end, there were 920 service stations in the Sunoco Group system, down 30 from the year before. A number of small, unproductive locations were dropped and about $2.5 million in capital was recovered from these divestitures. All of our outlets are in Ontario and Quebec except for two in Fort McMurray, Alberta. During the year, $5.0 million was spent to upgrade and maintain the long-term viability of our gasoline retail network.

In 1981, gasoline marketing will continue to emphasize our unique Blender Centres with the introduction of an unleaded gasoline blend consisting of one-half premium and one-half regular at a price less than premium unleaded.

Home Heating Oil Marketing

The home heating oil market in Ontario and Quebec fell by about eight per cent in 1980 as consumers practised conservation and switched to other fuels. None the less, our sales volumes increased.

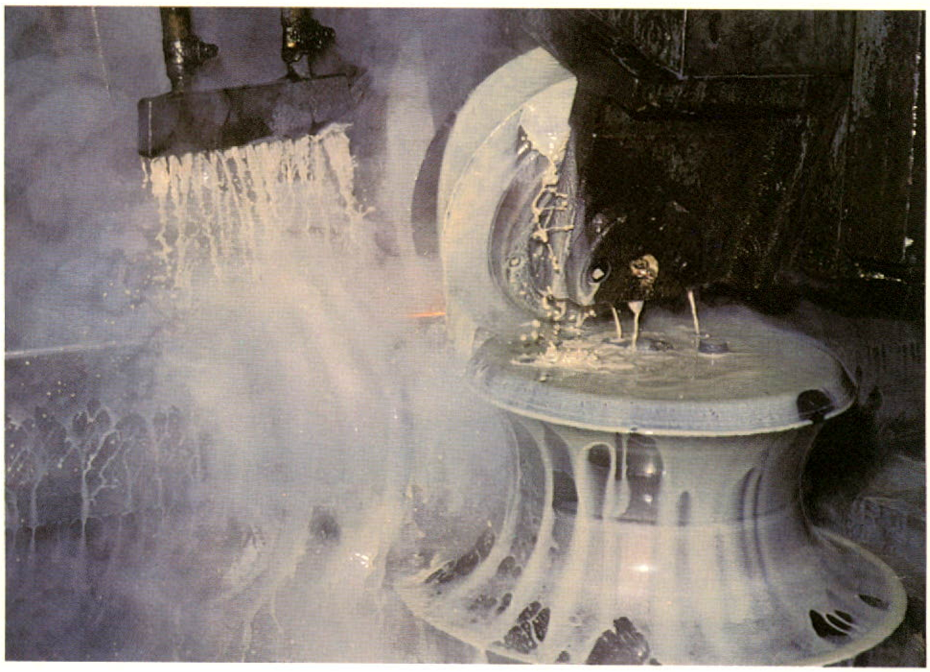
The main reason for this performance was our policy of supporting and developing a network of independent retail distributors. By year end, our products were being sold by 101 independents and 14 operating divisions of subsidiary companies.

Lubricants and Specialty Products

Sales volumes and margins remained firm for this operation in 1980. The success of our fee-for-service custom blending and packaging operation continued.

We added 30 new products to our line in 1980 including a high water base fluid — an emulsion of oil, water and other additives which is in high demand for hydraulic equipment. Other changes included a major reduction in our use of high cost imported naphthenic base stocks by reformulations where possible to make use of less expensive domestic paraffinic stocks, without loss of product quality.

A new sales office was opened in Calgary to complement the Edmonton office opened two years ago. We have had considerable success penetrating the fast-growing Alberta market. Agreement was also reached with three branded lubricant resellers in the Maritimes, thus achieving the objective set three years ago of marketing Sunoco lubricants on a national basis.



This new product, EMULSUN, functions as a coolant and lubricant in the production of steel tubing.

Suncor Inc.

Summary of Accounting Policies

December 31, 1980

The financial statements have been prepared by management in accordance with generally accepted accounting principles consistently applied. Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of numerous estimates and approximations which have been made using careful judgement. In management's opinion the financial statements have been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

Basis of Presentation

(a) *Pooling of interests*

Suncor Inc. is the continuing company arising from the amalgamation on August 22, 1979 of Great Canadian Oil Sands Limited and Sun Oil Company Limited. The amalgamation was a corporate reorganization and was accounted for in a manner similar to a pooling of interests.

The consolidated financial statements for prior years include the accounts of the predecessor companies and their subsidiaries and have been restated to reflect the effects of amalgamation, including the elimination of intercompany transactions among such predecessor companies.

(b) *Principles of consolidation*

The financial statements are prepared on a consolidated basis to include the accounts of all subsidiaries.

(c) *Elimination of crude oil revenues*

Suncor is a net purchaser of crude oil, and deems its own production to be consumed internally. Therefore, revenues from crude oil, together with oil import compensation, are eliminated against costs and operating expenses, with the following two exceptions: (i) synthetic crude oil revenues in excess of conventional crude oil prices, (ii) crude oil revenues from Alberta Crown leases. (See also note 1 to the consolidated financial statements.)

(d) *Joint ventures*

A significant part of the Company's oil and gas activities is conducted jointly with others. The accounts reflect the Company's proportionate interest in these activities.

Policies of Application to Specific Segments

The descriptions of the Company's classes of business or segments are detailed below together with their respective accounting policies.

(a) *Exploration, production and resources development*

This segment encompasses exploration for and production of crude oil and natural gas in the western provinces and frontier areas, and operation of a natural gas pipeline. In addition, in situ oil sands recovery projects, coal and uranium activities are being pursued.

The full cost method of accounting for crude oil and natural gas activities is followed. All costs incurred in searching for oil and gas reserves, including leasehold acquisition and retention costs, are capitalized. Proceeds received from disposals of properties are deducted from these costs. Capitalized costs are charged against operations through a provision for depletion, calculated on a unit-of-production basis. To calculate depletion, gas is converted into equivalent amounts of oil on the basis of relative energy content.

Wellhead equipment, gas plants and handling facilities are primarily written off over the life of estimated reserves, while support and movable equipment is depreciated on a straight line basis over an average of ten years.

Research expenditures for in situ oil sands recovery projects are expensed as incurred, except those for capital which are written off over the remaining life of the project.

(b) *Oil sands*

This segment encompasses production of synthetic crude oil from bituminous sands mined from the Athabasca oil sands in northeastern Alberta.

Mobile equipment, and mine development expenditures that significantly benefit operations of future years, are capitalized. Other mining equipment and development expenditures are expensed.

Major additions and improvements to plant capacity, productivity or environmental protection are capitalized. Other plant outlays are expensed. The cost of housing is capitalized.

Mine and plant production facilities which were capitalized prior to January 1, 1976 are depreciated over the life of reserves on a unit-of-production basis. Mine and plant production facilities capitalized after January 1, 1976 are depreciated over the lesser of their useful lives or the life of reserves. Depreciation over useful lives is on a straight line basis.

Capitalized plant production facilities and the bucketwheel excavators are primarily depreciated over the life of reserves. Conveyors and mobile equipment are depreciated on average over 3 years and rental housing over 25 years.

Deferred preproduction costs are amortized over the life of reserves on a unit-of-production basis.

Overburden removal costs, including depreciation on overburden removal equipment, are deferred. Annual amortization of these costs is based on the year's production of oil sands, the ratio of total overburden to be removed to total reserves of oil sands to be mined, and the year's removal cost per unit of overburden.

(c) *Refining, petrochemicals and marketing*

This segment encompasses the manufacture, transportation and

Lee Domony, Plant Supervisor, overlooks the Sarnia refinery where a major upgrading is planned to increase yield of gasolines and middle distillates.

marketing of petroleum and petrochemical products, primarily in Ontario and Quebec, and also sales of petrochemical products to the United States and Europe.

Depreciation is on a straight line basis. The refinery and additions thereto are depreciated over an average of 23 years, service stations and related equipment over an average of 15 years, and other facilities and equipment over 4 to 20 years.

Policies of General Application

(a) *Transfer prices between segments*
Transfers of crude oil, natural gas and refined products between segments are recorded at fair market value.

(b) *Maintenance, repairs, shutdown expense and disposals*
Normal maintenance and repairs are charged to expense as incurred. The cost of major maintenance shutdowns is estimated and accrued over the period to the next shutdown. Except for oil and gas assets accounted for under the full cost method, cost of assets sold, retired or abandoned and the related amounts of accumulated depreciation are eliminated from the accounts, and resultant gains or losses on disposals are included in earnings.

(c) *Pension expense*
The Company has a non-contributory pension plan providing retirement benefits for its employees and those of certain subsidiaries. Pension expense includes the current pension costs, the amortization of initial past service costs over 25 years, and the amortization of plan improvements over 15 years. It is the Company's policy to fund the total pension costs.

(d) *Income taxes*
Some costs and revenues may by law be deducted from or added to earnings in the calculation of taxable income in years earlier or later than actually recorded in the Company's Consolidated Statement of Earnings. The income taxes in the earnings statement are based upon the revenues and expenses actually recorded, but differ from taxes actually paid or payable. These differences are shown in the Consolidated Statement of Financial Position as deferred income taxes.

Investment tax credits are reflected as a reduction of income tax expense in the year the eligible expenditures are incurred.

(e) *Inventories*
Inventories of crude oil and refined products are valued at cost using the first-in, first-out method, which does not exceed net realizable value.

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

(f) *Foreign currency translation*
The Company applies the temporal method of accounting for the translation of foreign currency amounts into Canadian dollars.

Under this method the Company's current assets except inventories, current liabilities and long-term debt are translated at year-end rates. Other assets, other liabilities and revenues and expenses are translated at the rate prevailing when they were acquired or incurred.

Unrealized exchange gains and losses on translation of long-term debt are deferred, and amortized over the remaining repayment periods. Other exchange gains and losses are reflected in earnings.

Auditors' Report

To the shareholders of Suncor Inc.

We have examined the consolidated statement of financial position of Suncor Inc. as at December 31, 1980 and the consolidated statements of earnings, retained earnings and changes in financial position for the year then ended. Our examination was 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 statements present fairly the financial position of the Company as at December 31, 1980 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Coopers & Lybrand

COOPERS & LYBRAND
Chartered Accountants
Toronto, Ontario
January 26, 1981

Consolidated Statement of Earnings

for the year ended December 31, 1980

(millions of dollars except per share amounts)	1980	1979
Revenues		
Gross sales and other operating revenues (note 1)	$1,401.1	$1,001.8
Deduct: sales to third parties of crude oil production (note 1)	172.3	148.0
Sales and other operating revenues	1,228.8	853.8
Interest income	30.6	11.3
	1,259.4	865.1
Expenses		
Costs and operating expenses (note 1)	398.1	320.4
Selling, administrative and general	87.9	67.4
Royalties (note 2)	158.6	97.6
Taxes other than income taxes	54.5	49.0
Depreciation, depletion and amortization	84.1	67.3
Interest (note 6)	6.5	7.5
	789.7	609.2
Earnings before income taxes and extraordinary gains	469.7	255.9
Income taxes (note 3)	163.3	86.1
Earnings before extraordinary gains	306.4	169.8
Extraordinary gains (note 4)	—	3.1
Earnings for the year	$ 306.4	$ 172.9
Earnings per common share		
Earnings before extraordinary gains	$ 5.83	$ 3.24
Earnings for the year	$ 5.83	$ 3.30

See accompanying summary of accounting policies and notes

Consolidated Statement of Retained Earnings

for the year ended December 31, 1980

(millions of dollars)	1980	1979
Balance—beginning of year	$ 318.4	$ 147.6
Deduct: amalgamation expenses net of income taxes	—	1.5
Earnings for the year	306.4	172.9
	624.8	319.0
Dividends on preferred shares	1.6	0.6
Balance—end of year	$ 623.2	$ 318.4

See accompanying summary of accounting policies and notes

Consolidated Statement of Financial Position

as at December 31, 1980

	1980	1979
	(millions of dollars)	
Assets		
Current assets		
Cash, time deposits and short-term investments	$ 301.6	$ 145.0
Accounts receivable (note 5)	136.7	155.7
Inventories (note 7)	220.7	123.0
	659.0	423.7
Long-term receivables	3.2	4.5
Properties, plant and equipment (note 8)	935.8	727.6
Deferred charges (note 9)	133.3	99.8
	$1,731.3	$1,255.6
Liabilities and shareholders' equity		
Current liabilities		
Short-term borrowings	$ 35.6	$ 26.5
Accounts payable and accrued liabilities (note 5)	190.8	117.7
Income taxes	50.6	33.6
Taxes other than income taxes	22.3	15.5
Current portion of long-term debt	2.9	3.8
	302.2	197.1
Long-term debt (note 10)	47.9	69.7
Deferred revenues	20.6	9.6
Deferred income taxes	251.6	174.4
Minority interest	6.7	7.2
Shareholders' equity		
Share capital (note 11)	479.1	479.2
Retained earnings	623.2	318.4
	1,102.3	797.6
	$1,731.3	$1,255.6

See accompanying summary of accounting policies and notes

On behalf of the Board:
R.A. Hennigar, Director
D.M. McGeer, Director

Consolidated Statement of Changes in Financial Position

for the year ended December 31, 1980

	1980	1979
	(millions of dollars)	
Source of funds		
Operations		
Earnings before extraordinary gains	$306.4	$169.8
Depreciation, depletion and amortization	84.1	67.3
Deferred income taxes	77.2	47.0
Gains on disposals of properties, plant and equipment	(0.3)	(3.2)
Deferred overburden removal outlays (note 9)	(49.4)	(28.5)
	418.0	252.4
Extraordinary reduction in income taxes	—	3.1
Disposals of properties, plant and equipment	5.9	8.2
New long-term debt	—	0.2
Increase in deferred revenues	11.0	5.8
Decrease (increase) in long-term receivables	1.3	(0.7)
	436.2	269.0
Use of funds		
Purchases of properties, plant and equipment		
Exploration, production and resources development	110.0	64.4
Oil sands	132.2	59.4
Refining, petrochemicals and marketing	29.0	8.9
Corporate	0.7	0.1
	271.9	132.8
Outlays for deferred charges other than overburden	9.7	5.0
Reduction of long-term debt	22.2	7.7
Decrease in minority interest	0.5	0.4
Dividends on preferred shares	1.6	0.6
Redemption of preferred shares (note 11)	0.1	0.7
Amalgamation expenses net of income taxes	—	1.5
	306.0	148.7
Increase in working capital	130.2	120.3
Working capital—beginning of year	226.6	106.3
Working capital—end of year	$356.8	$226.6
Analysis of the increase in working capital		
Cash, time deposits and short-term investments	$156.6	$113.1
Accounts receivable	(19.0)	66.6
Inventories	97.7	14.9
Short-term borrowings	(9.1)	(10.2)
Accounts payable and accrued liabilities	(73.1)	(27.5)
Income taxes	(17.0)	(29.8)
Taxes other than income taxes	(6.8)	(5.8)
Current portion of long-term debt	0.9	(1.0)
	$130.2	$120.3

See accompanying summary of accounting policies and notes

Schedule of Segmented Data*

	Resources Group: Exploration, production and resources development		Resources Group: Oil sands		Sunoco Group: Refining, petrochemicals and marketing		Total (millions of dollars)	
Revenues and earnings For the year ended December 31	1980	1979	1980	1979	1980	1979	1980	1979
Sales and other operating revenues	$ 81.5	$ 40.8	$317.1	$129.3	$830.2	$683.7	$1,228.8	$ 853.8
Sales to third parties of crude oil production	27.9 **	38.1	144.4	109.9	—	—	172.3	148.0
Inter-segment revenues	43.1	46.4	133.8	104.2	1.2	0.7	178.1	151.3
Segment revenues	152.5	125.3	595.3	343.4	831.4	684.4	1,579.2	1,153.1
Expenses	117.6	90.2	298.9	204.9	715.9	600.4	1,132.4	895.5
Segment operating profits	$ 34.9	$ 35.1	$296.4	$138.5	$115.5	$ 84.0	446.8	257.6
Change in inter-segment profit elimination							8.9	1.4
Interest income							30.6	11.3
Corporate expense							(10.1)	(6.9)
Interest expense							(6.5)	(7.5)
Income taxes							(163.3)	(86.1)
Earnings before extraordinary gains							$ 306.4	$ 169.8
Depreciation, depletion and amortization For the year ended December 31								
Segments	$ 28.2	$ 21.9	$ 43.1	$ 33.6	$ 12.2	$ 11.1	$ 83.5	$ 66.6
Corporate							0.6	0.7
							$ 84.1	$ 67.3
Capital employed As at December 31								
Segment assets	$442.9	$335.1	$554.4	$462.4	$459.0	$349.5	$1,456.3	$1,147.0
Corporate assets and inter-segment eliminations							275.0	108.6
Total assets							1,731.3	1,255.6
Segment current liabilities	$ 49.6	$ 28.1	$ 66.2	$ 49.9	$142.2	$ 98.4	258.0	176.4
Corporate current liabilities and inter-segment eliminations							44.2	20.7
Capital employed							$1,429.1	$1,058.5

See accompanying summary of accounting policies and notes

*The Company has no foreign geographic segments. See note 6 for information on export sales.
**Excludes sales to the Alberta Petroleum Marketing Commission from April 1, 1980. (See note 1)

Notes to the Consolidated Financial Statements

December 31, 1980

1. Presentation of revenues and costs and operating expenses

(a) Reclassification

The amounts received by the Company in excess of conventional crude oil prices on sales of its synthetic crude oil production have been reclassified as revenues instead of being deducted from expenses. This reclassification, to improve the presentation and comparability of actual incurred costs, increased sales and other operating revenues, and costs and operating expenses, by $123.4 million for the year ended December 31, 1979.

(b) Alberta Petroleum Marketing Commission

From April 1, 1980 the Alberta Petroleum Marketing Commission (APMC), which purchases all conventional crude oil produced from Alberta Crown leases, no longer allowed producers to designate the ultimate purchaser of their crude oil. Consequently, the Company now recognizes these purchases by the APMC as revenues in the Consolidated Statement of Earnings. However, sales of conventional crude oil other than to the APMC, together with sales of synthetic crude oil after deducting amounts received in excess of conventional crude oil prices, continue to be treated as a reduction in crude oil costs to the refinery. This change by the APMC increases the Company's revenues and costs and operating expenses on an ongoing basis. In 1980 the increase was $26.5 million. Also, this change resulted in a reduction in inter-segment profit elimination, causing a one time increase in 1980 earnings of $1.0 million.

2. Royalties

(millions of dollars)	Crown	Other	Total 1980	Total 1979
Exploration, production and resources development	$ 40.8	$ 8.8	$ 49.6	$38.8
Oil sands	75.3	33.7	109.0	58.8
	$116.1	$42.5	$158.6	$97.6

3. Income taxes

The provision for income taxes in the Consolidated Statement of Earnings reflects a statement tax rate which is lower than the statutory tax rate. A reconciliation of the two rates is as follows:

	1980	1979
Federal tax rate	46.0%	46.0%
Federal surtax	1.8	—
Provincial abatement	(10.0)	(10.0)
Provincial tax rate	11.4	11.8
Statutory tax rate	49.2%	47.8%
Crown royalty disallowance	12.4	14.0
Resource allowance	(12.6)	(12.6)
Depletion allowance	(11.2)	(10.5)
Investment tax credits	(1.8)	(1.9)
Inventory allowance	(0.3)	(0.5)
Provincial royalty tax credits and rebates	(0.2)	(0.7)
Manufacturing and processing profits deduction and other	(0.7)	(2.0)
Statement tax rate	34.8%	33.6%

Investment tax credits reduced the income tax provision for 1980 by $8.6 million (1979—$4.9 million).

Deferred income taxes result from timing differences, the sources and the tax effects of which are as follows:

(millions of dollars)	1980	1979
Excess of tax over (under) book expense		
Depreciation	$47.3	$33.2
Exploration and development costs	20.8	14.1
Overburden removal	9.1	2.7
Preproduction expense	(1.0)	(0.7)
Other	1.0	(2.3)
	$77.2	$47.0

4. Extraordinary gains

The 1979 extraordinary gains of $3.1 million reflect reduced income taxes payable arising from recognition, for book purposes, of investment tax credits for years prior to 1979.

5. Related party transactions

In transactions with Sun Company, Inc. and its affiliates during 1980, the Company purchased crude oil and raw feedstocks for $77.2 million (1979—$8.5 million). In turn the Company sold refined products for $0.7 million (1979—$1.7 million).

These transactions were carried out on terms believed by the Company to be no less favourable than those that could have been obtained from unaffiliated persons.

Amounts due to Sun Company, Inc. and its affiliates at December 31, 1980 totalling $21.2 million (1979—$2.1 million) are included in accounts payable and accrued liabilities. Amounts due from Sun Company, Inc. and its affiliates totalling $0.2 million (1979—$0.1 million) are included in accounts receivable.

6. Supplemental earnings statement information

	(millions of dollars) 1980	1979
Synthetic crude oil receipts in excess of conventional crude oil prices	$314.5	$123.4
Export sales		
Unaffiliated customers—		
United States—heavy fuel oil	$ 96.8	$ 91.1
—petrochemicals	36.8	63.8
Europe —petrochemicals	83.8	64.0
	217.4	218.9
Affiliates—		
United States—refined products	0.7	1.7
	$218.1	$220.6
Research and development expenses	$ 6.3	$ 4.9
Interest expense—short-term	$ 0.6	$ 0.8
—long-term	5.9	6.7
	$ 6.5	$ 7.5

7. Inventories

	(millions of dollars) 1980	1979
Crude oil—conventional	$ 60.4	$ 22.0
—synthetic	22.8	18.3
Refined products	106.1	55.5
Materials and supplies	31.4	27.2
	$220.7	$123.0

8. Properties, plant and equipment

(millions of dollars)

	Properties, plant and equipment, at cost	Accumulated depreciation and depletion	Net 1980	Net 1979
Exploration, production and resources development				
Oil and gas properties	$ 415.6	$ 99.1	$316.5	$246.4
Equipment and other	93.6	28.8	64.8	54.7
	509.2	127.9	381.3	301.1
Oil sands				
Mining, plant and equipment	449.7	113.5	336.2	235.5
Housing	53.0	1.4	51.6	42.9
	502.7	114.9	387.8	278.4
Refining, petrochemicals and marketing				
Refinery including petrochemicals	139.8	50.5	89.3	85.7
Marketing and transportation	123.3	46.7	76.6	62.1
	263.1	97.2	165.9	147.8
Corporate	1.0	0.2	0.8	0.3
	$1,276.0	$340.2	$935.8	$727.6

9. Deferred charges

(millions of dollars)

	1980	1979
Oil sands deferred overburden removal costs (see below)	$ 69.3	$40.4
Oil sands preproduction costs	45.8	48.1
Prepaid gas purchases	12.0	4.1
Foreign exchange loss	1.9	1.9
Other	4.3	5.3
	$133.3	$99.8
Oil sands deferred overburden removal costs		
Balance, beginning of year	$ 40.4	$29.2
Outlays during year	49.4	28.5
Depreciation on equipment during year*	2.7	2.3
	92.5	60.0
Amortization during year	(23.2)	(19.6)
Balance, end of year	$ 69.3	$40.4

*Depreciation on overburden removal equipment is not included in depreciation, depletion and amortization expense of $84.1 million (1979—$67.3 million).

10. Long-term debt

	1980 (millions of dollars)	1979
5¾% Notes, maturing in 1991, repayable at the rate of U.S. $2.0 million annually. U.S. $30.0 million (1979—U.S. $32.0 million)	$35.8	$37.5
Bank term loan, basically at prime rate of interest plus one-half per cent, maturing in May 1983, prepayable at the Company's option, and prepaid on March 31, 1980	—	15.0
Mortgages on housing, bearing interest at rates between 6¼ and 11¾ per cent, repayable over the next 23 years	14.9	20.9
Capitalized lease obligations	0.1	0.1
	50.8	73.5
Less current portion of long-term debt	2.9	3.8
	$47.9	$69.7

Long-term debt matures as follows

1981	$ 2.9
1982	2.7
1983	2.7
1984	2.7
1985	2.7
Subsequent years	37.1
	$50.8

11. Share capital

Authorized:

—an unlimited number of preferred shares without nominal or par value, issuable in series, the first being Preferred Shares Series A originally 1 107 145 in number. Redemptions to December 31, 1980 have reduced the authorized number of Preferred Shares Series A to 1 078 827. Preferred Shares Series A have the following attributes:
$24 stated capital, $1.92 cumulative annual dividend, redeemable at $24, voting, convertible if and when a public distribution of common shares is made.

—an unlimited number of common shares without nominal or par value.

Issued:	Preferred Shares Series A Number	Amount (millions of dollars)	Common shares Number	Amount (millions of dollars)
Balance as at January 1, 1980	939 561	$22.6	52 245 085	$456.6
Redeemed for cash	580	0.1	—	—
Balance as at December 31, 1980	938 981	$22.5	52 245 085	$456.6

If and when a public distribution of common shares is made, the Preferred Shares Series A would be convertible into common shares during a 95 day period following such distribution, on the basis that $24 bears to the per share price (excluding commissions and discounts) at which the common shares are sold or issued for public distribution.

From August 22, 1979 to October 13, 1979 the Preferred Shares Series A were convertible to common shares on the basis of one common share for two Preferred Shares Series A.

The Preferred Shares Series A are redeemable at the option of the holder for $24 per share plus accrued and unpaid dividends at any time. The shares are redeemable also at the option of the Company at the same price following the 95 day conversion period.

Persons who held, or claim to have held, approximately 90 000 common shares of Great Canadian Oil Sands Limited at the time of amalgamation have demanded payment of the fair value of their shares in respect of which they claim to have dissented pursuant to the provisions of Section 184 of the Canada Business Corporations Act. Suncor Inc. has applied to the court for a determination of the persons entitled to be paid and the amount to be paid in accordance with the Act.

12. Reclassification

Certain 1979 amounts have been reclassified to conform with the 1980 presentation. Also see note 1(a) to the consolidated financial statements.

13. Commitments and contingencies

(a) The Company has undertaken an expansion of its oil sands plant at an estimated cost of $185 million to add about 2 000 cubic metres to daily production capacity. Construction commenced in 1979 and outlays to the end of 1980 were $128.1 million. The expansion is expected to be completed in 1981 with fully expanded production to be reached in 1982.

(b) The Company's Board of Directors has approved, subject to definitive engineering and feasibility studies, a proposal to upgrade the Sarnia refinery that would phase production of heavy fuel oil down to a level approximating inplant requirements at an estimated cost of $200 million. If, after the definitive studies, the costs of the upgrading proposal are acceptable, funds are to be committed before September 30, 1981, and substantial completion under normal circumstances is expected by December 31, 1984. If the proposal were not to proceed, the Government of Canada has indicated that changes in its established policy for the determination of export charges on heavy fuel oil produced by the Company could be implemented which would have an adverse effect on the Company.

(c) In March 1979 a suit was filed against the Company and the vendor of certain oil and gas properties which were purchased by the Company in 1973. The plaintiff has alleged that the vendor failed to honour a right of first refusal on the properties before completing certain transactions leading to the sale of the properties to the Company. The claim is for specific performance of the right of first refusal or, in the alternative, $35 million damages. If the plaintiff's suit is successful, indemnity will be claimed against the vendor.

(d) Minimum annual rental charges under leases for service stations, office space and other property and equipment approximate $4.5 million.

(e) The unfunded liability for past service costs, based on an independent actuarial valuation as of January 1, 1980, and including that arising from improvements made to the Company's pension plan during 1980, is estimated at $11.2 million as at December 31, 1980.

While the result of any litigation necessarily contains an element of uncertainty, the Company's management presently believes that, with respect to the above and other known contingent liabilities, including lawsuits, claims and guarantees, the aggregate amount of any liability and costs which might result would not have a materially adverse effect on the Company's consolidated financial position or operating results.

14. National Energy Program

(a) Prices for synthetic crude oil production

Commencing April 4, 1979 the Company received the world price for its entire synthetic crude oil production as part of an arrangement with the Government of Canada under which the Company undertook to expand its oil sands plant. On October 28, 1980 the National Energy Program ("NEP") of the Government of Canada stated that production from the Company's existing oil sands plant would receive the conventional crude oil price, and expanded production would be entitled to the oil sands reference price. Accordingly, from November 7, 1980, the Company has received the conventional crude oil price for revenues from its entire synthetic crude oil production. Under the NEP the oil sands reference price was $38.00 per barrel as of January 1, 1981 at which time the conventional crude oil price was $17.75 per barrel.

If the Company had received only the conventional crude oil price since January 1, 1980 its earnings for the year ended December 31, 1980 (adjusted for related changes in royalties and income taxes), would have been $136.4 million compared with actual earnings of $306.4 million.

The Company has requested the Government of Canada to reconsider pricing of its synthetic crude oil production. The outcome of these representations is not known at the present time.

(b) Petroleum and gas revenue tax

The NEP proposed an 8% tax as of January 1, 1981 on net operating revenues from the production of crude oil (including synthetic crude oil) and natural gas. The tax is not deductible for federal or provincial income tax purposes.

If the 8% petroleum and gas revenue tax had been in effect since January 1, 1980, and if the Company had received only the conventional crude oil price as described in (a) above, its earnings for the year ended December 31, 1980 (adjusted for related changes in royalties and income taxes), would have been approximately $119 million compared with actual earnings of $306.4 million.

The NEP contains several other proposals including those for pricing of conventional crude oil and natural gas; new taxes on natural gas sales; increasing the Canadian ownership of the oil and gas industry; the establishment without compensation of a 25% interest in federal frontier lands for the Government of Canada; the phasing down of earned depletion allowances; and the establishment of a new petroleum incentives program.

Legislation to implement the NEP has not yet been enacted by the Parliament of Canada and the proposals may be revised in the legislative process. In addition, the governments of certain provinces have disagreed with some of the proposals in the NEP.

Suncor inc.

Quarterly Summary (unaudited)

Financial data

(dollars in millions, except per share amounts)

	For the quarter ended				Total year	For the quarter ended				Total year
	Mar 31	June 30	Sept 30	Dec 31	1980	Mar 31	June 30	Sept 30	Dec 31	1979
Revenues	$291.3	$325.0	$333.9	$309.2	$1,259.4	$173.9	$187.6	$218.3	$285.3	$865.1
Segment operating profits										
Exploration, production and resources development	11.7	5.4	8.5	9.3	34.9	8.7	8.8	6.1	11.5	35.1
Oil sands	80.4	92.6	91.2	32.2	296.4	11.9	14.6	38.2	73.8	138.5
Refining, petrochemicals and marketing	33.6	27.6	29.1	25.2	115.5	10.2	13.9	25.2	34.7	84.0
	$125.7	$125.6	$128.8	$66.7	$446.8	$ 30.8	$ 37.3	$ 69.5	$120.0	$257.6
Earnings before extraordinary gains	87.3	87.4	80.7	51.0	306.4	18.8	22.3	50.2	78.5	169.8
Extraordinary gains	—	—	—	—	—	—	—	3.1	—	3.1
Earnings for the period	$ 87.3	$ 87.4	$ 80.7	$ 51.0	$306.4	$ 18.8	$ 22.3	$ 53.3	$ 78.5	$172.9
Funds from operations	$120.5	$102.4	$ 95.8	$ 99.3	$418.0	$ 39.5	$ 44.8	$ 75.5	$ 92.6	$252.4
Earnings before extraordinary gains per common share	$ 1.66	$ 1.67	$ 1.53	$ 0.97	$ 5.83	$ 0.35	$ 0.43	$ 0.96	$ 1.50	$ 3.24

Operating data

	For the quarter ended				Total year	For the quarter ended				Total year
	Mar 31	June 30	Sept 30	Dec 31	1980	Mar 31	June 30	Sept 30	Dec 31	1979
Gross production										
Conventional crude oil and natural gas liquids (a)	2.7	2.6	2.7	2.3	2.6	2.6	2.6	2.6	2.9	2.7
Synthetic crude oil (a)	7.2	8.4	7.6	6.4	7.4	7.4	5.0	5.7	8.9	6.8
Gross natural gas sales (b)	2.4	1.3	1.6	1.5	1.7	2.5	1.9	1.0	1.6	1.8
Sales of refined products (a)	11.9	10.8	11.9	12.0	11.6	12.5	11.2	11.1	12.3	11.8

(a) thousands of cubic metres per day
(b) millions of cubic metres per day

Financial Five Year Summary (unaudited)

(dollars in millions except for ratios)	1980	1979	1978	1977	1976
Revenues	$ 1,259.4	$ 865.1	$ 562.5	$ 475.8	$ 405.5
Segment revenues					
Exploration, production and resources development	152.5	125.3	106.9	92.3	62.8
Oil sands	595.3	343.4	210.1	178.7	158.3
Refining, petrochemicals and marketing	831.4	684.4	517.5	438.5	383.5
	$ 1,579.2	$ 1,153.1	$ 834.5	$ 709.5	$ 604.6
Segment operating profits					
Exploration, production and resources development	34.9	35.1	36.8	31.5	18.4
Oil sands	296.4	138.5	37.9	26.8	24.0
Refining, petrochemicals and marketing	115.5	84.0	19.2	23.6	13.3
	$ 446.8	$ 257.6	$ 93.9	$ 81.9	$ 55.7
Earnings before extraordinary gains	306.4	169.8	57.8	36.0	23.1
Extraordinary gains	—	3.1	3.1	6.3	2.9
Earnings for the year	$ 306.4	$ 172.9	$ 60.9	$ 42.3	$ 26.0
Funds from operations	$ 418.0	$ 252.4	$ 126.0	$ 94.9	$ 72.6
Purchases of properties, plant and equipment					
Exploration, production and resources development	110.0	64.4	61.3	34.9	19.5
Oil sands	132.2	59.4	18.5	25.4	15.1
Refining, petrochemicals and marketing	29.0	8.9	20.1	11.4	20.3
Corporate	0.7	0.1	—	—	—
	$ 271.9	$ 132.8	$ 99.9	$ 71.7	$ 54.9
Capital employed					
Long-term debt	47.9	69.7	77.6	91.2	88.8
Deferred revenues, deferred taxes and minority interest	278.9	191.2	138.8	107.8	83.6
Shareholders' equity	1,102.3	797.6	627.5	566.6	524.3
	$ 1,429.1	$ 1,058.5	$ 843.9	$ 765.6	$ 696.7
Number of common shares	52 245 085	52 191 626	52 175 200	52 175 200	52 175 200
Ratios					
Earnings before extraordinary gains per common share	$5.83	$3.24	$1.11	$0.69	$0.44
Earnings per common share	$5.83	$3.30	$1.17	$0.81	$0.50
Funds from operations per common share	$8.00	$4.84	$2.41	$1.82	$1.39
Earnings as a percentage of shareholders' equity	32.3%	24.3%	10.2%	7.8%	5.1%
Earnings as a percentage of capital employed	24.6%	18.2%	7.6%	5.8%	3.9%
Earnings as a percentage of revenues	24.3%	20.0%	10.8%	8.9%	6.4%
Long-term debt as a percentage of capital employed	3.4%	6.6%	9.2%	11.9%	12.7%

Operating Five Year Summary (unaudited)

Resources Group

	1980	1979	1978	1977	1976
Production (a)					
Conventional crude oil and natural gas liquids					
—gross	2.6	2.7	2.5	2.5	2.5
—net	1.7	1.8	1.6	1.5	1.6
Synthetic crude oil—gross	7.4	6.8	7.1	7.1	7.6
Natural gas sales (millions of cubic metres per day)					
Gross	1.7	1.8	1.8	1.9	1.4
Net	1.1	1.2	1.2	1.2	1.0
Average sales price					
Conventional crude oil (dollars per cubic metre)	96	81	76	63	46
Synthetic crude oil (dollars per cubic metre)	217	137	81	69	57
Natural gas (dollars per thousand cubic metres)	82	56	47	40	31
Gross proven reserves (b)					
Conventional crude oil and natural gas liquids (c)	10	12	12	15	16
Synthetic crude oil (c)	56	65	67	69	72
Natural gas (billions of cubic metres)	13	14	13	16	15
Land holdings (millions of hectares)					
Gross	19.6	19.7	23.9	26.5	26.7
Net	3.3	5.1	6.2	6.6	6.9
Net wells completed					
Exploratory —oil	2	—	1	—	—
—gas	9	4	5	5	1
—dry	14	12	6	9	2
Development—oil	12	39	27	11	1
—gas	25	23	40	36	8
—dry	7	7	7	1	1
	69	85	86	62	13

Sunoco Group

	1980	1979	1978	1977	1976
Crude oil supply and refining					
Refined for Suncor account (a)	11.8	11.8	10.6	11.9	10.3
Gross crude oil production as a percentage of crude oil refined for Suncor account	84%	79%	89%	80%	97%
Processed at Suncor refinery (a)	12.4	12.2	11.1	12.2	12.3
Utilization of refining capacity	86%	85%	77%	85%	91%
Sales of refined products (a)					
Gasolines	4.6	4.3	4.0	4.0	3.7
Middle distillates	2.8	2.9	2.6	2.5	2.6
Heavy fuel oil	2.6	3.0	3.4	3.4	3.5
Petrochemicals	1.1	1.1	0.8	0.6	0.2
Lubes, greases, specialty oils and other	0.5	0.5	0.6	0.5	0.5
	11.6	11.8	11.4	11.0	10.5
Service stations (number at year-end)	920	950	990	1 040	1 140

	1980	1979	1978	1977	1976
Suncor employees (number at year-end)	4 620	4 310	4 130	4 000	3 900

(a) Thousands of cubic metres per day.
(b) Reserve estimates for 1980, 1979 and 1978 were prepared by independent consultants. Estimates for 1977 and 1976 were prepared by the Company.
(c) Millions of cubic metres.

Board of Directors

Suncor has eleven directors, eight of them Canadians and five of these independent, outside directors having no other association with the Company or its parent.

The Board operates by a detailed, written job description. Besides outlining the Board's goals and duties, this job description provides for independence of action well beyond the norm for subsidiary companies.

There are three standing committees of the Board: Audit; Board Policy and Nominating; and Human Resources and Compensation. Each committee is chaired by an outside director. The Audit Committee has a majority of outside directors.

Two new directors were appointed in 1980—Gerald Hobbs and Guy Saint-Pierre. Their biographies follow. Newton Hughes, Chairman of our Audit Committee, resigned. Mr. Hughes' counsel was considered most valuable in formulating the direction of our new Company. We acknowledge his contribution with deep gratitude.

Gerald H.D. Hobbs
New Director

Gerald Hobbs is a director of such companies as the Bank of Nova Scotia, MacMillan Bloedel Limited, Okanagan Helicopters, British Columbia Telephone Company and a governor of the University of British Columbia. He was formerly Chairman of Cominco Ltd. He is a member of Suncor's Board Policy and Nominating Committee where he contributes broad experience in the management of large companies.

Guy Saint-Pierre
New Director

Guy Saint-Pierre is President and Chief Executive Officer of Ogilvie Mills Ltd. and Senior Vice-President of John Labatt Limited. Formerly Minister of Education and later Minister of Industry and Commerce in the Quebec government, Mr. Saint-Pierre is currently a director of a number of other major companies and the Clinical Research Institute of Montreal. He is a member of the Suncor Board's Human Resources and Compensation Committee.

Gerald H.D. Hobbs

Guy Saint-Pierre

Glossary of Terms

Bitumen: extremely tarry form of oil that coats individual particles of sand in ore body; extracted from ore and upgraded (freed of impurities) to the form of synthetic crude oil.
Bucketwheel: a major piece of equipment used to scoop oil-bearing sands from the mine face.
Coke: by-product of heating bitumen to 500 degrees Celsius; a fuel used in the power plant.
Conventional crude oil: oil and natural gas liquids, including condensate, produced at the wellhead or extracted on surface by ordinary production methods.
Distillate hydrocracking: an efficient, relatively low-temperature refining process using hydrogen and a catalyst to convert middle-boiling material to high-octane gasoline, reformer charge stock, jet fuel and/or high-grade fuel oil.
Downstream: manufactures, distributes and markets refined products from crude oil.
Drillship: a ship which has a hull fitted with a drilling rig capable of drilling in deep water. May be self-propelled. Some carry all supplies and equipment needed to drill and complete a well.
Drillstem test: a test performed during the drilling of a well to determine if hydrocarbon-bearing zones have been encountered.
Dry hole: an exploration or development well incapable of producing hydrocarbons economically.
Electrostatic precipitators (ESPs): electrically-charged screens that attract and remove particulates from emissions.
Farmout: an agreement whereby the owner of a lease permits another operator to earn an interest in the lease by carrying out certain work. From the other operator's point of view, this same agreement is a farmin.
Gross production/reserves: Suncor's interest before deducting Crown royalties, freehold and overriding royalty interests and provincial mineral taxes on production.
Gross wells/land holdings: the total in which Suncor has an interest.
Heavy oil: crude oil which is more viscous, or thicker, than normal crudes and therefore does not flow as freely.
Hydrocarbons: organic chemical compounds of hydrogen and carbon atoms which form the basis of all petroleum products. May exist as gases, liquids or solids.
In situ oil sands production: separation of oil from the sand within the ore body itself and inducing the oil to flow so that it can be pumped to the surface.
Natural gas liquids: hydrocarbons found in natural gas which may be extracted or isolated as a liquid at standard temperatures and pressures.
Net production/reserves: Suncor's working interest after deducting Crown royalties and freehold and overriding royalty interests.
Net wells/land holdings: Suncor's interest after deducting interests of partners.
Overburden: material overlying oil sand which must be removed before sand can be mined; consists of muskeg (organic soil), glacial deposits and sand.
Proven reserves: hydrocarbons which have been discovered and determined to be economically recoverable but are still in the ground.
Reservoir: a body of porous rock containing an accumulation of water, crude oil or natural gas.
Restricted choke flow: a wellhead device which is used to control flow from the well.
Royalty: a percentage of production which an oil company pays to the owner of the mineral rights. Owner may be provincial or federal governments or a freehold or lease owner.
Seismic: a geophysical technique which helps to determine the oil and gas potential of an area.
Spud: to start drilling a well.
Synthetic crude: the blend of desulphurized naphtha, kerosene and gas oil that is made from the hydrocarbons resulting from the thermal cracking of bitumen.
Tailings: mixture of sand, water and clay remaining after bitumen has been removed from the ore; stored in a diked-in pond.
Thermal cracking: refining process which uses heat and pressure to break the large hydrocarbon molecules found in bitumen into smaller hydrocarbon molecules and coke.
Throughput: the quantity of material processed within a given period of time.
Turnaround: a maintenance project conducted in refineries and oil sands plants during which production equipment is shut down, repaired or overhauled and returned to operation.
Upstream: explores for, develops and produces crude oil and natural gas; develops and produces synthetic crude and heavy oil from the oil sands; pursues coal, uranium and mineral activities.
Wells:
- **completed:** a well having a definite status—gas, oil or dry.
- **delineation:** a well drilled in close proximity to an oil or gas well to help determine the limits of the reservoir.
- **development:** a well drilled with the expectation of producing from known-productive oil or gas reservoir.
- **exploratory:** a well drilled in unproven or semi-proven territory to find commercial deposits of crude oil or natural gas in a new reservoir.

Metric conversion guide

Crude oil, refined products, etc.	1 m^3 (cubic metre) = approx. 6.29 barrels
Natural gas	1 m^3 (cubic metre) = approx. 35.49 cubic feet
Land holdings	1 hectare = approx. 2.47 acres

Corporate Office

Suncor's corporate office spearheads and coordinates a number of key areas: corporate, long-range strategic planning and socioeconomic issues analysis; financial and accounting controls, insurance, taxation and treasury administration; investor relations and external financial reporting; technology, research and development and environmental affairs; legal affairs, human resources, government relations, internal communication and public affairs. Responsibility for many of these functions is shared with the operating groups.

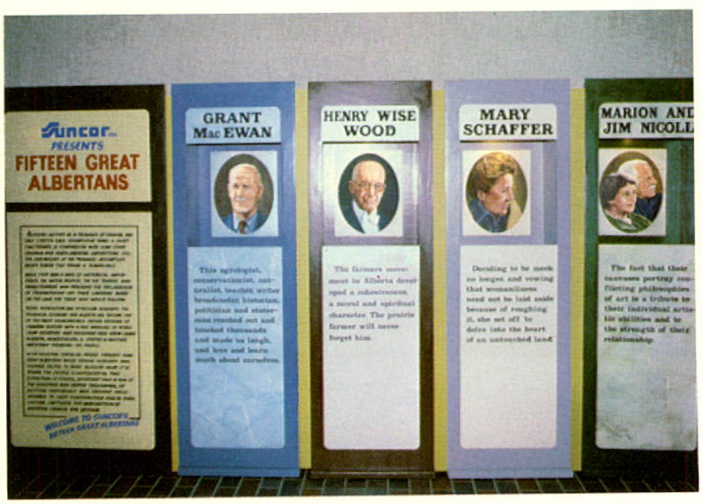
During 1980, the most important task was to put in place the staff and systems necessary to direct and control the much larger and more complex company resulting from the amalgamation which formed Suncor in 1979. Actions taken included complete rewriting of corporate policy governing standards of business conduct, human resources and the environment; an upgrading and expansion of the Controller's Department; and appointment of a Director of Legal Affairs. Previously, all corporate and Sunoco Group legal work had been handled by outside counsel. New, Company-wide administrative systems such as employee performance planning and review were implemented. We also tested "vertical sensing" in 1980—a communication process designed to improve upward flow of information and encourage employees at all levels to speak up. The initial tests were successfully conducted in the Sunoco Group and more are planned in 1981.

To commemorate Alberta's 75th anniversary as a province, Suncor presented an exhibition of "Great Albertans" honouring some of the people who contributed to its development. For the exhibit, Suncor commissioned from Calgary artist Don Inman 15 portraits set in six-foot lighted panels. The exhibition toured 10 communities before being donated to the Alberta Art Foundation.

As a new public Company, financial reporting and investor relations were also highlighted. Suncor's first annual report won first prize among oil companies and second prize overall in the prestigious *Financial Post* contest as well as second prize in *Oilweek's* annual competition. One major reason for these successes was the degree of disclosure—a priority established prior to amalgamation.

Another major task was to prepare Suncor for a large distribution of common shares to the Canadian public. A prospectus was prepared and underwriters were selected. However, the public issue was held back pending a new pricing formula for synthetic crude oil which became necessary when, on March 28, 1980, the federal government announced its intention to reconsider its world price agreement with Suncor. A new pricing policy was released as part of the new National Energy Program on October 28, but as discussed in the President's Report, the price unilaterally imposed upon Suncor was far too low, thus further delaying our plans to increase Canadian ownership of Suncor. Subsequent negotiations concerning the National Energy Program became a top priority for our Company.

Part of the display of original art commissioned by Suncor to commemorate great Albertans during the province's 75th anniversary.



Corporate Directory

Offices

Corporate Office
20 Eglinton Avenue West
Toronto, Ontario M4R 1K8
Telephone (416) 485-2500

Sunoco Group
56 Wellesley Street West
Toronto, Ontario M5S 2S4
Telephone (416) 924-4111

Resources Group
Exploration, Production
& Resources Development Divisions
500–4th Avenue S.W.
P.O. Box 38
Calgary, Alberta T2P 2V5
Telephone (403) 269-8100

Resources Group
Oil Sands Division
10123–99th Street
Edmonton, Alberta T5J 3H9
Telephone (403) 421-2115

Subsidiary Companies

Albersun Pipeline Ltd.
Calgary, Alberta
Natural gas pipeline operator

Athabasca Realty Company Limited
Fort McMurray and Edmonton, Alberta
Employee housing

Baron Petroleums Inc.
Toronto, Ontario
Retail gasoline distributor

Gow Fuels Inc.
Hull, Quebec
Heating oil and gasoline distributor

Maywelle Properties Ltd.
Toronto, Ontario
Real estate developer

Ouimet-Gobeille Inc.
Montreal, Quebec
Heating oil and gasoline distributor

SMS Petroleums Ltd.
Toronto, Ontario
Retail gasoline distributor

Sun-Canadian Pipe Line Company Limited
Waterdown, Ontario
Petroleum products pipeline operator in southern Ontario (55% owned)

Suncor Supply Limited
Fort McMurray and Edmonton, Alberta
Provision of materials and supplies

Sun Explorations of Quebec Ltd.
Calgary, Alberta
Exploration in Quebec

Sunoco Home Comfort Inc.
Toronto, Ontario
Heating oil and gasoline distributor with various divisions in Ontario

Sunoco Inc.
(including Sunchem division)
Toronto, Ontario
Manufacturer/marketer of petroleum and petrochemical products

Chemsun Inc.
Toronto, Ontario
Marketer of petrochemical products

Sunchem Shipping Inc.
Toronto, Ontario
Marine transportation

Directors

Max B. E. Clarkson, Toronto
Professor
Faculty of Management Studies
University of Toronto

Ross A. Hennigar, Toronto

Gordon E. Hillhouse, Radnor, Pa.
Executive Vice-President
Sun Company, Inc.

Gerald H.D. Hobbs, Vancouver
Private Investor & Corporate Director

Ardagh S. Kingsmill, Q.C., Toronto
Partner, Tilley, Carson & Findlay

Michael M. Koerner, Toronto
President, Canada Overseas Investments Limited

Robert McClements, Jr., Radnor, Pa.
Executive Vice-President
Sun Company, Inc.

Dudley M. McGeer, Toronto

John P. Neafsey, Radnor, Pa.
Senior Vice-President, Finance
Sun Company, Inc.

John E. Poole, Edmonton
Corporate Director

J. A. Guy Saint-Pierre, Montreal
President & Chief Executive Officer
Ogilvie Mills Ltd.

Principal Officers

R. A. Hennigar, President and Chief Executive Officer

S. A. Cowtan, Executive Vice-President, Sunoco Group

W. R. Loar, Executive Vice-President, Resources Group

D. M. McGeer, Senior Vice-President, Administration and Chief Financial Officer

F. A. Bain, Vice-President, Technology

C. K. Boland, Vice-President, Human Resources and Corporate Affairs

P. M. Bradbury, Vice-President, Controller, Resources Group

G. H. Brereton, Vice-President, Refining, Sunoco Group

J. S. Camp, Vice-President, Oil Sands Division, Resources Group

H. B. Maxwell, Vice-President, Government Affairs

W. L. Oliver, Vice-President, Administration, Resources Group

D. A. Smith, Vice-President, Exploration Division, Resources Group

W. N. Turner, Vice-President, Production Division, Resources Group

A. S. Kingsmill, Q.C., Secretary

A. A. L. Wright, Treasurer and Assistant Secretary

Majority Shareholder

Sun Company, Inc.
Radnor, Pennsylvania
(owning 99.87% of common shares)

Stock Exchange Listings

The Suncor Preferred Shares Series A are listed on the Toronto and Alberta Stock Exchanges.

Transfer Agent and Registrar

The Canada Trust Company
110 Yonge St., Toronto,
Ontario M5C 1T4
800 Dorchester Blvd. W., Montreal,
Quebec H3B 3L3
10150–100th St., Edmonton,
Alberta T5J 0P6
505–3rd Ave. S.W., Calgary,
Alberta T2P 3E6

Investor Information

Information to assist the investor in evaluating the Company's operations and results, including additional copies of this annual report or the annual report on Form 10-K filed with the Securities and Exchange Commission may be obtained from the Manager, Investor Relations, Suncor Inc. at 20 Eglinton Avenue West, Toronto, Ontario M4R 1K8.

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