Suncor inc.

ANNUAL INFORMATION FORM

SUNCOR INC.
36 York Mills Road
North York, Ontario
M2P 2C5

March 19, 1992

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TABLE OF CONTENTS

GLOSSARY OF TERMS

Barrel of Oil Equivalent (or "BOE"): converts natural gas to crude oil on the approximate long-term economic equivalent basis of 10,000 cubic feet of natural gas equals one barrel of oil or 1,773 cubic metres of natural gas equals one cubic metre of oil.

Bitumen/Heavy Oil: extremely viscous (tar-like) form of oil which cannot be produced by conventional means. When extracted from oil sands and upgraded, it becomes synthetic crude oil.

Condensates: a mixture mainly of pentanes and heavier hydrocarbons.

Conventional Crude Oil: oil produced through wells by normal oil field methods.

Conventional Heavy Oil: crude oil which is more viscous or thicker than average crudes, and therefore does not flow as freely, but which can be produced by conventional means.

Cash Operating Costs: for Oil Sands Group cash operating costs include operating and maintenance costs, overburden cash expenditures and the amortization of maintenance shutdown expenditures, but exclude royalties, capital expenditures, other amortization, head office overhead, interest and net employee housing.

Costs:

development: include all costs associated with moving reserves from other classes to the proved producing class.

finding: include the cost of and investment in undeveloped land, geological and geophysical activities, exploratory drilling and direct administrative costs necessary to discover oil and gas proved and probable reserves.

lifting: include all expenses related to the operation and maintenance of producing or producible wells, gas plants and gathering systems.

Downstream: this business segment manufactures, distributes and markets products refined from crude oil.

Dry Hole/Well: an exploration or development well incapable of producing commercial quantities of hydrocarbons, which is plugged and abandoned.

Gross Production/Reserves: Suncor's interest before deducting Crown royalties and freehold and overriding royalty interests.

Gross Wells/Land Holdings: the total in which Suncor has an interest.

Heavy Fuel Oil: the residue from refining of conventional crude oil which remains after the lighter products such as gasolines, aromatics, naphtha and kerosene have been extracted from the crude oil.

Horizontal Drilling: drilling horizontally rather than vertically through a reservoir, thereby exposing more of the well to the reservoir rock and typically increasing production.

In Situ Heavy Oil: crude oil which is more viscous or thicker than normal crudes, and therefore does not flow as freely, which is separated by the injection of steam or other means from the sands in the reservoir.

Natural Gas Liquids: propane, butanes or pentanes plus, or a combination of them, obtained from the processing of raw gas or condensates.

Net Production/Reserves: Suncor's interest after deducting Crown royalties and freehold and overriding royalty interests.

Net Wells/Land Holdings: Suncor's interest after deducting the interests of partners.

Non-conventional Oil: oil which is not produced through wells by normal oil field methods, such as synthetic crude or in situ heavy oil.

Oil Sands: consists of a mixture of sand and bitumen.

Overburden: material overlying oil sands that must be removed before oil sands can be mined, consisting of muskeg (organic soil), glacial deposits and sand.

Reservoir: a body of porous, permeable rock containing an accumulation of crude oil, natural gas, natural gas liquids or water.

Synthetic Crude: a blend of hydrocarbons resulting from the thermal cracking and upgrading of bitumen by coking and distillation, resulting in a light, low sulphur synthetic crude.

Undeveloped Oil and Gas Lands: lands on which no producing or commercially producible well has been drilled.

Upstream: these business segments explore for, acquire, develop, produce and market crude oil and natural gas and develop and produce synthetic crude and heavy oil from the oil sands.

Wells:

development: a well expected to produce from a known productive oil or gas reservoir.

drilled: a well having a definite status — gas well, oil well or dry and abandoned.

exploratory: a well in unproved or semi-proved territory drilled to find commercial deposits of crude oil or natural gas in a new reservoir.

infill: a well in an existing developed field that allows for the acceleration or additional recovery of reservoir fluids.

Workover: to perform subsurface work on a well for the purposes of improving, reestablishing or maintaining production.

CONVERSION TABLE (1)

1 barrel	= 0.159 cubic metres	1 cubic metre (m^3)	= 6.29 barrels
1 cubic foot (natural gas)	= 0.0283 cubic metres	1 cubic metre (natural gas)	= 35.49 cubic feet
1 cubic yard (overburden)	= 0.7646 cubic metres	1 cubic metre (overburden)	= 1.31 cubic yards
1 imperial gallon	= 4.55 litres	1 litre	= 0.22 imperial gallons
1 acre	= 0.405 hectares	1 hectare	= 2.47 acres
1 ton (long)	= 1.016 tonnes	1 tonne	= 0.984 tons (long)
1 ton (short)	= 0.907 tonnes	1 tonne	= 1.102 tons (short)
1 mile	= 1.609 kilometres	1 kilometre	= 0.62 miles
1 foot	= 0.304 metres	1 metre	= 3.28 feet

(1) Conversion using the above factors on rounded numbers appearing in this Annual Information Form may produce small differences from reported amounts.

Some information in this Annual Information Form is set forth in metric units and some in imperial units.

ITEM 1 INCORPORATION

(1) Incorporation of Issuer

Suncor Inc. was originally formed by the amalgamation under the Canada Business Corporations Act on August 22, 1979 of Sun Oil Company Limited, incorporated in 1923, and Great Canadian Oil Sands Limited, incorporated in 1953. On January 1, 1989, Suncor amalgamated with a wholly owned subsidiary under the Canada Business Corporations Act. Its registered and principal office is located at 36 York Mills Road, North York, Ontario, M2P 2C5. In this annual information form, references to Suncor include Suncor Inc. and its subsidiaries unless the context otherwise requires.

(2) Subsidiaries of Suncor

Suncor's only principal subsidiary is Sunoco Inc. This subsidiary which is wholly owned by Suncor is incorporated under the laws of Ontario and carries on the businesses of refining and marketing of petroleum products and petrochemicals directly and indirectly through subsidiaries.

ITEM 2 GENERAL DEVELOPMENT OF THE BUSINESS

Suncor, a Canadian integrated oil and gas company, is engaged in the exploration for and production and marketing of crude oil and natural gas and in the refining of crude oil and the marketing of petroleum and petrochemical products. Suncor has three principal operating groups: Oil Sands Group, based near Fort McMurray, Alberta, which produces synthetic crude oil from Athabasca oil sands; Resources Group, based in Calgary, Alberta, which explores for and produces natural gas and conventional and non-conventional crude oil and markets natural gas; and Sunoco Group, with headquarters in Toronto, Ontario, which markets and refines crude oil and markets a broad range of petroleum and petrochemical products.

In 1991, Suncor produced approximately 70,000 barrels (11,100 m^3) per day of synthetic and conventional crude oil (approximately 5% of Canada's oil production) and 105 million cubic feet (3.0 million m^3) per day of natural gas. In 1990, Suncor was the eighth largest crude oil producer and the twenty-fifth largest natural gas producer in Canada. In 1991, Suncor sold approximately 81,000 barrels (12,900 m^3) per day of refined products, mainly in its core regional markets in Ontario and Quebec. Suncor has a market share of approximately 10% of the Ontario retail gasoline market and approximately 5% of the Quebec retail gasoline market.

Suncor's objective is to continue to improve the competitive position of each of its operating groups and to achieve a better balance in earnings and cash flow from each operating group, principally by increasing its investment in its conventional crude oil and natural gas exploration and production business.

Suncor believes that it has strategic advantages resulting from the synergies in its operations and that these synergies will enhance its ability to compete in the difficult market conditions currently prevailing. The upstream industry environment in which Suncor operates has been characterized by volatile crude oil prices, reduced demand for heavy oil, fluctuating price differentials between heavy and light grades of crude oil and oversupply of natural gas causing depressed prices. The downstream business has experienced overcapacity, volatile but primarily low margins and declining demand for fuel oil and heavy petroleum products. Some of these conditions have been exacerbated by the Iraq/Kuwait war and the current recession. This environment is reducing the industry's cash flow and earnings. Despite these difficult market conditions, Suncor reported net earnings of $77 million and cash provided from operations, before changes in operating working capital, of $303 million in 1991.

Recent public announcements by some downstream competitors indicate that they have plans to address the overcapacity in the Canadian downstream business by closing a number of refineries, bulk plants and service stations over the next few years.

Suncor's upstream oil production is primarily light, low sulphur crude oil as a result of the characteristics of the synthetic crude oil produced at its oil sands plant and the quality of the conventional crude oil produced by Resources Group which is lighter than the Canadian average. Suncor's upstream production nearly balances its refinery crude feedstock requirements. Suncor believes this balance reduces the volatility of its earnings and cash flow due to world supply disruptions and other factors that cause crude oil and product price changes. In addition, Suncor uses its natural gas both at its Sarnia refinery and at its oil sands plant as feedstock and fuel. When gas prices are depressed, the lower cost of internal consumption partially offsets the loss of revenue in Resources Group, which lessens the impact on Suncor's earnings.

The configuration of Suncor's refinery in Sarnia, Ontario permits the processing of a substantial amount of synthetic crude oil. Synthetic crude oil is low in sulphur and heavy ends, yielding a substantially lighter product slate. This results in Suncor having a more highly valued product mix when compared to yields from average Canadian conventional crude oil and when compared to most other Canadian refineries. See also Item 3 — "Narrative description of the business".

ITEM 3 NARRATIVE DESCRIPTION OF THE BUSINESS

OIL SANDS GROUP

Suncor produces synthetic crude oil by mining the Athabasca oil sands and upgrading the bitumen extracted at its plant site located near Fort McMurray, Alberta. Suncor pioneered commercial production of synthetic crude oil from oil sands, with initial plant production beginning in 1967. The oil sands operation represents a significant portion of Suncor's asset base, cash flow and earnings. Suncor made substantial investments over the last five years to improve the reliability and flexibility of the oil sands operation, which contributed to a record production level of approximately 60,600 barrels (9,600 m^3) per day in 1991. Oil Sands Group has secure reserves for the next twelve years. Management is evaluating a number of options to secure the long range future of the operation. See "Outlook".

The following table sets forth the earnings, cash provided from operating activities and capital expenditures of Oil Sands Group for the years indicated.

	Year ended December 31				
	1991	1990	1989	1988	1987
			($ millions)		
Earnings (loss)	48	78	41	(10)	30
Cash provided from (used in) operating activities	174	128	117	(7)	125
Capital expenditures	76	31	41	68	35

The objectives of Oil Sands Group are to continue to increase production, improve day-to-day reliability and lower costs.

Operations

Oil sands consist of a mixture of sand and bitumen. Suncor's integrated oil sands business involves a mining and extraction operation and a heavy oil upgrading process. The first phase, an open pit mining operation, removes overburden with mobile trucks and shovels. Large bucketwheel excavators mine oil sands which are loaded onto conveyor systems covering approximately 10 miles (16 kilometres) which move the oil sands to Suncor's extraction plant. Bitumen is extracted from the sands by a hot water process which uses a settling separation method followed by dilution with naphtha (diluent) and the removal of water and fine sand in centrifuges.

The second phase of the operation involves heavy oil upgrading. The bitumen from the extraction plant is first separated from the diluent and then is upgraded by coking, distillation and hydrogen treatment to remove sulphur and nitrogen. The upgraded distillates are blended into synthetic crude oil according to customer specifications. Most of the synthetic crude is then shipped in Suncor's 266 mile (426 kilometre) pipeline to Edmonton, Alberta for sale and distribution to Suncor's Sarnia refinery and others.

To produce steam and electric power, Suncor operates its own utility plant using coke extracted from the bitumen as fuel. Additional power is purchased from an Alberta public utility. The operation also consumes natural gas which is carried to the plant through a pipeline owned by Suncor which runs from north of Edmonton. The natural gas includes volumes produced by Suncor, as well as gas purchased from others under long-term supply contracts. Under current provincial regulations, the gas produced by Suncor and used in the oil sands plant is generally royalty free.

The oil sands plant is susceptible to loss of production due to the interdependence of the component systems. Under Suncor's business interruption insurance coverage, Suncor would bear at least the first $50 million of any loss arising from a future insured incident at its oil sands operation. Severe climatic conditions such as extreme cold can also cause reduced production. Over the past several years, back-up and spare components and systems have been introduced in critical areas to reduce vulnerability caused by component interdependence. Major efforts and investment have been made over the same period to increase production, improve reliability and reduce cash operating costs. These efforts have also reduced susceptibility to climatic extremes. Since 1983 such investments have totalled in excess of $400 million. In addition, approximately $10 million was spent in 1988 on a diluent recovery unit which, together with other operating improvements, has resulted in an 8% increase in the average synthetic crude oil yield from bitumen.

Oil Sands Group also has improved process and systems controls in most areas of the plant, improved preventive and predictive maintenance programs, increased capacity in a number of areas of the plant, developed improved processes for coordinating and scheduling of maintenance and operations, improved union and management relations and implemented better loss control and safety programs. Full plant maintenance shutdowns are now planned for every three rather than two years and smaller, less disruptive shutdowns of systems are planned in intervening years. Increased plant reliability also has resulted in a 33% reduction in natural gas consumption since 1986 despite production increases.

Improvements to preventative and predictive maintenance programs include vibration analysis on equipment to detect deterioration before failure, lube oil analysis on key pieces of equipment to provide early warning of problems, corrosion surveys to detect pipe thinning before failure and use of equipment database analysis to predict problems. The 1990 maintenance shut down described below was evaluated by outside consultants retained by Oil Sands Group. The evaluation addressed causes other than the preventative and predictive maintenance programs and did not attribute the shut down problems to deficiencies in such programs.

Improvements in the co-ordinating and scheduling of maintenance and operations include an operations-wide Production, Planning and Control Group which provides integrated coordination of maintenance planning with production; a Production Committee, directed by the Production, Planning and Control Group, which focuses on reducing total restrictions on output; and the upgrading of maintenance planning and work scheduling information systems.

Plant capacity has been increased as a result of improvements and modifications to the following areas during the past five years: improvements to increase drive horsepower increased capacity on a main mine feed conveyor, modification of the waste oil system improved waste oil processing; installation of a naphtha recovery unit allowed recovery of naphtha from secondary extraction tailings; final tailings pump house upgrading eliminated a coarse sand transportation bottleneck; water treatment plant instrumentation upgrading provided overall improved reliability of the utilities facilities; upgrades to electrical substations increased power supply reliability; and process changes improved bitumen recovery.

The following table shows daily production and cash operating costs of Oil Sands Group for the years indicated.

	Year ended December 31				
	1991	**1990**(1)	**1989**	**1988**(2)	**1987**(2)
Daily production					
(thousands of barrels)	60.6	52.0	57.2	49.4	44.0
(thousands of m^3)	9.6	8.3	9.1	7.8	7.0
Cash operating costs (3)					
($ per barrel)	15.75	17.25	14.50	15.00	16.75
($ per m^3)	98.50	109.00	91.25	94.75	105.50

(1) In 1990 production was reduced by a 41 day maintenance shutdown.

(2) In 1988 and 1987 production was reduced by a fire in the extraction plant.

(3) Cash operating costs include operating and maintenance costs, overburden cash expenditures and the amortization of maintenance shutdown expenditures, but exclude royalties, capital expenditures, other amortization, head office overhead, interest and net employee housing.

In 1990, the planned maintenance shutdown, which was 41 days and lasted approximately ten days longer than expected, reduced the annual production level and increased cash operating costs per barrel significantly. Excluding the shutdown period, the 1990 production and cash operating costs would have been approximately 60,000 barrels (9,500 m^3) per day and $15 per barrel. On this basis, cash operating costs increased slightly to $15.75 in 1991 from 1990, excluding the plant shutdown period. This increase was a result of dyke repairs, higher amortization of plant shutdown costs and a number of costs associated with improvements related to reliability of boilers and other equipment.

In October 1987, a major fire in the extraction facility forced the shutdown of the plant. Partial operations resumed in January 1988 and full production was restored by late March 1988. Expenditures to clean up, rebuild and make improvements to the extraction plant totalled approximately $60 million. Proceeds totalling approximately $25 million were received under Suncor's insurance claim to partially offset this cost. Steps were taken to reduce the risk of a recurrence by upgrading certain of the operating procedures, equipment and facilities involved. A substantial claim has been brought by Suncor against third parties alleging negligence which resulted in the spread of the fire.

Following the resumption of operations in 1988, efforts were intensified to reduce operating risk. A facility risk review was completed and actions were undertaken immediately to address major risk items at a cost of over $16 million. Oil Sands Group has adapted its ongoing engineering, operating and maintenance programs to reduce similar facility risks in the future.

Improvements introduced to the quality assurance information systems continue to contribute to production by detecting potential equipment failures and determining the appropriate maintenance frequency. In 1991, a major upgrade to one of the main boilers was completed. To be addressed over the next three years are upgrades of the remaining boilers, refurbishing of the electrical substations and improvements to instrumentation systems at a cost of approximately $10 million per annum.

A plan involving a number of specific actions at the plant has been initiated with a view to achieving consistent production of an average of 64,000 barrels (10,175 m^3) per day by 1994. Some of the major projects, largely scheduled for completion during the planned 1993 plant maintenance shutdown, are modification of coker heaters to reduce downtime for decoking, coker unit modifications to control fouling and increase on-stream time, modification of a storage tank to enhance flexibility of pipeline use, improved diluent recovery and reduction of emissions, and installation of a new design of digging head on a bucketwheel excavator to increase reliability and production and decrease maintenance costs. See "Capital Expenditures".

Suncor's mine plan, which includes plans for the optimum recovery of bitumen under the physical, technological, environmental and economic constraints associated with the mining operation, requires approval annually by the Energy Resources Conservation Board of Alberta, which approval is in place for 1992.

Leasehold Interests and Royalties

Suncor's current oil sands mining operations are conducted on a 6,140 acre (2,456 hectare) site covered by two oil sands leases granted by the Province of Alberta known as Lease 86 and Lease 17. Lease 86 and Lease 17 are adjacent and located on the west bank of the Athabasca River, about 20 miles (32 kilometres) north of Fort McMurray. Lease 86 expires in the year 2008, Lease 17 expires in 2000 and each is renewable as long as the plant or other works are in operation. Suncor owns the surface area of the land on which most of its plant facility is located.

Lease 86 covers 4,523 acres (1,809 hectares). At December 31, 1991, approximately 67% of Suncor's proved reserves of synthetic crude oil were located on the property covered by Lease 86. Lease 17 covers 1,617 acres (647 hectares) adjacent to Lease 86. At December 31, 1991, Lease 17 contained approximately 33% of Suncor's proved reserves of synthetic crude oil. In 1991, Lease 86 accounted for 97% of Suncor's production and Lease 17 accounted for 3%. Suncor expects that mining operations on Lease 86 will be completed in approximately eight years with mining operations continuing only on Lease 17 thereafter until approximately 2003.

The Province of Alberta is entitled to royalties under the leases at rates which the Province establishes from time to time. Under the royalty structure, which commenced on July 1, 1987, the royalty paid to the Province of Alberta was calculated as the greater of 2% of revenues or 15% of the sum of revenues minus allowed operating and capital costs. This royalty remained in place until December 31, 1991 when the rate was changed significantly to the greater of 5% of revenues or 30% of the sum of revenues minus allowed operating and capital costs. The royalty is payable in the form of synthetic crude oil, but the Crown may request that Suncor dispose of the Crown share of synthetic crude oil on its behalf and pay the proceeds to the Crown. The Crown currently chooses the latter option. See "Government Regulation".

Until February 28, 1989, Norcen International Ltd. ("Norcen") had a 25% interest in Lease 86 and subleased it to Suncor. To resolve a number of disputes arising out of the sublease royalty arrangement, the parties settled all outstanding claims, terminated the existing sublease arrangement and replaced it with a new gross overriding royalty agreement effective March 1, 1989 (the "Norcen Royalty"). The Norcen Royalty is based on a graduated scale expressed as a percentage of gross revenue from production of the lease. As of December 31, 1991, under the Norcen Royalty, no payment is required if synthetic crude prices are below $17.22 per barrel ($108.31 per m^3). Payment of 1½% of gross revenue is required if the synthetic crude price ranges from $17.22 to $18.22 per barrel ($108.31 to $114.60 per m^3). For every $1.00 per barrel ($6.29 per m^3) increase in the price of synthetic crude in the range of $18.22 to $22.22 per barrel ($114.60 to $139.76 per m^3), the percentage rate of the royalty increases by ½%. For every $1.00 per barrel ($6.29 per m^3) increase in the price of synthetic crude in the range of $22.22 to $34.22 per barrel ($139.76 to $215.24 per m^3), the percentage rate of the royalty increases by a further ¼% until a maximum royalty of 7% is reached. All synthetic crude prices are calculated on a monthly average basis and the crude price break points are adjusted annually on March 1 by a contractually determined inflation component.

Royalties were as follows for the years indicated.

	Year ended December 31				
	1991	**1990**	**1989**	**1988**	**1987**
			($ millions)		
Crown Royalty (1)	10	11	9	9	3
Norcen Royalty (2)	20	29	19	17	22

(1) Payable with respect to Lease 86 and Lease 17.

(2) Payable with respect to Lease 86.

If the Crown royalty in 1991 had been at a rate of 5% instead of the rate of 2% actually incurred, the Crown royalty costs would have been $25 million for 1991.

Suncor also holds Leases 98 and 14 which are two other potentially mineable oil sands leases in the Athabasca area approximately 20 miles (32 kilometres) from the oil sands plant. See "Outlook".

Synthetic Crude Oil Gross Proved Reserves

Suncor engaged Coles Gilbert Associates Ltd. ("CGA"), independent petroleum consultants, to report on its reserves of synthetic crude oil as of December 31, 1991. The independent CGA assessment does not take into account the economic aspects of future production. The reported proved reserves are those considered with a high degree of certainty to be mineable using current and planned future mining methods and are based on the 1982 mine plan adopted by Suncor after considering at that time the engineering and economic aspects of future production.

The estimate of synthetic crude oil reserves incorporates a bitumen grade cutoff and pit limit to which Suncor agreed in the 1982 mining plan in return for various concessions from the Governments of Alberta and Canada. Any future improvements in the extraction and upgrading process have not been considered. Small amounts of bitumen reserves associated with the tailings pond pump project have been included based on a 50% recovery factor. On-site fuel consumption has been deducted. On that basis, CGA determined that the gross proved reserves of synthetic crude oil as of December 31, 1991 were 276 million barrels (43.9 million m^3) before deduction of Crown and applicable sublease royalties.

Production

The following table summarizes Suncor's synthetic crude oil operations for the years indicated.

	Year ended December 31				
	1991	1990(1)	1989	1988(2)	1987(2)
Overburden removed					
(millions of cubic yards)	12.8	12.8	13.0	13.3	15.3
(millions of m^3)	9.8	9.8	9.9	10.2	11.7
Oil sands mined					
(millions of tons)	45.1	39.2	44.1	42.2	36.1
(millions of tonnes)	40.9	35.5	40.1	38.3	32.7
Average bitumen content of oil sands mined					
(% by weight)	11.9	12.0	12.0	11.6	11.9
Average crude yield of oil sands mined					
(barrels per ton)	0.49	0.48	0.47	0.43	0.44
(m^3 per tonne)	0.09	0.09	0.08	0.08	0.08
Partially and fully processed synthetic crude oil production (3)					
(millions of barrels)	22.1	19.0	20.9	18.1	16.0
(millions of m^3)	3.5	3.0	3.3	2.9	2.5

(1) In 1990 production was reduced by a 41 day maintenance shutdown.

(2) In 1988 and 1987 production was reduced by a fire at the extraction plant.

(3) Before royalties and after plant usage.

Revenues from Synthetic Crude Oil

Under an agreement made in 1965 at the outset of the oil sands project, which has been amended from time to time, Shell Canada Products Limited ("Shell") is entitled to purchase approximately 25% plus 2,950 barrels (469 m^3) daily of Suncor's synthetic crude oil production attributable to Lease 86. The agreement remains in force until December 1992 and is renewable, at Shell's option, for further five-year periods. Shell has indicated that it intends to renew the agreement in December 1992. In 1991, 7.0 million barrels (1.1 million m^3) were sold to Shell. The price at which synthetic crude oil is sold to Shell is based on the average price of three Alberta reference crude oils and approximates the price received from other customers. Sales to Shell in 1991 represented approximately ten percent of Suncor's consolidated revenues. Shell is the only customer whose purchases account for 10% or more of the consolidated revenue of Suncor.

A major portion of Suncor's synthetic crude oil production is used in connection with its Sarnia refining operations. During 1991, the refinery processed approximately 45% of Suncor's synthetic crude oil production. The balance, after sales to Shell and the Sarnia refinery, is sold to others under contracts terminable by short notice or on a spot basis.

Total revenue for Oil Sands Group was $519 million in 1991 compared with $537 million in 1990. The following table provides information as to Suncor's synthetic crude oil sales revenues and costs for the years indicated.

	Year ended December 31				
	1991	1990	1989	1988	1987
Average sales revenue of synthetic crude oil (including partially processed)					
($ per barrel)	22.95	28.59	21.08	17.96	23.27
($ per m^3)	144	180	133	113	146
Average cost of synthetic crude oil produced (1)					
($ per barrel)	19.76	22.25	18.44	18.60	20.99
($ per m^3)	124	140	116	117	132

(1) Includes all operating (including non-cash) costs and royalties; excludes head office overhead, interest and net employee housing costs.

Operating costs to produce synthetic crude oil are substantially higher than lifting costs to produce conventional crude oil due to the nature of the operations required to produce synthetic crude oil. The costs associated with synthetic crude are largely fixed due to the mining nature of the operations and as a result, operating costs per unit are largely dependent on levels of production.

Labour Relations

Oil Sands Group employs directly approximately 1,800 people, of whom approximately 1,000 are unionized. Oil Sands Group and the Energy and Chemical Workers Union ("ECWU") are negotiating a new two year collective agreement to replace the one which expires May 1, 1992. Constructive relations exist between the ECWU and management. Based upon discussions to date, management believes that an agreement will be reached prior to the expiration of the current contract.

Suncor also uses the services of various outside contractors to provide contract maintenance support in certain areas of the plant. These contractors employ approximately 450 workers, most of which are unionized in various trades. The collective agreement for the unionized workers of the largest of these contractors expires in 1993.

Outlook

Suncor anticipates that it will have completed mining the reserves on Leases 86 and 17 in approximately 12 years. Suncor is investigating alternatives to permit Oil Sands Group to operate beyond 2003 and is currently engaged in discussions with the Government of Alberta regarding the establishment of a basis for extending the operation.

There are a number of options currently being investigated for the future of the oil sands plant. It could continue to operate as an integrated open pit mining operation, using the significant bitumen in place that is within conveying distance of the plant and existing proven technology. In 1988, Suncor and other leaseholders carried out a joint drilling program on the adjacent leases on the east bank of the Athabasca River. This program confirmed the existence of high quality bitumen leased by others that could extend the existing mining operations by over 30 years. Preliminary engineering work has been completed and indicates that significant expenditures would be required to establish a new mining operation on the east bank of the Athabasca River, to move the oil sand feed by conveyor to the existing extraction and heavy oil upgrading facilities and to meet anticipated future environmental standards.

Other options being investigated include potential new mining technology alternatives such as transportation of oil sands by slurry pipeline, which could be more economically viable than conveying from remote deposits leased by Suncor or others. Various in situ extraction techniques may allow the recovery of bitumen without mining. A number of such technological developments are currently being evaluated by the industry. It may also be possible to supply bitumen to the upgrading facility via pipeline from the various operating commercial heavy oil and in situ heavy oil areas in Alberta.

Under these options, Suncor could continue to be involved in the production and upgrading of bitumen or could function as a heavy oil upgrader processing bitumen produced by others. A long lead time is necessary to interest potential joint venture partners, design the project, obtain regulatory and environmental approvals and ultimately construct the necessary facilities. Suncor intends to pursue these options over the next three years in order to determine the most appropriate and economic course of action.

Consistent with overall strategy to achieve a better balance among the three operating groups, it is unlikely that Suncor would establish a new mining operation on the east bank of the Athabasca River or pursue other options requiring significant capital expenditures without bringing partners into the oil sands operation. Upon completion of discussions with the Government of Alberta, Suncor intends to recommence prior efforts which were carried out in 1989 and 1990 to bring partners into the oil sands operation. Suncor is not currently conducting negotiations with any potential partner. Suncor believes that its improved operational performance over the past number of years, combined with the settlement of an appropriate royalty and fiscal regime and an approved comprehensive environmental plan with the Government of Alberta, will address a number of the concerns raised in its prior discussions with potential partners. See "Environmental Compliance".

A decision to proceed beyond the reserve life on the existing leases will not be made until all outstanding issues are resolved. There can be no assurances that an economically viable option will be developed and implemented.

Capital Expenditures

Continued operation of the oil sands plant requires ongoing capital expenditures. Main feed conveyor systems were extended in 1990 and 1991 at a cost of approximately $36 million and will continue to be extended in 1992, at a cost of approximately $19 million, to allow the current leases to be fully mined under the current mine plan. These extensions are required as mining activities have moved further away from the processing facilities. Equipment, including mobile equipment, must be replaced as it wears out. Suncor anticipates that capital expenditures to maintain production levels will vary between approximately $50 million and $60 million per year and average approximately $55 million (inclusive of conveyor extension costs) for the next five years. These expenditures are made on an on-going basis primarily to refurbish or enhance the plant facilities.

The following table summarizes capital expenditures by Oil Sands Group for the years indicated.

	Year ended December 31				
	1991	1990	1989	1988	1987
			($ millions)		
Extraction plant restoration (fire damage)	—	—	—	28	19
Conveyor extension	34	2	—	—	—
Mine and mobile equipment	19	7	16	4	5
Debottlenecking (increasing capacity)	—	—	3	23	1
Upgrading, utilities and other plant	23	22	22	13	10
Total	76	31	41	68	35

Environmental Compliance

Oil Sands Group has all licences required to operate including a clean water licence and a clean air licence both of which expire on April 1, 1992, and a development and reclamation approval, which expires on April 25, 1995. Oil Sands Group anticipates that all necessary licences will either be renewed or extended upon expiry.

Site reclamation costs at Oil Sands Group have been estimated and are being recorded over the estimated remaining life of the reserves by charges against earnings on a unit of production basis reflecting the cost of the reclamation plan submitted to the Province of Alberta. The reclamation plan is comprehensive and includes the tailings ponds reclamation, plant decommissioning and all surface reclamation and remediation at the site. The plan includes moving the fine tailings and the water in the four active tailings ponds and pumping drainage water to a fifth pond designed for these purposes, filling in the four original ponds with coarse tailings sand and rehabilitating these areas. Based on small scale testing to date, biological processes are expected to cleanse the water in the fifth pond so that it will eventually support aquatic life. Oil Sands Group is currently conducting research and development to demonstrate and verify results from pilot testing on a substantially larger scale.

While the proposed method of reclamation for the cleansing of the water in the fifth tailings pond has not yet been demonstrated on a large scale, Oil Sands Group expects to demonstrate the viability of this method of reclamation prior to the renewal of its development and reclamation approval in 1995. Oil Sands Group is also developing methods to improve bitumen recovery which will decrease the amount of hydrocarbons discharged into the tailings ponds. Oil Sands Group also plans to recover bitumen from the active tailings ponds when the fine tailings in the ponds are transferred to the fifth pond. As part of its reclamation plan, Oil Sands Group engages in ongoing surface reclamation involving both replacement of muskeg and revegetation.

Oil Sands Group estimates that the total cost for reclamation of the site will be approximately $230 million (1991 dollars). This estimate is based on the current development and reclamation approval which will expire in 1995. Further groundwater and soil testing is planned to more accurately determine the extent and cost of portions of the reclamation plan. If such testing reveals additional contamination requiring remediation, or more stringent regulatory requirements are imposed, or the proposed method of reclamation for the cleansing of the water in the fifth tailings pond is not viable, the reclamation costs could increase significantly.

Suncor's 1991 earnings reflect a before tax charge of approximately $11 million for future reclamation costs. As of December 31, 1991, approximately $100 million of the estimated $230 million reclamation costs has been accrued in Suncor's consolidated financial statements.

Oil Sands Group is holding discussions with the Government of Alberta regarding compliance with existing and anticipated environmental laws pertaining to air emissions and water discharges. These discussions have focused on two possible scenarios: measures necessary to continue to operate the site until the existing reserves have been mined (approximately 12 years), and measures necessary to continue to operate during and beyond the life of the current reserves (approximately 30 years). See "Outlook". The measures being discussed relate primarily to the reduction of sulphur dioxide and odour emissions. Regulatory changes are anticipated in the Province of Alberta as a result of agreements among the western provinces and the federal government on acidification standards.

Oil Sands Group has estimated the cost necessary to ensure that it complies with existing and anticipated environmental laws pertaining to air emissions and water discharges for each of the two scenarios discussed above, and has reviewed its cost estimates with the Government of Alberta. Oil Sands Group has estimated the cost for the first scenario (approximately 12 years of operation) to be approximately $30 million (1989 dollars) and for the second scenario (approximately 30 years of operation) to be approximately $230 million. Estimates for these two scenarios provided by the Government of Alberta are approximately $70 million (1989 dollars) and $250 million (1989 dollars), respectively. Suncor cannot predict the nature or timing of any future regulatory requirements. Oil Sands Group is discussing future regulatory requirements with the Government of Alberta.

Oil Sands Group has experienced some problems meeting sulphur dioxide and hydrogen sulphide ambient air guidelines. Oil Sands Group has and is continuing to address such problems through process and plant modifications. In 1991, new technology aimed at reducing sulphur dioxide emissions from the oil sands plant was evaluated in a pilot plant. The results of the evaluation will be known early in 1992. Preliminary results demonstrate that the new technology is technically viable. Economic evaluations of this technology are being conducted.

In 1991, Oil Sands Group received an emission control order from the Province of Alberta in response to odour emanating from the tailings ponds. Oil Sands Group is complying with the order by monitoring sources of odour emissions and using the monitoring results to develop a solution to this problem. Implementation of changes over the next few years in diluent quality and improved capability for diluent recovery are expected to result in reductions in odour emissions. Although not all the odours are expected to be eliminated, the potential for odour incidents should be significantly reduced.

See "Government Regulation — Environmental Regulation".

RESOURCES GROUP

Suncor is active in the exploration, acquisition and development of crude oil and natural gas in Canada and the marketing of natural gas in North America through Resources Group. Suncor's strategy is to significantly increase its reserve and production base within the next five years and to improve the quality of its asset base by enhancing reservoir recoveries, by divesting properties that are no longer a strategic fit and by improving the overall effectiveness and efficiency of its organization. Suncor concentrates on conventional crude oil and natural gas activities in western Canada with increasing emphasis on natural gas. Additionally, in situ recovery methods will be evaluated and where economically viable used to enhance heavy oil production capabilities.

The following table sets forth earnings, cash provided from operating activities and capital and exploration expenditures of Resources Group for the years indicated.

	Year ended December 31				
	1991	1990	1989	1988	1987
			($ million)		
Earnings (loss)	4	18	7	(41)	(1)
Cash provided from operating activities	76	82	56	35	58
Capital and exploration expenditures	118	97	58	95	77

Since deregulation of crude oil prices in 1985, Resources Group has taken action to improve its competitive position by reducing the size of its exploration program and focusing on fewer areas. Finding costs decreased from an average of $11.18 per BOE in the years 1986 to 1988 to an average of $4.54 per BOE in the years 1989 to 1991.

Since 1986, Resources Group has sold or farmed out its non-oil and gas mineral assets as well as reduced its oil and gas portfolio from over 275 properties to approximately 140 properties, while concurrently increasing production on a BOE basis by 12 %.

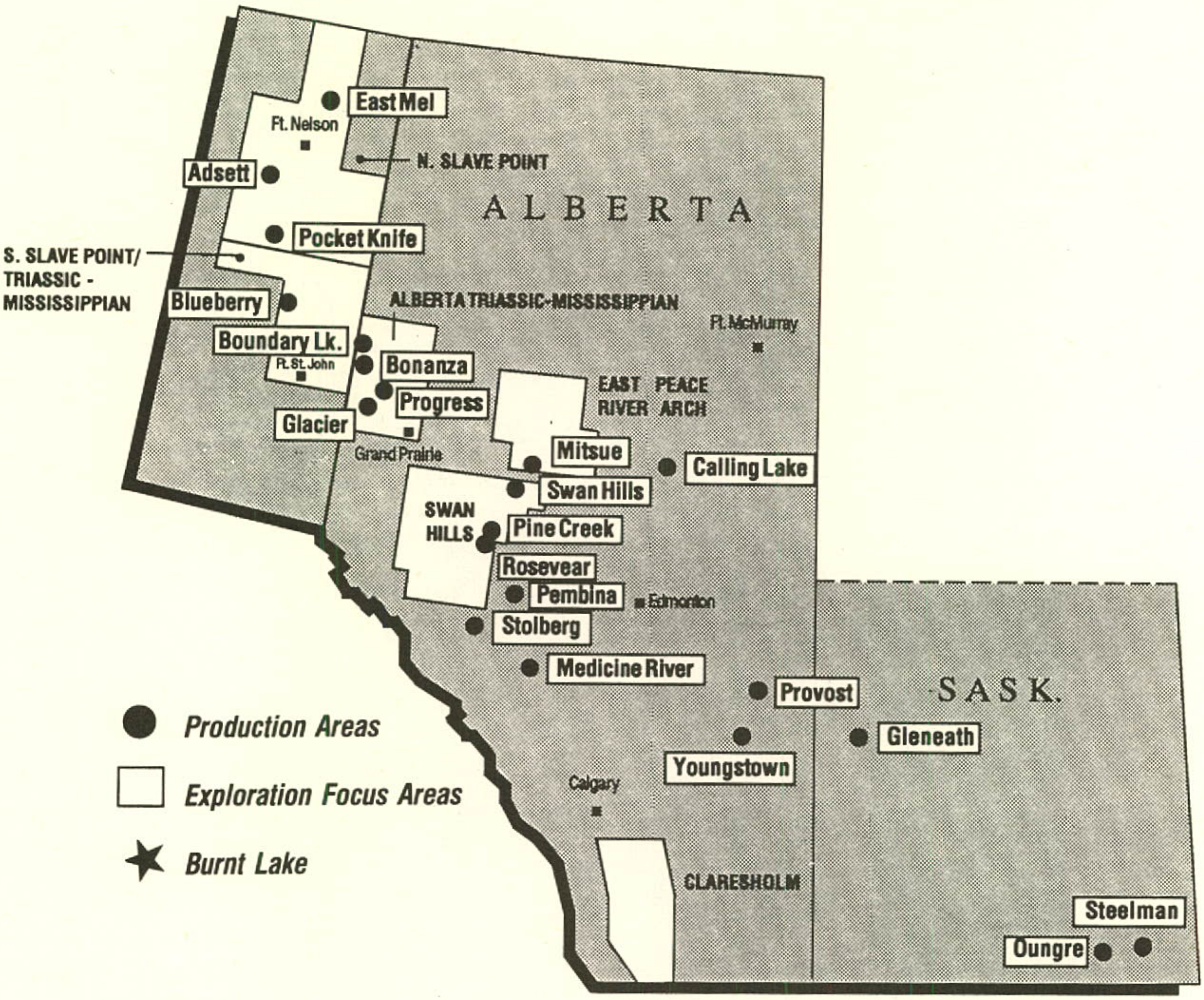
A natural gas marketing function was established in 1986 enabling Resources Group to develop in-house direct marketing expertise to exploit opportunities resulting from deregulation of natural gas in 1985. The gas marketing group sells natural gas acquired from other producers in addition to Suncor's natural gas production.

Resources Group also reduced its administrative costs by reducing management layers and decreasing its employee base from approximately 620 in 1986 to approximately 250 employees in 1991. Through these efforts, the lifting and administrative costs of Resources Group declined from $8.40 per BOE in 1986 to $6.16 per BOE in 1991 and productivity increased from 31 BOE per employee per day to 88 BOE per employee per day over the same period. Such unit costs are expected to further decline in 1992 as more natural gas production comes on stream. Management believes that Resources Group is capable of operating a significantly larger property portfolio with minor increases in overhead costs. Suncor believes that it currently enjoys certain competitive advantages because it recognized the changing environment in the oil and gas industry earlier than many of its competitors which are currently executing similar rationalization initiatives. The early recognition of the need for these rationalization initiatives resulted in lower administrative costs over the past two years and the sale of properties from 1986 to 1988 in a more favourable market. Improved exploration results have been achieved due to a geographically focussed program commencing in 1986 and an active acquisition effort commencing in 1990 in a depressed market which further allows Resources Group to lower per unit overhead costs.

During 1990 and 1991, Resources Group continued to add selectively to its crude oil and natural gas portfolio. In total, the acquisition and exploration programs added proved and probable reserves equalling more than 240% of Resources Group's 1990 production on a BOE basis and more than 240% of Resource Group's 1991 production on a BOE basis.

Exploration and Development

The following map indicates Resources Group's major exploration and production areas.



Over the last two years, Resources Group spent approximately $210 million on its exploration, acquisition and development program directed towards developing large natural gas and light crude oil prospects. Exploration has been focused in selected areas. In this way, the productivity of the exploration teams and the ability to develop a competitive advantage in a given region are enhanced. During 1991, the exploration program found gross proved and probable reserves of approximately 3.4 million BOE which represented 43% of 1991 production. Finding costs based on a three year rolling average are as follows: 1991 — $4.54; 1990 — $5.23; 1989 — $7.46; 1988 — $11.18; 1987 — $8.67. In 1991, the number of wells drilled was lower than expected due to delays resulting from warm weather in the winter which made it difficult to gain access to certain lands and failure to obtain certain joint venture approvals.

Natural gas exploration is concentrated in the Slave Point/Keg River formations of northern Alberta and northeast British Columbia, in the Triassic/Mississippian reservoirs located in the Peace River Arch areas of Alberta and British Columbia and in the Swan Hills formation of central Alberta. Oil exploration is focused on the Triassic and Devonian formations in northwest Alberta and northeast British Columbia. In late 1991, Resources Group commenced drilling on a large farm-in in the Claresholm area in southern Alberta, where it is searching for light low sulphur crude oil with horizontal drilling technology.

During 1991, Suncor participated in the drilling of 27 gross exploration wells (15 net). Oil and gas was found in nine gross wells (five net) for a success rate of 33%. In addition, Resources Group farmed out 28 prospects on which 13 oil and gas discoveries were made by others. Suncor retains varying interests in these discoveries.

No wells were drilled on Resources Group's frontier lands in 1991. Suncor continues to hold interests in frontier properties, including 27 long term "significant discovery licences", which have uneconomic resources of 1.5 trillion cubic feet (40 billion m^3) of natural gas and 50 million barrels (7.9 million m^3) of oil. See "Government Regulation — Frontier Areas". Suncor has no plans to develop these resources in the foreseeable future.

In October 1991, Suncor acquired additional major interests in the two Rosevear fields near Edson, Alberta, in exchange for minor interests in six unitized fields, the assumption of a take or pay obligation of approximately $7 million and a cash payment of approximately $24 million. This acquisition increased Suncor's proved reserves on a BOE basis by 10% and increased natural gas production by 20%. By consolidating Suncor's interests in the area, Suncor is likely to reduce operating costs significantly.

In addition, in 1991 Suncor purchased additional interests in the Pocketknife and Glacier fields in northeast British Columbia and northwest Alberta, respectively, for $7 million. Several smaller acquisitions were also made in 1991. In 1990, Suncor acquired interests in East Mel, Pocketknife and Adsett in northeast British Columbia and in Glacier at a cost of approximately $25 million.

In 1991, Suncor's major development programs in Alberta included bringing into production wells in Bonanza, infill drilling programs in Pembina and Youngstown, drilling and building facilities at Pine Creek and gas gathering system and road construction and drilling in Glacier. Reserves totalling 7.7 million BOE were added to the proved producing category through these development programs.

In February 1992, Suncor signed an agreement with another party to purchase the other party's interest in oil and gas properties located in central Alberta for a price which would represent a substantial portion of Resources Group's acquisition budget of approximately $50 million for 1992. Completion of the transaction is subject to various conditions including waiver of third party rights of first refusal and settlement of definitive agreements acceptable to both parties.

Conventional Oil

The following table shows estimates of Suncor's proved crude oil reserves before royalties as prepared by CGA (see "Reserves") and Suncor's average daily production of crude oil before royalties represented by the major conventional oil fields identified in the table. The fields specified in the table represent over 65% of Suncor's proved reserves and gross production.

Fields	Proved Reserves Before Royalties at December 31, 1991		1991 Average Daily Production Before Royalties	
	(millions of barrels)	(%)	(barrels of oil per day)	(%)
Oungre	5.2	17	910	9
Medicine River	4.2	14	1,400	14
Pembina	2.5	8	518	5
Swan Hills	2.0	7	430	4
Youngstown	2.0	7	1,444	15
Steelman	1.8	6	416	4
Provost	0.9	3	720	8
Blueberry	0.9	3	168	2
Boundary Lake	0.9	3	220	2
Mitsue	0.8	3	305	3
Gleneath	0.7	2	129	1
Other (1)	8.2	27	3,350	33
	30.1	100	10,010	100

(1) Includes fields in which Suncor holds overriding royalty interests.
(2) The reserves and production in this table do not include natural gas liquids.
(3) For metric equivalent data see "Supplementary Tables — Table 1".

Most of the large conventional oil fields in the western provinces have been in production for a number of years and the rate of production in these fields is naturally declining. Suncor expects new discoveries by the industry to be smaller and to have higher finding costs than in the past. In some cases, additional amounts of crude oil can be recovered by using various methods of enhanced oil recovery, infill drilling and production optimization schemes.

The most commonly used enhanced oil recovery mechanism is waterflooding where water is injected into the reservoir to pressurize the formation. Waterflood programs are used in eight of Suncor's top 11 oil producing fields. At Mitsue and Swan Hills, Alberta sophisticated miscible flooding is employed involving high pressure natural gas and solvent injection into the reservoir. At the end of 1991, approximately 73% of Suncor's proved conventional oil reserves were under enhanced oil recovery programs.

Some reserves are capable of production using primary methods which utilize the reservoir's natural pressure. Primary recovery methods are used at three of Suncor's top 11 producing fields. Suncor has employed horizontal and directional drilling techniques in order to increase oil recovery, reduce development costs and minimize environmental disturbance. Horizontal drilling techniques have been applied at the Oungre field in Saskatchewan and to a lesser extent at Provost, Alberta and Hoffard, British Columbia. Suncor plans to continue to apply this technology where technically and economically feasible.

Natural Gas

During the past five years, Suncor has focused its exploration, development and acquisition programs on increasing natural gas production. As a result, natural gas production has more than doubled and several significant producing properties have been added to the portfolio. In order to increase or maintain production levels in certain of the more mature fields, compression facilities have been constructed.

The following table shows estimates of Suncor's proved natural gas reserves before royalties as prepared by CGA (see "Reserves") and Suncor's average daily production before royalties represented by the major natural gas fields identified in the table. The fields specified in the table represent 50% of Suncor's proved reserves and gross production.

Fields	Proved Reserves Before Royalties at December 31, 1991		1991 Average Daily Production Before Royalties	
	(billions of cubic feet)	(%)	(millions of cubic feet per day)	(%)
Rosevear	99	20	20.6	20
Glacier (1)	53	11	—	—
Stolberg	42	9	3.2	3
Pine Creek	34	7	4.6	4
Adsett (1)	26	5	—	—
Bonanza	24	5	1.8	2
Blueberry	24	5	1.4	1
East Mel	15	3	4.8	4
Pocketknife	11	2	5.9	6
Progress	11	2	6.0	6
Calling Lake	10	2	4.8	4
Other (2)	141	29	51.9	50
	490	100	105.0	100

(1) Scheduled to commence production in 1992.
(2) Includes fields in which Suncor holds overriding royalty interests.
(3) For metric equivalent data see "Supplementary Tables — Table 1".

Suncor operates the Rosevear South, Rosevear North, Pine Creek, Thorsby and Liege processing plants with a total design capacity of approximately 135 million cubic feet (3.8 million m^3) per day. Suncor also has varying working interests in other natural gas processing plants and field gas gathering facilities operated by other companies and processes gas at third party plants. During 1991, Suncor purchased and assumed operatorship of the Rosevear South plant and started development work on the gas facilities at Adsett and Glacier, which are expected to commence production of approximately 16 million cubic feet (0.5 million m^3) per day by November 1992.

Non-Conventional Heavy Oil

In 1985, Suncor purchased the right to farm into 48 sections of oil sands leases called the Burnt Lake Heavy Oil Project in the Cold Lake area of Alberta for $79 million. In 1986, a project was commenced and Suncor earned a 79.1% working interest in four sections of oil sands leases. These sections were chosen for their relatively high reservoir quality. Suncor believes Burnt Lake is one of the highest quality non-conventional heavy oil reservoirs in Canada. The project was suspended that same year due to falling heavy oil prices. Work resumed on the development of a steam in situ recovery project in 1988 but was again suspended in 1989 in response to lower and uncertain heavy oil prices. During 1990 and 1991, approximately $4 million was spent on testing "cold" production technology and other associated activities for potential use in the project. Cold production technology involves the use of a screw pump which augers oil and sand to the surface. As a lower pressure zone is created around the well bore, the pump system brings the viscous heavy oil and sand to the surface. In 1991 the total production of four wells averaged in excess of 400 barrels (64 m^3) per day using cold production technology. This production was well above the anticipated recoveries from steam stimulation wells. Given the unknown nature of this new technology, the level of production finally obtained will not be known until all testing is fully complete and assessed. Three of the four wells have produced encouraging volumes, but the results are not uniform across the reservoir. A further eight wells will be tied in and tested in 1992. Depending upon the results and a reassessment of other options, staged development could continue in the future.

The project is highly sensitive to heavy oil prices and development and lifting costs. Management expects a memorandum of understanding with the Alberta government on a royalty structure will be signed and the earnings provisions of the farm-in agreement will be modified to encompass the cold production technology. Suncor's estimate of recoverable heavy oil using a 20% recovery factor of the oil-in-place is over 250 million barrels (39.7 million m^3). Suncor's decision to proceed with the project, which would enable it to earn a 79.1% working interest in the remaining 44 sections of the Burnt Lake oil sands lease, will require confidence in higher and sustained heavy oil prices and sufficiently low capital and operating costs to make the project commercially viable. If the project is not commercially viable, the $141 million book value of the project as at December 31, 1991 may need to be written down in whole or in part.

Resources Group has various interests in heavy oil leases in Cold Lake and the Athabasca regions of Alberta with uneconomic heavy oil resources of 19 billion barrels (3.0 billion m^3). These properties have little or no book value. Suncor has no current plans to develop any of these leases and does not have the necessary technology to extract heavy oil on an economic basis.

Land Holdings

The following table sets forth the undeveloped and developed lands in which Resources Group held petroleum and natural gas interests at the end of 1991 and 1990, except as indicated in notes (3) and (4) below. Undeveloped lands are lands on which no producing well or well capable of production has been drilled and developed lands are lands on which such a well has been drilled.

	Licences, Reservations, Permits and Exploration Agreements (1)				Leases (1)			
	Gross Acres (2)		Net Acres (2)		Gross Acres (2)		Net Acres (2)	
	1991	1990	1991	1990	1991	1990	1991	1990
	(thousands)				(thousands)			
Undeveloped Lands								
Western Provinces (3)								
British Columbia	123.2	72.4	84.9	47.7	154.3	137.3	92.2	78.1
Alberta (4)	398.3	283.6	206.2	161.3	426.0	287.5	213.2	165.0
Saskatchewan	60.5	60.5	60.4	60.3	15.6	23.5	7.2	12.1
Manitoba	—	—	—	—	—	2.5	—	2.5
Total	582.0	416.5	351.5	269.3	595.9	450.8	312.6	257.7

	Licences, Reservations, Permits and Exploration Agreements (1)				Leases (1)			
	Gross Acres (2)		Net Acres (2)		Gross Acres (2)		Net Acres (2)	
	1991	1990	1991	1990	1991	1990	1991	1990
	(thousands)				(thousands)			
Frontier (Canada Lands)								
Northwest Territories	47.4	47.4	35.5	35.6	—	—	—	—
Mackenzie Delta	—	—	—	—	6.7	6.7	3.0	3.0
Beaufort Sea	241.9	675.5	12.6	34.8	34.6	34.6	3.7	3.7
Arctic Islands	—	—	—	—	391.7	391.7	55.7	55.7
Offshore Labrador	—	—	—	—	62.2	62.2	6.2	6.2
Total	289.3	722.9	48.1	70.4	495.2	495.2	68.6	68.6
Developed Lands								
Western Provinces (3)								
British Columbia	2.6	0.3	1.8	0.2	129.4	127.5	45.9	45.0
Alberta (4)	10.0	8.6	3.9	3.2	801.7	671.6	347.4	372.0
Saskatchewan	—	—	—	—	26.9	31.2	21.6	26.4
Manitoba	—	—	—	—	2.6	1.5	1.4	1.4
Total	12.6	8.9	5.7	3.4	960.6	831.8	416.3	444.8
Frontier (Canada Lands)								
Northwest Territories	—	—	—	—	14.0	14.0	14.0	14.0
Mackenzie Delta	—	—	—	—	7.1	7.1	2.8	2.8
Total	—	—	—	—	21.1	21.1	16.8	16.8

(1) No deduction has been made from Crown licences, reservations, permits or exploration agreements to reflect that only a portion of these areas may be converted to lease or production licence. Crown licences, reservations and permits are acquired from the provincial governments through competitive bidding and exploration agreements are acquired from the federal government by undertaking work commitments. These confer upon the holder exploration rights and the right to lease or apply for a production licence for the crude oil and natural gas rights under portions of the lands covered. The extent of such rights differs in each jurisdiction and between various areas in a single jurisdiction. The holder is generally required to make cash payments or undertake specified work in order to retain such rights. Leases in general confer upon the lessee the right to explore for and remove crude oil and natural gas from the property with the lessee paying all the development and operating costs and being entitled to the production, subject to rental, tax and royalty.

(2) "Gross acres" means all acres in which Suncor has an interest. "Net acres" means gross acres after deducting interests of others.

(3) Includes 276,882 gross developed acres and 18,732 gross undeveloped acres (1990 — 224,227 and 8,483) in western Canada in which Suncor held overriding royalty interests at the end of the years indicated and from which it received revenues of about $3.1 million in 1991 and $3.7 million in 1990.

(4) Not included in the table are the oil sands (including non-conventional heavy oil) leases comprising 221,876 gross (148,136 net) undeveloped acres and 68,666 gross (7,654 net) developed acres at the end of both years.

(5) For metric equivalent data see "Supplementary Tables — Table 2".

Certain of Suncor's interests in undeveloped lands are subject to reduction under farm-out agreements whereby others may earn interests by undertaking exploration or development work. Conversely, Suncor is a party to farm-in agreements whereby it may earn interests in land held by others by undertaking such work.

Drilling

The following table sets forth the gross and net exploratory and development wells which were completed, capped or abandoned in which Suncor participated during the years indicated, all in western Canada.

	Year ended December 31									
	1991		1990		1989		1988		1987	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells										
Oil	3	2	6	4	6	3	18	8	20	9
Gas	6	3	7	4	2	1	4	2	3	2
Dry	18	10	12	7	19	11	38	18	17	9
Total	27	15	25	15	27	15	60	28	40	20
Development Wells										
Oil	74	23	51	13	63	22	81	24	80	21
Gas	11	6	8	6	3	1	5	4	7	4
Dry	9	3	11	7	9	3	13	8	8	3
Total	94	32	70	26	75	26	99	36	95	28
Total	121	47	95	41	102	41	159	64	135	48

Not included are wells completed under farm-out agreements on Suncor properties, since Suncor did not incur cash expenditures in connection with such wells. In addition to the above wells, Suncor had interests in 4.0 gross (2.1 net) exploratory wells in progress at the end of 1991.

Reserves

CGA has reported on Suncor's reserves of crude oil, natural gas and natural gas liquids. The following table sets forth CGA's determination of Suncor's estimated recoverable reserves based on constant year end prices and costs with no escalation into the future as of the dates indicated. The accuracy of any reserve estimate is a function of the quality and quantity of available data and of engineering interpretation and judgment. While reserve and production estimates presented in this prospectus are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

	Gross		Net	
	Crude oil and natural gas liquids (millions of barrels)	Natural gas (billions of cubic feet)	Crude oil and natural gas liquids (millions of barrels)	Natural gas (billions of cubic feet)
Proved:				
December 31, 1989	42	360	35	303
Revisions	1	8	1	3
Acquisitions	1	50	1	42
Other additions	2	21	1	18
Production	(4)	(32)	(3)	(26)
Sales	—	(3)	—	(3)
December 31, 1990	42	404	35	337
Revisions	(1)	(9)	(1)	(10)
Acquisitions	2	103	1	86
Other additions	3	32	2	26
Production	(4)	(38)	(3)	(30)
Sales	(3)	(2)	(2)	(2)
December 31, 1991	39	490	32	407

	Gross		Net	
	Crude oil and natural gas liquids (millions of barrels)	Natural gas (billions of cubic feet)	Crude oil and natural gas liquids (millions of barrels)	Natural gas (billions of cubic feet)
Proved Producing:				
December 31, 1989	38	223	32	185
Revisions	1	21	—	14
Acquisitions	—	29	—	24
Other additions	1	3	1	2
Production	(4)	(32)	(3)	(26)
Sales	—	(2)	—	(2)
December 31, 1990	36	242	30	197
Revisions	—	20	—	19
Acquisitions	1	76	1	63
Other additions	2	11	2	9
Production	(4)	(38)	(3)	(30)
Sales	(2)	(2)	(2)	(2)
December 31, 1991	33	309	28	256
Probable additional:				
December 31, 1990	17	227	14	185
December 31, 1991	16	240	13	198

(1) Proved reserves are those reserves estimated as recoverable under current technology and existing economic conditions, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.

Proved producing reserves are those proved reserves that are actually on production or, if not producing, that could be recovered from existing wells or facilities and where the reason for the current non-producing status is the choice of the owner rather than the lack of markets or some other reason. An illustration of such a situation is where a well or zone is capable of production but is shut-in because its deliverability is not required to meet contract commitments.

Probable additional reserves are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

(2) Gross reserves represent the aggregate of Suncor's working interest in reserves including the royalty interest of governments and others in such reserves and Suncor's royalty interest in reserves of others. Net reserves are gross reserves less the royalty interest share of others including governments. Royalties can vary depending upon selling prices, production volumes, timing of initial production and changes in legislation. Net reserves have been calculated, following generally accepted guidelines, on the basis of prices and the royalty structure in effect at year end and anticipated production rates. Such estimates by their very nature are inexact and subject to constant revisions.

(3) No amounts have been included for non-conventional reserves.

(4) For metric equivalent data see "Supplementary Tables — Table 3".

Production

The following table sets out Suncor's gross and net production during the years indicated. Gross production is that attributable to Suncor's share of production before deduction of applicable royalties and interests owned by others. Net production is gross production less such royalties and other interests.

	Year ended December 31									
	1991		1990		1989		1988		1987	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Crude Oil (thousands of barrels)										
Alberta	2,475	2,056	2,667	2,202	2,687	2,245	2,994	2,502	2,970	2,479
British Columbia	293	254	277	220	239	195	283	233	270	214
Saskatchewan	818	607	855	616	855	610	1,258	944	1,472	1,069
Manitoba	67	53	69	57	75	57	88	63	94	69
Total	3,653	2,970	3,868	3,095	3,856	3,107	4,623	3,742	4,806	3,831
Natural Gas Liquids, (thousands of barrels)										
Alberta	470	352	403	296	359	270	403	308	258	189
British Columbia	33	27	25	18	18	13	18	18	25	19
Saskatchewan	1	1	—	—	—	—	—	—	6	6
Total	504	380	428	314	377	283	421	326	289	214
Total Liquids	4,157	3,350	4,296	3,409	4,233	3,390	5,044	4,068	5,095	4,045
Natural Gas (millions of cubic feet)										
Alberta	32,161	24,844	28,569	22,288	29,279	22,856	27,860	22,288	21,153	17,071
British Columbia	5,952	5,384	3,514	3,123	1,349	1,171	1,100	958	1,384	1,207
Saskatchewan	213	193	284	248	213	177	319	248	390	319
Total	38,326	30,421	32,367	25,659	30,841	24,204	29,279	23,494	22,927	18,597

(1) For metric equivalent data see "Supplementary Tables — Table 4".

As of December 31, 1991, Suncor had interests in 3,687 gross (479 net) producing oil wells in 64 oil fields. Of the gross wells, 1,934 gross (209 net) were in Alberta, 1,133 gross (218 net) in Saskatchewan, 309 gross (30 net) in British Columbia and 311 gross (22 net) in Manitoba. Suncor had interests in 355 gross (82 net) natural gas wells in 76 gas fields. Of the gross wells, 322 gross (75 net) were in Alberta, 11 gross (5 net) were in British Columbia and 22 gross (2 net) were in Saskatchewan at the end of 1991. At the end of the year, 648 gross oil wells and 151 gross gas wells were shut-in.

Sales and Sales Revenues

In 1991, total revenue for Resources Group was $139 million, consisting of $75 million from conventional oil and natural gas liquid sales, $50 million from natural gas sales, $9 million from pipeline revenue and $5 million from other sales. This compares to total revenue of $151 million in 1990, consisting of $97 million for conventional oil and natural gas liquids sales, $46 million for natural gas sales, $7 million for pipeline revenue and $1 million from other sales. The following table shows sale prices and lifting costs in connection with Suncor's conventional crude oil and natural gas operations for the years indicated.

	Year ended December 31				
	1991	1990	1989	1988	1987
Average sales price					
Crude oil ($ per barrel)	20.59	25.03	19.26	15.95	21.33
Crude oil and natural gas liquids ($ per barrel)	19.86	24.48	18.60	15.42	20.83
Natural gas ($ per thousand cubic feet)	1.31	1.43	1.28	1.41	1.48
Average lifting costs of oil and gas ($ per equivalent barrels of gross production) (1)(2)	3.63	3.54	3.50	4.00	3.97
Average sales price					
Crude oil ($ per m^3)	130	157	121	100	134
Crude oil and natural gas liquids ($ per m^3)	125	154	117	97	131
Natural gas ($ per thousand m^3)	46	51	45	50	52
Average lifting costs of oil and gas ($ per equivalent m^3 of gross production) (1)(2)	23	22	22	25	25

(1) Lifting costs include all expenses related to the operation and maintenance of producing or producible wells, gas plants and gathering systems. Such costs do not include royalties, depreciation and depletion, selling, general and administrative expenses and income taxes.

(2) Computed under the relative long term economic relationship method whereby a volume of natural gas is equated to an equivalent volume of crude oil at 10:1.

(3) For equivalent data computed under the relative energy content method see "Supplementary Tables — Table 5".

Suncor's crude oil production is used in its refining operations, exchanged for other crude oil with Canadian or U.S. refiners or sold to Canadian and U.S. purchasers, including certain subsidiaries of Sun Company, Inc. ("Sun"). Sales are generally made under contracts which are terminable by relatively short notice or on a spot basis.

Gas Marketing, Pipeline and Other Operations

Prior to deregulation of the Canadian natural gas industry in 1985, western Canadian natural gas production was sold primarily to large supply aggregators for resale into eastern Canadian and U.S. markets ("system sales"). With deregulation, it became feasible for producers to make sales arrangements directly with the end user ("direct sales").

Resources Group's natural gas production developed prior to 1986 is generally sold under long-term system sales contracts. Proceeds received by producers under these sales arrangements are determined on a net-back basis, whereby each producer receives revenue equal to its proportionate share of sales less regulated transportation charges and a marketing fee. Most of Resources Group's system sales volumes are contracted to TransCanada Pipelines Limited and Pan-Alberta Gas Ltd. These companies resell this natural gas primarily to eastern Canadian and midwest and eastern U.S. markets.

Suncor also entered into a long term contract with Alberta and Southern Gas Co. Ltd. ("A&S") for the sale of natural gas commencing in 1990 into the California market. A&S resells most of its supply to a natural gas transmission company which resells to a large public utility serving northern California. Contracts between Canadian producers and A&S have been the focal point of regulatory attention by the California Public Utilities Commission ("CPUC") which regulates public utilities in that state. The CPUC is of the belief that utility ratepayers in California would be in a better position if the utility purchased a greater percentage of its natural gas requirements directly from Canadian producers under short-term contracts rather than through A&S under long term supply arrangements. This could lower the average price of Canadian natural gas sold into the California market. Canadian producers believe that a reduction of purchases by the utility would be inconsistent with contracts that are in place relative to A&S supply. This issue is the subject of negotiations between producers, A&S, the utility, regulators, and various levels of government in both Canada and the U.S. Since Suncor has only a minor A&S contract, the impact of this issue is not material to Suncor's earnings.

Resources Group recognized that through deregulation it had the opportunity to expand its proprietary sales of natural gas, to exercise greater control of distribution to the U.S. market in anticipation of an over-supply of gas in Canada and to diversify its market risk. As a result, direct natural gas marketing has been a priority for Resources Group since 1986. In 1991, direct gas sales represented 79% of Resources Group's total natural gas sales, including brokered sales.

Resources Group's natural gas production developed after 1985 is generally marketed under direct sales arrangements to customers in eastern Canada and the U.S. midwest. Contracts for these direct sales arrangements are generally for a term of one year and incorporate pricing which is either fixed over the term of the contract or determined on a monthly basis in relation to a specified market reference price. The pricing reference for direct sales to eastern Canadian customers is usually the Alberta border at Empress, Alberta, with the customer being responsible for the transportation of the purchased volume from the point of sale to its facility. The price reference for sales to Resources Group's midwest U.S. customers is usually the terminus of the Northern Border Pipeline at Ventura, Iowa. Resources Group is responsible for transportation arrangements to this point of sale.

To ensure ongoing direct sales access to U.S. markets, Resources Group has entered into several long-term pipeline transportation contracts. Suncor contracted for 50 million cubic feet (1.4 million m^3) per day of firm capacity on the Northern Border Pipeline for a 15 year term which commenced November 1, 1988. In 1989, Suncor negotiated rights to contract for an additional 50 million cubic feet (1.4 million m^3) on this pipeline when it is expanded (completion is expected for November 1992).

In 1991, Resources Group also contracted for approximately 40 million cubic feet (1.1 million m^3) per day on the Pacific Gas Transmission ("PGT") proposed pipeline expansion and related facilities to access markets in California. The PGT contract covers a term of 30 years commencing upon completion of the expansion project (expected for the fourth quarter of 1993). The PGT pipeline expansion is under construction and is one of two projects that are being proposed to increase the capacity for export of Canadian natural gas to the California market. Suncor believes that only one pipeline project is required at this time to meet projections for incremental demand in the target market areas, and that the PGT project is the more attractive of the two alternatives for Suncor and will provide greater market access within California. An informational review of the two projects has been called by the Government of Alberta and may have an influence on the development of one or both projects.

Suncor consumes a significant volume of natural gas in its oil sands plant at Fort McMurray and in its Sarnia refinery. Resources Group contracts for the supply of natural gas to each facility. Natural gas consumption for the oil sands plant in 1991 was 20.7 million cubic feet (0.6 million m^3) per day and in 1990 was 21.4 million cubic feet (0.6 million m^3) per day. Natural gas consumption for the refinery in 1991 was 23.1 million cubic feet (0.7 million m^3) per day and in 1990 was 17.7 million cubic feet (0.5 million m^3) per day.

The Albersun pipeline is a facility owned and operated by Suncor, which was originally constructed in 1968 to transport natural gas to the oil sands plant. It extends approximately 180 miles (288 kilometres) south of the plant and connects with the NOVA intraprovincial pipeline system. The Albersun pipeline has the capacity to move in excess of 100 million cubic feet (2.8 million m^3) per day of natural gas. Suncor contracts and controls most of the gas on the system under delivery based contracts. The pipeline moves gas both north and south for Suncor and other shippers. In 1991, throughput on Albersun was 96 million cubic feet (2.7 million m^3) per day and transportation and compression revenues were $8.7 million.

Resources Group arranges for the marketing of its own sulphur production as well as sulphur production from Suncor's Oil Sands Group. In 1991 production from the two groups totalled 174.8 thousand long tons (177.6 thousand tonnes) and generated gross revenues of $13.7 million. Suncor's sulphur is sold into markets in Canada, the U.S. and offshore. Offshore sales in 1991 were managed under an agency relationship by Petrosul International Ltd. Offshore sales in the last half of 1992, will be arranged through Prism Sulphur Corporation, a producer owned consortium of which Suncor was a founding member.

The following table summarizes the volumes of gas marketed directly or indirectly by Resources Group for the years indicated.

	Year ended December 31				
	1991	1990	1989	1988	1987
	(millions of cubic feet per day)				
Sales for Suncor's Own Account (Proprietary):					
System	39.5	34.0	36.5	41.4	40.6
Direct	65.5	54.7	48.1	38.6	22.2
Total	105.0	88.7	84.6	80.0	62.8
Sales on Behalf of Other Parties (Brokered):					
Direct	82.6	79.8	74.8	70.5	43.9
Total Proprietary and Brokered	187.6	168.5	159.4	150.5	106.7
Direct Sales (included in the above):					
Oil sands	20.7	21.4	23.4	22.1	21.9
Sarnia refinery	23.1	17.7	17.8	19.3	6.5
Other domestic	73.0	58.2	56.2	55.5	36.0
U.S. sales	31.3	37.2	25.5	12.2	1.7
Total Direct Sales	148.1	134.5	122.9	109.1	66.1

(1) For metric equivalent data see "Supplementary Tables — Table 6".

During 1991 Suncor marketed 187.6 million cubic feet (5.3 million cubic metres) per day of which Suncor's proprietary sales accounted for 56%. The remainder was supplied by purchasing natural gas from other companies. As Suncor's own production increases, the amount of gas sales on behalf of others could be reduced.

Capital and Exploration Expenditures

The following table summarizes costs incurred, including exploration expenditures, in Resources Group for the years indicated.

	Year ended December 31				
	1991	1990	1989	1988	1987
	($ millions)				
Exploration					
Land	11	12	5	16	10
Other	23	20	16	30	28
Acquisitions	50	25	—	—	9
Development	30	38	30	28	29
Burnt Lake	3	1	7	20	—
Other	1	1	—	1	1
	$118	$ 97	$ 58	$ 95	$ 77

Environmental Compliance

Resources Group has all licences required to operate including clean water licences and clean air licences. Resources Group anticipates that all necessary licences will either be renewed or extended upon expiry.

See "Government Regulation — Environmental Regulation".

SUNOCO GROUP

Suncor conducts its refining and marketing of petroleum products and petrochemicals through its principal subsidiary, Sunoco Inc., and its subsidiaries (the operations collectively referred to as "Sunoco Group"). Sunoco Inc. is incorporated under the laws of Ontario and is wholly owned by Suncor.

During the recent period of low industry returns and declining demand, Sunoco Group has been able during the last five years to increase the proportion of its sales of gasoline and other higher margin refined products in its product mix. This increase has been in part due to the flexibility of its Sarnia refinery configuration, its ability to process synthetic crude oil and its management focus on becoming a niche regional marketer.

The following table sets forth earnings, cash provided from operating activities and capital expenditures of Sunoco Group for the years indicated.

	Year ended December 31				
	1991	1990	1989	1988	1987
			($ millions)		
Earnings	28	51	41	24	33
Cash provided from operating activities	137	22	72	85	87
Capital expenditures	38	51	42	51	34

During the last decade, the demand for refined petroleum products has declined significantly in response to private and public sector initiatives at oil conservation, more fuel efficient vehicles, taxation policies, lower alternate energy prices, economic conditions and environmental concern over the burning of fossil fuels. Sunoco Group sells refined products on both a wholesale and retail basis primarily in Ontario and Quebec, where demand for all such products declined by 15% and 31%, respectively, in the period 1980 to 1990. In 1991, demand declined again as a result of the recession. As a result of these demand declines, the industry has refining and marketing overcapacity which has resulted in low and volatile margins. However, in the period 1980 to 1990, demand for the transportation fuels segment of the refined product market, where Sunoco Group's business is focused declined only 9% in Quebec and increased by 1% in Ontario.

Recognizing these trends, between 1982 and 1984 Sunoco Group invested $304 million in a hydrocracker to improve its Sarnia refinery in order to upgrade its product slate (especially transportation fuels and petrochemicals) and to permit the use of significant amounts of synthetic crude. This improvement has resulted in the production of reduced levels of lower value by-products, primarily heavy fuel oil.

The following table sets forth the changes in proportions in the Sunoco's Group's product mix for the years indicated.

	Year ended December 31				
	1991	1990	1989	1988	1987
			(percentage of product mix)		
Co-products (1)	86.8	85.0	81.8	77.8	82.3
By-products (2)	13.2	15.0	18.2	22.2	17.7

(1) Co-products are products which generally sell above crude cost.

(2) By-products are products which generally sell below crude cost.

To improve efficiency, Sunoco Group has upgraded 50% of the plant to computer process control and lowered its inventory requirements substantially through feedstock arrangements, scheduling and other inventory management techniques.

During the last five years, Sunoco Group has lowered the costs of its distribution network. Substantial progress has been made in upgrading existing facilities, entering into joint ventures with other petroleum companies and closing obsolete high cost terminals. Sunoco Group has also discontinued non-core, low return businesses and focused attention on its core markets.

Sunoco Group is continuing a long-term program to reduce, upgrade and enhance its service station network. Over the next few years, Sunoco Group expects to reduce substantially the number of station sites while concentrating on expanding its high volume core network and its ancillary revenue and merchandising income. To secure gasoline volumes, Sunoco Group has entered into long-term management contracts to supply a number of independent chains and in 1991, entered into a joint venture agreement with United Co-operatives of Ontario ("UCO") which has a significant presence in rural Ontario. The agreement includes a long-term supply arrangement that would have represented 12% of Sunoco Group's 1991 total sales. Furthermore, it is continuing to simplify its operation and business practices, adjusting its consumer products and services and lowering its overhead costs.

Since 1985, Sunoco Group's total volume of refined products sold has increased by 24% while the number of Sunoco Inc.'s permanent employees has declined by 32%, resulting in an 83% increase in sales volume per employee.

Recent public announcements by some downstream competitors indicate that they have plans to address the overcapacity in the Canadian downstream business by closing a number of refineries, bulk plants and service stations over the next few years.

Refining

Located in Sarnia, the Sunoco Group refinery has a complex and efficient configuration. Economic refining capacity is approximately 70,000 barrels (11,100 m^3) of crude oil per day. The refinery has cracking capacity of 40,200 barrels (6,400 m^3) per day arising from a catalytic cracker and a hydrocracker. The hydrocracker, which is capable of processing approximately 24,000 barrels (3,800 m^3) per day, adds flexibility by producing premium distillate and naphthas. An alkylation unit, capable of processing 5,500 barrels (875 m^3) per day, complements a petrochemical plant for flexibility in gasoline, octane and chemical production. The performance of the refinery has been enhanced through the addition of computer process control. During 1991, the refinery had its highest level of capacity utilization in the last five years.

The refinery has considerably greater flexibility to vary the gasoline/distillate ratio than other Ontario and Quebec refineries. In addition, the refinery manufactures high value petrochemicals, a capability possessed by only a few Ontario and Quebec refiners. The refinery has expanded its capacity to manufacture jet fuel. The refinery has high octane production capability, which allows Sunoco Group's focus on higher margin premium gasolines.

Average daily crude input in 1991 was 64,000 barrels (10,200 m^3) per day compared with 1990 average input of 59,100 barrels (9,400 m^3) per day. The average utilization rate of the refinery, based upon crude unit processing capacity and input to crude units was 91% in 1991 compared to 84% in 1990. The refinery utilization rate for cracking was 92% in 1991 compared to 90% in 1990. Lower crude utilization in 1990 was partly due to a planned maintenance turnaround.

Approximately 40% of the cracking capacity at the refinery is attributable to the catalytic cracker, an older technology. Sunoco Group believes that it is capable of operating the unit throughout the 1990's, but given its age and potential environmental issues various alternatives are being explored. Such alternatives include replacement, assessing joint venture opportunities with other manufacturers, establishing alternate feedstock arrangements or shutting down the unit. Other than an estimated $17 million in environmental upgrades for this unit which may be necessary over the next few years if environmental legislation becomes more stringent, it is not anticipated that significant expenditures will be required until late in this decade.

Sunoco Group's refining operation uses both synthetic and conventional crude oil. In 1991, 68% of the crude oil refined at the Sarnia refinery was synthetic crude oil, compared with 58% in 1990, the remainder being conventional crude oil. The value of synthetic crude oil to Sunoco Group has been further enhanced through small expenditures to debottleneck facilities thereby increasing production of jet fuel and minimizing lower value products. Of the synthetic crude, approximately 62% in 1991 was from Suncor's oil sands plant production compared to 68% in 1990, with the balance purchased from others under month-to-month contracts. Conventional crude oil refined by Sunoco Group comes mainly from the production of Suncor and others in western Canada, supplemented from time to time with crude oil from the United States which is purchased or obtained in exchange for Canadian crude. Crude oil from other countries can also be delivered to Sarnia via pipeline from the United States Gulf Coast providing additional flexibility and security of supply. The market for crude oil generally is conducted on a spot basis or under contracts terminable by short notice.

The Interprovincial Pipeline from Sarnia to Montreal was shut down in 1991. A group of Ontario refiners has proposed reversing the flow in the pipeline between Montreal and Sarnia to allow an alternate means of transporting foreign sourced crude oil into Ontario. The National Energy Board is currently conducting a hearing to consider issues surrounding this matter. If this reversal were to occur, it may be less economic to transport western Canadian crude oil to the Sarnia refinery and may have an adverse impact on Suncor. Management believes, along with the majority of western Canadian crude oil producers, that there is sufficient western Canadian crude oil to meet demand requirements for the foreseeable future and that the reversal at this point is premature.

Suncor's gross crude oil production as a percentage of crude oil refined for Sunoco Group's account equalled 112% for 1991, compared with 108% for 1990.

The refinery produces transportation fuels, heating oils, heavy fuel oils, petrochemicals and liquified petroleum gases. Production of transportation fuels is optimized through an exchange agreement with a neighbouring petrochemical refinery in which feedstocks more suitable for gasoline blending are taken by Sunoco Group in exchange for feedstocks more suitable for petrochemical cracking. Sunoco Group's petrochemical facilities, with a design capacity of 10,000 barrels (1,600 m^3) per day, produce benzene, toluene and mixed xylenes and recover orthoxylene from mixed xylenes.

Sunoco Group uses reciprocal product exchanges with other refiners to minimize transportation costs, balance product availability in particular locations, and optimize refinery utilization. The largest exchange is with another regional refinery which receives products in Ontario from Sunoco Group and which supplies a similar volume of products to Sunoco Group in Quebec. This arrangement expires in 1993 and management expects that it can be renewed or replaced on acceptable terms. On occasion, Sunoco Group purchases refined products to supplement its own refinery production.

Marketing

Sunoco Group markets transportation fuels (including gasoline, diesel, jet fuel and propane), heating oils, liquified petroleum gases, residual fuel oil and asphalt feedstock under the Sunoco and various other brands to retail, industrial, commercial and wholesale customers and refiners, primarily in Ontario and Quebec. In addition, petrochemicals are marketed in North America and Europe.

Sunoco Group has increased its gasoline sales volume by 18% since 1987 and increased its other transportation fuels volume (including jet fuel) by 62%, despite limited demand growth in the overall transportation fuels market. In addition, Sunoco Group's transportation fuels volume, which generally has higher margins than other refined products, has increased from 63% of its total refined product volumes in 1987 to 72% in 1991. Domestic jet fuel sales volumes have increased by 57% since 1990 as a result of small debottlenecking expenditures and logistical improvements, the result being larger market penetration in a higher margin segment. This increase in emphasis on transportation fuels has contributed to Sunoco Group's earnings over the period.

Sunoco Group is a niche marketer which offers the consumer a unique choice of products. In 1986, Sunoco Group introduced the first super premium unleaded gasoline into the Ontario and Quebec markets, SUNOCO GOLD™. In 1991, this product was reformulated and renamed Sunoco Ultra Clean 94. Through Sunoco Ultra Clean 94, Sunoco Group believes it has greater penetration of the high margin high octane gasoline market than its competitors. Sunoco Group uses a blend pump which permits multiple grades of unleaded gasoline to be mixed from two grades in underground storage, resulting in a savings in tankage costs, reduced inventory levels and wider consumer choice.

Sunoco Group currently operates 51 car washes at its higher volume sites. Sunoco Group was the first in Canada to introduce a new system of brushless car washes utilizing high pressure water and detergents, marketed under the AQUASHINE™ and TOUCHFREE™ brands. Sunoco Group plans to upgrade its retail product and services by improving its merchandising at selected sites, adding convenience stores and mini-marts.

In December 1991, Sunoco Group entered into a joint venture effective September 27, 1991 with UCO to form a 50/50 joint venture company called UCO Petroleum Inc. ("UPI") to market petroleum and propane products in rural Ontario. The agreement includes a long-term supply arrangement under which Sunoco Group will supply UPI with its refined product needs. UPI is a leading marketer in areas geographically adjacent to Sunoco's core markets. The major markets of UPI are the farming community in rural Ontario and co-operatives which are members of UCO, as well as a network of 38 gas bars. UPI provides Sunoco Group access to a new and complementary market.

Sunoco Group also markets toluene, mixed xylenes and orthoxylene under the Sunchem name in Canada and Europe and the Chemsun name in the United States. Sunoco Group expects to enter into a petrochemical marketing and distribution joint venture in the first quarter of 1992 with a subsidiary of Sun to more efficiently serve the customers of both participants. This arrangement covers chemicals produced at Sunoco's Sarnia and the Sun subsidiary's Toledo refineries. These petrochemicals are used in manufacturing plastics, rubber and synthetic fibres, as industrial and agricultural solvents and as gasoline octane enhancers. All Sunoco Group's benzene production is sold directly by pipeline to other petrochemical manufacturers in Sarnia. Sunoco Group also sells liquified petroleum gases to various industrial users and to resellers.

Sunoco Group sells transportation fuels and other products through a network of approximately 725 retail outlets, which compares to approximately 775 outlets in December 1990. Of this total, approximately 543 retail outlets bear the Sunoco brand and are owned or leased by Sunoco Group or its dealers and 182 bear other private brands. Sunoco Group's primary market is southern Ontario and major urban markets in Quebec. Sunoco Group continues to upgrade existing sites, selectively add new, higher volume retail gasoline locations and close low volume retail gasoline locations as part of a strategy to increase average site throughput of its retail network.

During 1991, Sunoco Group sold its chemicals shipping business for proceeds of $17 million. In 1990, Sunoco Group divested its lubricants and specialty products business to a subsidiary of Sun for proceeds of $6 million. In both cases Sunoco Group is entitled to future residual royalties. Neither business was seen as a core component of Sunoco Group's strategy and neither business was material to Sunoco's earnings.

The following table sets forth the average daily volumes of refined products sold by Sunoco Group for the years indicated.

	Year ended December 31(1)				
	1991	1990	1989	1988	1987
	(thousands of barrels per day)				
Gasolines	43.5	41.3	38.2	38.5	37.0
Other transportation fuels (2)	14.4	12.7	11.8	8.7	8.9
Petrochemicals	6.6	6.3	6.7	7.0	7.1
Heating oils	5.6	6.5	7.4	4.9	7.5
Heavy fuel oils	3.7	4.3	4.0	3.9	4.1
Other (3)	7.0	7.5	10.3	13.0	8.9
Total	80.8	78.6	78.4	76.0	73.5

	Year ended December 31(1)				
	1991	1990	1989	1988	1987
	(thousands of m^3 per day)				
Gasolines	6.9	6.6	6.1	6.1	5.9
Other transportation fuels (2)	2.3	2.0	1.9	1.4	1.4
Petrochemicals	1.1	1.0	1.1	1.1	1.1
Heating oils	0.9	1.0	1.2	0.8	1.2
Heavy fuel oils	0.6	0.7	0.6	0.6	0.6
Other (3)	1.0	1.2	1.6	2.1	1.4
Total	12.8	12.5	12.5	12.1	11.6

(1) Amounts previously reported have been reclassified.
(2) Includes diesel fuel, propane for vehicle use and jet fuel.
(3) Includes lubricants, refinery feedstocks and liquified petroleum gases.

In 1991 and 1990, sales to third parties of gasolines and other transportation fuels represented 68 percent and 65 percent respectively of Suncor's consolidated sales and other operating revenues.

Transportation and Distribution

Sunoco Group employs a variety of transportation modes to deliver products by pipeline, water, rail and road. It owns and operates petroleum transportation, terminal and dock facilities in support of its refining and marketing activities. Such assets include storage facilities and bulk distribution plants in Ontario and Quebec and a 55% interest in a refined products pipeline between Sarnia and Toronto.

Sunoco Group's major mode of transportation for gasolines, diesel, jet fuel and heating oils from the Sarnia refinery to its core markets in Ontario is Sun-Canadian pipeline. The pipeline serves Sunoco Group's terminals in

London, Hamilton and Toronto, and has a capacity of 116,000 barrels (18,500 m^3) per day of which 74% was utilized in 1991. The line was originally built in 1953 and expanded in 1974. Ownership of the pipeline company is divided between Suncor with a 55% interest and another refiner with a 45% interest. The pipeline operates as a private facility for its owners and provides a low cost method of distribution.

Sunoco Group also has direct pipeline access to petroleum markets in the Great Lakes region of the United States by way of connection to a Sun subsidiary's pipeline system at Sarnia. This link, which allows for the efficient import and export of transportation fuels, heating oil, chemicals, liquified petroleum gases and intermediate feedstocks, allows Sunoco to better achieve high refinery utilization, and to quickly capitalize on purchase and sales opportunities primarily in the Michigan and Ohio markets of the United States.

During the last few years, Sunoco Group has rationalized and modernized its distribution system. In 1990, Sunoco Group signed a joint venture agreement with another major oil company to build and operate a $25 million storage and distribution terminal in North York, Ontario. The new automated terminal, which is now operational, will improve the efficiency of Sunoco Group's distribution system in the Metropolitan Toronto market.

The impact of Sunoco Group's efforts to upgrade and automate its key distribution facilities and to close and decommission less economically attractive facilities has resulted in an improvement in the average throughput and unit costs of its facilities. In 1988, average throughput at Sunoco Group terminals was 475 thousand cubic metres per year which increased to 575 thousand cubic metres per year in 1991. The cost of the product movement within Ontario and Quebec, including marine and pipeline freight, terminalling costs, and net throughput and exchange agreement costs, has declined from $5.72 per cubic metre in 1990 to $5.28 per cubic metre in 1991. At the same time, by the negotiation of exchange and throughput arrangements with other refiners and marketers, Sunoco Group has been able to achieve facility efficiencies while retaining long term access to terminal facilities in all its major markets at a level sufficient for its current and foreseeable needs.

Capital Expenditures

The following table sets forth Sunoco Group's capital expenditures in respect of refining and marketing operations for the years indicated.

	Year ended December 31				
	1991	1990	1989	1988	1987
			($ millions)		
Refining	20	22	15	12	8
Marketing	18	29	27	39	26
Total	38	51	42	51	34

Environmental Compliance

Sunoco Group has all licences required to operate its refinery and other business assets, including land, water and air licences. Sunoco Group expects that all necessary licences will be renewed or extended on expiry. While environmental standards are quickly evolving, Sunoco Group's refinery is currently in compliance in all material respects with existing regulations as a result of investments and management's actions. At service stations in Ontario, environmental risks have been reduced by the recent completion of a mandated tank replacement and upgrade program. In Quebec, Sunoco Group has begun a similar program.

Since 1987, Sunoco Group has closed approximately 65 gasoline retail sites, seven regional bulk plants, a lubricants plant in Toronto, the South Toronto terminal and the Sarnia terminal. All of these facilities have been remediated or management believes adequate provision has been made to comply with current legislation requirements for decommissioning.

As Sunoco Group pursues its plan to improve the efficiency of its marketing and distribution network, it is anticipated that other terminals, plants and retail sites may close. It is possible that further remediation will be required but the cost and timing of such remediation cannot be reasonably estimated until environmental assessments have been completed and the means of remediation determined. Remediation costs, which will be incurred over an extended period of time, may be substantial.

See "Government Regulation — Environmental Regulation".

EMPLOYEES

As at December 31, 1991, Suncor had approximately 2,856 full-time employees and 607 part-time and other employees which are counted on a full-time equivalent basis, a decline of 38 full-time employees and 73 part-time employees from 1987. The following table shows the distribution among the operating groups for the past five years.

	As at December 31				
	1991	1990	1989	1988	1987
Oil Sands Group	1,812	1,733	1,646	1,615	1,510
Resources Group	247	244	235	388	438
Sunoco Inc. permanent employees	751	837	857	903	892
Corporate	46	40	42	52	54
Total	2,856	2,854	2,780	2,958	2,894
Retail service stations and other	607	750	655	709	680

In addition to the Suncor employees, independent contractors supply a range of services to the operating, maintenance and support functions.

Oil Sands Group employees are represented by a labour union. See "Oil Sands Group — Labour Relations". Approximately 200 employees at Suncor's Sarnia refinery and approximately 100 employees in Resources Group's field operations are represented by employee associations. Relations with these associations have been constructive for many years.

GOVERNMENT REGULATION

The oil and gas industry in Canada operates under federal, provincial and municipal legislation and regulations governing various aspects of its activities. Set out below is a brief summary of some of the more significant aspects of government regulation affecting Suncor.

Environmental Regulation

Environmental legislation applies to all aspects of Suncor's operations. These regulatory regimes are laws of general application which apply to Suncor in the same fashion as they apply to other companies and enterprises in the energy resources industry. They require Suncor to obtain air, water and waste management licences and impose certain standards and controls on activities relating to oil and gas exploration, development and production, and refining and distribution of petroleum products and petrochemicals, including plant design, reclamation projects, drilling activity, decommissioning of closed facilities and well control, oil spills, leaks from transportation and storage facilities and emission standards. Environmental assessments may be required before initiating new projects or undertaking significant changes to existing projects. As societal standards evolve, Suncor is committed to meeting its responsibilities to protect the environment wherever it operates. Suncor expects to make increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. These laws will likely have an effect on methods of production, distribution and manufacturing of products, as well as on the nature of those products, for example cleaner burning gasolines. Failure to comply with such laws may result in the suspension or revocation of necessary licenses and authorizations, imposition of remediation orders, civil liability for damages sustained by others as a result of such failure to comply and the imposition of fines and penalties. Environmental concern and regulations are also likely to result in lower growth rates in demand for most petroleum products.

In the western provinces, the oil and gas industry is affected by a number of Acts and regulations relating to the environment. Alberta is currently conducting a major revision of its environmental laws and regulations to update and consolidate the various acts now applicable into the Environmental Protection and Enhancement Act. This proposed Act is scheduled to be reintroduced before the Alberta legislature in the spring of 1992. While many parts of this proposed Act and the draft regulations remain under discussion at this time, it is expected that environmental standards and compliance requirements will be stricter than at present.

Ontario and Quebec also have various environmental Acts and regulations. For example, in Ontario, the Environmental Protection Act, the Ontario Water Resources Act, the Dangerous Goods Transportation Act and the Regulations enacted pursuant to these statutes apply to the refining, storage, transportation, marketing and distribution of oil, petrochemicals, petroleum and petroleum products. As well, the Gasoline Handling Act, the Energy Act and the Regulations made thereunder apply to the storage, marketing and distribution of petroleum products, fuel oil and propane. Examples of environmental legislation in Quebec which apply to the storage, transportation, marketing and distribution of oil, petroleum and petroleum products include the Environment Quality Act, the Highway Safety Code, An Act Respecting the Use of Petroleum Products and the Regulations enacted pursuant to these statutes.

The operations of Suncor must also comply with the relevant provisions of federal environmental legislation, including the Canadian Environmental Protection Act and the Fisheries Act.

Pricing, Production and Exports

Producers of oil and natural gas and petroleum and petrochemical products are permitted to negotiate sales contracts at competitive market prices directly with both domestic and export customers.

The western producing provinces have enacted statutory provisions regulating the production of crude oil and natural gas. The maximum allowable gross production of crude oil and natural gas from conventional wells in western Canada is limited by the various regulatory authorities on the basis of sound reservoir engineering, conservation practices, pipeline capacity and market demand. In Alberta, the Alberta Energy Resources Conservation Board ("AERCB") determines maximum rates of production of crude oil and natural gas from pools based on reservoir size, characteristics and production mechanisms, and generally allocates monthly aggregate demand for crude oil production among producing pools on the basis of reserves under a "Modified Market Proration Plan". Construction of facilities and operations to recover crude oil from oil sands or bitumen in Alberta also requires the approval of the AERCB and the Government of Alberta.

An export order or licence issued by the National Energy Board ("NEB") and approval by the Government of Canada are required to export natural gas from Canada and to export crude oil where the contract term exceeds one year in the case of light crude oil and two years in the case of heavy crude oil. The NEB has reduced emphasis on ensuring there is a surplus of supply of crude oil and natural gas for reasonably foreseeable Canadian requirements, for the purpose of determining whether an export order or licence should be issued. The NEB currently utilizes ex-post monitoring of the market place to ensure that Canadians are not placed at a disadvantage. The NEB developed a "Market Based Procedure" in 1987 for these approvals, which was updated in 1990 and is reviewed periodically. The NEB acts in two ways to ensure that the natural gas to be licensed for export is surplus to reasonably foreseeable Canadian requirements, firstly by conducting a complaints procedure, and secondly by monitoring Canadian energy markets on an ongoing basis. Such monitoring is intended to permit the NEB to be alert to any difficulties for Canadians in adjusting to changes in natural gas supply, demand and prices.

Land Tenure

Oil and gas rights are primarily acquired from the various provincial governments and federal government in Canada. Some mineral rights are also acquired from private interests.

Provincial Lands

Oil and natural gas located in the western provinces are owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms and on conditions set forth in provincial legislation. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Oil produced from oil sands is produced under Crown Oil Sand Leases which have an initial term of 21 years, renewable for one further term of 15 years without any production. Thereafter leases are only renewable for further 15 year terms if a plant or "other works" are in operation. The Government of Alberta is currently revising its oil sands lease tenure regulations.

Some of Suncor's rights held in Alberta, British Columbia and Saskatchewan are subject to work commitments.

Frontier Areas

Canada's frontier and offshore areas are generally subject to the jurisdiction of the Government of Canada except for Newfoundland and Nova Scotia offshore areas which are under joint federal-provincial regimes.

In frontier areas exploration rights are generally granted through an exploration licence. If a significant discovery is made, the holder of an exploration licence is entitled to a significant discovery licence, over the portion of the exploration licence area to which the discovery extends, for an indefinite period, subject to compliance with any drilling orders issued by applicable authorities. If a commercial discovery is made, the holder of an exploration licence or significant discovery licence is entitled, subject to certain Canadian ownership restrictions described below, to a production licence over that portion of the exploration licence area or significant discovery licence area over which the commercial discovery extends, granting exclusive rights to produce petroleum for an initial period of 25 years. Extensions of a production licence beyond the initial term can be obtained if the lands under the licence are still producing or are capable of production in commercial quantities.

The issue and transfer of a production licence is subject to certain Canadian ownership requirements. In the case of discoveries before March 1982, the Minister of Energy, Mines and Resources, Canada, must be satisfied that each holder of a share in a production licence meets the Canadian ownership requirements of the Canada Oil and Gas Land Regulations. In the case of discoveries after March 1982, the initial holders of a production licence must, subject to the discretion of the Minister of Energy, Mines and Resources, Canada, have a collective 50% Canadian ownership rate as determined under the relevant legislation. The consent of the Minister of Energy, Mines and Resources, Canada is required for the transfer of a share in a production licence, which may be withheld on grounds relating to Canadian ownership.

Suncor's Canadian ownership rate is provisionally calculated to be in the order of 25%. Subject to the discretion of the Minister of Energy, Mines and Resources, Canada, until Sun's direct and indirect ownership falls below 50%, Suncor may become the holder of a production licence on Frontier lands only in association with other holders who, together with Suncor, have a collective Canadian ownership rate of at least 50%.

Royalties

The producing provinces, the Government of Canada and private owners impose royalties of varying rates on the production of crude oil, natural gas, natural gas liquids and sulphur from lands where they own the mineral rights. Some producing provinces also impose freehold mineral taxes on crude oil and natural gas produced from lands owned by private owners, who themselves generally have reserved fixed rate royalties on production. For purposes of royalty calculations, a system of deemed pricing is utilized in Alberta. In Manitoba, a tax is imposed on production from freehold or private oil and gas properties and daily and monthly maximum production amounts are allocated on a per well basis, depending on the field and pool in which the well is located.

The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties on conventional crude oil and natural gas owned by provincial governments are determined by regulation and may be amended from time to time. Royalties are generally calculated as a percentage of production and vary depending upon factors such as well production volumes, selling prices, method of recovery, location of production and date of discovery. Royalties payable on production of privately owned crude oil and natural gas are negotiated with the mineral owner. In 1991, Suncor's average royalty rates were 18.9% for conventional crude oil and 15.1% for natural gas produced in the western provinces. For a discussion of royalties payable on production from oil sands projects see "Oil Sands Group — Leasehold Interests and Royalties" and "Oil Sands Group — Outlook".

The Government of Canada is currently developing a comprehensive royalty regime for frontier and offshore lands under its exclusive jurisdiction; royalty regimes for Newfoundland and Nova Scotia offshore areas will be governed by the terms of the applicable joint federal-provincial arrangement.

For Frontier Lands, the Government of Canada has issued a draft of the Frontier Lands Petroleum Royalty Regulations and has announced reduced royalties in the early years of a project before it becomes profitable with increases in stages to a royalty after "payout" (to be defined by regulation) of 30% of net cash flow, subject to any negotiated changes. A 25% investment royalty credit applicable to frontier exploration well costs of up to $5 million was also proposed for new exploration wells, with the credit to be applied against royalties otherwise payable.

Canadian Income Taxes

Suncor Inc. and Sunoco Inc. and other subsidiaries each are subject to Canadian federal and provincial income taxes of general application. The 1991 general federal tax rate applicable to these entities is 38%. Various abatements, credits and deductions are available to reduce this rate. In addition, these entities are subject to provincial taxes at rates varying from approximately 7% to 17%. There is also a surtax on federal corporate income tax of 3%. The federal government introduced a large corporation tax effective July 1, 1989. The tax, at a rate of 0.2% for 1991 and subsequent years, is applied to taxable capital employed in Canada in excess of $10 million. Under the present law, the large corporations tax is not deductible for income tax purposes but may be deducted against the 3% corporate surtax. On February 21, 1992, the Canadian Minister of Finance announced that he intended to amend the law, generally effective for 1992 and subsequent taxation years, to reverse the ordering of this credit mechanism such that the 3% corporate surtax will be creditable against the large corporations tax.

Payments made to the Canadian federal and provincial governments for royalties, freehold mineral taxes, production lease rentals and exploration lease rentals in excess of $1.01 per acre ($2.50 per hectare) are not deductible for income tax purposes. To compensate partially for this non-deductibility, a special deduction equal to 25% of net production revenue, before Crown payments, is provided. For a further discussion of the effective tax rates, see note 8 to Suncor's consolidated financial statements.

Incentives

From time to time the provincial governments of Saskatchewan, Alberta and British Columbia create incentive programs which have historically included royalty rate reductions, royalty holidays and tax credits in order to encourage exploration, particularly when energy prices are low. Incentives are intended to enhance the existing cash flow of the oil and gas industry and to improve the economics of finding and developing new and more costly oil and gas reserves. The Deep Gas Royalty Holiday Program in Alberta provides for royalty holidays for wells with a producing interval below 2,500 metres for which the drilling spacing unit is wholly outside the deep gas pools in effect June 1, 1985, as defined by the AERCB.

On November 7, 1991 the Alberta government announced the Oil Industry Activity Program which is intended to increase activity for oil exploration and development in Alberta. This program provides generally for an oil royalty holiday of two years for exploration wells spudded or deepened between November 1, 1991 and March 31, 1992 and of one year for wells drilled between April 1, 1992 and March 31, 1993. For the northern and foothills regions the qualification period for the two year holiday will be extended to April 1, 1993, due to access restrictions. A $1,000,000 per well royalty cap will apply. An oil royalty holiday of one year will be available for development oil wells spudded or deepened between November 1, 1991 and March 31, 1993, to which a royalty cap not exceeding $400,000 per well will apply. Further, an oil royalty holiday of five years will be available on reactivated oil wells, with a 25,000 barrel per well production cap. Finally, certification for new oil status will be given without application to all oil wells drilled after October 31, 1991, to all oil wells reactivated under this program and to all currently inactive oil wells which are reactivated after a shut-in of one year.

In Saskatchewan, a program announced in June of 1990 modified the two year royalty/tax holiday applicable to new "special development" oil wells and incremental oil from new or expanded waterflood projects which applied to the end of 1991 in designated heavy oil areas. The holidays are being phased out. The existing oil royalty/tax holiday pertaining to deep wells, exploratory wells and development wells do not have expiry dates. In British Columbia all oil discovery wells qualify for a three year holiday.

The Government of Alberta provides a refundable royalty tax credit ("ARTC") in respect of qualifying Alberta Crown royalties. Crown royalties payable in respect of restricted resource properties, and mineral rights taxes paid in respect of freehold lands, do not qualify for ARTC. A five year price sensitive ARTC program has been in effect since January 1, 1990. Under the program the royalty tax credit of a corporation for a taxation year is the lesser of its Alberta crown royalty and its "crown royalty shelter" for the year multiplied by the "weighted average rate" determined for a corporation for its taxation year, which rate varies inversely with prevailing oil prices. The ARTC base is limited to $2.5 million of qualifying Alberta Crown royalties in a taxation year. The annual limit on ARTC must be allocated among corporations "associated" with one another in a taxation year.

Investment Canada Act

The Investment Canada Act came into force on June 30, 1985 and replaced The Foreign Investment Review Act. The Investment Canada Act requires the approval of the Government of Canada with respect to certain acquisitions of control of Canadian businesses, which may in certain circumstances include the acquisition of natural resource properties, by an entity that is not controlled by Canadians. By virtue of Sun being its majority shareholder, Suncor is considered to be an entity not controlled by Canadians. Where a new, unrelated business in Canada is established by entities not controlled by Canadians, notification only, and not Government of Canada approval, is required unless the new business is related to Canada's cultural heritage or national identity.

ITEM 4 SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following selected consolidated financial information, except for the quarterly data, for each of the years in the five year period ended December 31, 1991 is derived from Suncor's consolidated financial statements. The consolidated financial statements for each of the years in the five year period ended December 31, 1991 have been examined by Coopers & Lybrand, Chartered Accountants, whose report thereon appears in the Annual Report to Shareholders for the year ended December 31, 1991. The information set forth below should be read in conjunction with Management's Discussion and Analysis, Suncor's consolidated financial statements and related notes and other financial information included in the Annual Report to Shareholders for the year ended December 31, 1991.

	Year ended December 31 (1)				
	1991	1990	1989	1988	1987
	($ millions except per share amounts)				
Revenues (excluding federal sales tax)	1,566	1,657	1,399	1,263	1,290
Net earnings (loss)	77	124	57	(44)	43
Per common share	1.42	2.27	1.05	(0.84)	0.77
Cash provided from operating activities (2)	303	254	206	98	178
Per common share	5.57	4.67	3.79	1.80	3.27
Capital and exploration expenditures	232	179	141	214	154
Dividends per share:					
Preferred Shares, Series A	1.92	1.92	1.92	1.92	1.92
Common Shares					
Cash dividends	1.05	0.40	—	0.39	0.20
Dividends paid in common shares	—	—	0.40	—	0.19

	As at December 31 (1)				
	1991	1990	1989	1988	1987
	($ millions)				
Total assets	2,238	2,259	2,065	2,043	2,102
Long-term borrowings (3)	141	222	223	296	223
Preferred Shares, Series A	6	6	7	7	7
Common shareholders' equity	1,220	1,200	1,098	1,042	1,108

(1) As more fully described in Note 1 to Suncor's consolidated financial statements, certain figures have been restated to reflect changes in accounting policy.

(2) Before changes in operating working capital.

(3) Includes current portion.

	Three months ended							
	Dec. 31 1991	Sept. 30 1991	June 30 1991	Mar. 31 1991	Dec. 31 1990	Sept. 30 1990	June 30 1990	Mar. 31 1990
	($ millions except per share amounts) (unaudited)							
Revenues (excluding federal sales tax)	402	378	398	388	519	412	368	358
Net earnings (loss)	5	27	13	32	83	30	(10)	21
Per common share	0.10	0.49	0.25	0.58	1.51	0.56	(0.18)	0.38
Cash provided from (used in) operating activities (1)	73	65	66	99	153	65	(27)	63
Per common share	1.34	1.20	1.21	1.82	2.81	1.20	(0.50)	1.16

(1) Before changes in operating working capital.

DIVIDEND POLICY AND RECORD

Suncor's board of directors has established a policy of paying dividends on a quarterly basis. A dividend for the first quarter of 1992 has been declared of $0.26 ($1.04 per annum) per common share payable on March 18, 1992 to shareholders of record on February 28, 1992. This policy will be reviewed from time to time in light of Suncor's financial position, its financing requirements for growth, its cash flow and other factors considered relevant by Suncor's board of directors.

The following table sets forth the per share amount of dividends paid by Suncor during the last five years.

	Year ended December 31				
	1991	1990	1989	1988	1987
Preferred Shares Series A	$1.92	$1.92	$1.92	$1.92	$1.92
Common Shares					
Cash dividends	$1.05	$0.40	—	$0.39	$0.20
Dividends paid in Common Shares	—	—	$0.40	—	$0.19

ITEM 5 MANAGEMENT'S DISCUSSION AND ANALYSIS

The information required by this item is incorporated herein by reference to pages 30 to 43 in the Company's 1991 Annual Report to Shareholders.

ITEM 6 MARKET FOR THE SECURITIES OF THE ISSUER

Prior to March 18, 1992 the common shares were not listed on any stock exchange in Canada or elsewhere but were part of the over-the-counter automated trading system of the Canadian Dealing Network, a subsidiary of the Toronto Stock Exchange. On March 18, 1992 (following the completion of a public offering by Sun Company, Inc. and Ontario Energy Corporation of a portion of their direct and indirect holdings of common shares of Suncor) the common shares of Suncor were listed on each of the Toronto Stock Exchange, the Montreal Stock Exchange, The Alberta Stock Exchange and the Vancouver Stock Exchange. The public offering by Sun Company, Inc. and the Ontario Energy Corporation was effected on an instalment receipt basis. Prior to full payment therefor on or before March 18, 1993, the common shares so sold will be represented by instalment receipts. Such instalment receipts have been listed and posted on each of the foregoing stock exchanges at least until the date of payment of the final instalment; common shares have been listed on all exchanges but have only been posted for trading on The Alberta Stock Exchange. The common shares will be posted for trading on the other exchanges when a minimum number of instalment receipt holders have paid the final instalment.

ITEM 7 DIRECTORS AND OFFICERS

Directors

Suncor's Articles stipulate that there shall be not more than 15 nor fewer than 8 directors, as the board of directors may determine from time to time. It is presently determined that the board of directors shall consist of 14 directors. The term of office of each director is from the date of the meeting at which he is elected until the next annual meeting of shareholders or until a successor is elected or appointed.

Name and Municipality of Residence	Director Since (1)	Principal Occupation
Robert M. Aiken, Jr. (2) ..... Berwyn, Pennsylvania	1990	Senior Vice President and Chief Financial Officer, Sun Company, Inc.
Harry Booth, C.A. (2) .... Calgary, Alberta	1984	Retired Chairman and Chief Executive Officer, Alberta Natural Gas Company Ltd. (a company with natural gas transportation and petrochemical interests)
Max B. E. Clarkson .... Toronto, Ontario	1977	Professor Emeritus and Director, Centre for Corporate Social Performance and Ethics, Faculty of Management, University of Toronto
Bryan P. Davies (2).......... Toronto, Ontario	1991	Vice President, Business Affairs and Chief Administrative Officer at the University of Toronto
George Davies .... Toronto, Ontario	1991	Deputy Minister of the Ontario Ministry of Energy
Richard L. George .... Oakville, Ontario	1991	President and Chief Executive Officer, Suncor Inc.
Ardagh S. Kingsmill, Q.C. (2) Toronto, Ontario	1964	Partner, McCarthy Tétrault (a law firm)
David E. Knoll .... Chester Springs, Pennsylvania	1991	Group Vice President, Refining and Marketing, Sun Company, Inc.
Michael M. Koerner, C.M. ... Toronto, Ontario	1977	President, Canada Overseas Investments Ltd. (a venture capital investment management company)
Bill N. Rutherford .... Berwyn, Pennsylvania	1988	Senior Vice President, Human Resources and Administration, Sun Company, Inc.
J. A. Guy Saint-Pierre ...... Montreal, Quebec	1980	President and Chief Executive Officer, The SNC Group Inc. (a company with operations in engineering, construction and defence manufacturing)
Thomas H. Thomson......... North York, Ontario	1985	Chairman of the Board, Suncor Inc.
W. Robert Wyman (2) .... Vancouver, British Columbia	1987	Chairman and Chief Executive Officer, British Columbia Hydro and Power Authority

(1) Suncor was formed by the amalgamation of Sun Oil Company Limited and Great Canadian Oil Sands Limited on August 22, 1979. Each director has served as a director of Suncor or one of the amalgamating companies since the date shown, with the exception of Mr. Kingsmill, who was not a director of either amalgamating company for the periods October 18, 1968 to March 28, 1969 and June 23, 1971 to April 25, 1974.

(2) Member of Audit Committee.

In addition to the Audit Committee of the Board of Directors of Suncor, the Suncor Board has constituted a Board Policy and Strategic Planning Committee and a Human Resources and Compensation Committee. The Board also intends to establish an Environment, Health and Safety Committee following Suncor's Annual Meeting of Shareholders to be held in May 1992.

Except as otherwise indicated below, all of the directors have been engaged in their present principal occupations or in other executive capacities with the companies, firms or government ministries with which they currently hold positions for more than five years. Prior to February, 1992 Mr. Bryan P. Davies was Deputy Treasurer of Ontario and Deputy Minister of Economics; prior to September 1989, he was the Deputy Minister of the Ontario Ministry of Housing; prior to September 1988, he was the Deputy Minister of the Ontario Ministry of Financial Institutions and prior to April 1986, he was the Deputy Minister of the Ontario Ministry of Citizenship and Culture. Prior to August 1991 Mr. George Davies was Assistant Deputy Minister, Policy Development and Coordination Division of the Ontario Ministry of Energy and prior to June 1990 he was the Executive Coordinator of the Policy Development Section of the Ontario Ministry of Energy and prior to October 1988 he was Senior Advisor, Economic Policy and Programs in the Federal Provincial Relations Office for the Government of Canada. Prior to February 1991, Mr. George was the Managing Director of Sun International Exploration and Production Company Limited and Managing Director of Sun Oil Britain Limited; prior to November 1988 he was Vice President of Sun International Exploration and Production Company and prior to July 1987 he was District Manager of North Sea Sun Oil Company Ltd. Mr. Kingsmill was a partner in the law firm of Tilley, Carson & Findlay prior to April 1988. Mr. Knoll was Vice President, Sunoco Marketing, Sun Refining and Marketing Company prior to May 1988, was Vice President Fuels, Sun Refining and Marketing Company prior to November 1988 and was President, Sun Refining and Marketing Company prior to September 1991. Mr. Saint-Pierre was President and Chief Executive Officer of Ogilvie Mills Ltd. and Senior Vice President of John Labatt Limited prior to January 1989. Mr. Wyman was Chairman of Pemberton Securities Inc. prior to June 1989 and was Vice-Chairman of RBC Dominion Securities, Inc. prior to March 1991.

Officers

Name and Municipality of Residence	Position	Officer Since (1)
Thomas H. Thomson North York, Ontario	Chairman of the Board	1985
Richard L. George Oakville, Ontario	President and Chief Executive Officer	1991
Douglas G. MacKenzie Oakville, Ontario	Executive Vice President, Sunoco Group	1986
Edythe A. Parkinson Fort McMurray, Alberta	Executive Vice President, Oil Sands Group	1991
Barry D. Stewart Calgary, Alberta	Executive Vice President, Resources Group	1991
Michael A. Supple Calgary, Alberta	Executive Vice President	1983
Michael W. O'Brien Toronto, Ontario	Senior Vice President and Chief Financial Officer	1986
Peter T. Spelliscy Etobicoke, Ontario	Senior Vice President, Human Resources and Administration	1984
Donald R. Brown, Q.C. Toronto, Ontario	Vice President, General Counsel and Secretary	1988
Arnold L. Godin Fort McMurray, Alberta	Vice President, Utilities, Upgrading and CMD, Oil Sands Group	1986
Rudy A. Krueger Fort McMurray, Alberta	Vice President, Business Services, Oil Sands Group	1990
Bernard A. Lang Fort McMurray, Alberta	Vice President, Technical and Business Development, Oil Sands Group	1986
Gregory B. Lindsay Fort McMurray, Alberta	Vice President, Mine and Extraction, Oil Sands Group	1990

Name and Municipality of Residence	Position	Officer Since (1)
DAVID W. BYLER .... Calgary, Alberta	Vice President, Finance and Human Resources, Resources Group	1991
ROGER W. SMITH .... Calgary, Alberta	Vice President, Exploration, Resources Group	1990
W. ROSS WEAVER .... Calgary, Alberta	Vice President, Marketing, Resources Group	1990
HENDRIK H. WIND .... Calgary, Alberta	Vice President, Production, Resources Group	1989
ANTHONY A. L. WRIGHT ...... Toronto, Ontario	Treasurer and Assistant Secretary	1969
DAVID R. MAUGHAN .... North York, Ontario	Assistant Treasurer	1988

(1) Includes service as an officer of Sun Oil Company Limited or Great Canadian Oil Sands Limited, which amalgamated to form Suncor Inc.

The principal occupation of each officer is the office held with Suncor. Each such officer has been engaged in his or her present principal occupation or in other executive or employee capacities with Suncor or its affiliates for the past five years, other than as follows: Mr. George was District Manager of North Sea Oil Company Ltd. prior to July 1987, was Vice President of Sun International Exploration and Production Company prior to November 1988 and Managing Director of Sun International Exploration and Production Company Limited and Managing Director of Sun Oil Britain Limited (formerly North Sea Oil Company Ltd.) prior to February 1991; Mr. Brown was Vice-President and General Counsel of Traders Group Limited prior to February 1988; Mr. Krueger was Manager Human Resources Central Region (Ontario) of Petro-Canada Inc. prior to December 1987; Ms. Parkinson was Senior Director, Planning of Petro-Canada Products prior to September 1987, was Manager, Edmonton Refinery of Petro-Canada Inc. prior to September 1988, was General Manager, Refining — Western Region of Petro-Canada Inc. prior to January 1990 and was Vice President, Supply and Services of Ontario Hydro prior to September 1991; Mr. Smith was Manager, Special Projects (Business Development) of Canadian Hunter Exploration Ltd. prior to July 1989 and a Consulting Geologist prior to July 1990; Mr. Stewart was Senior Vice President, Production, Resources Division of Petro-Canada Inc. prior to June 1986, was Senior Vice President, Western Region, Products Division of Petro-Canada Inc. prior to January 1989, and was President, Products Division of Petro-Canada Inc. prior to September 1990. Prior to August, 1988, Mr. Weaver was Project Manager Ethane Marketing, Dome Petroleum Ltd.

As of March 19, 1992, the directors and senior officers of Suncor, as a group, beneficially owned, directly or indirectly, none of the issued Preferred Shares Series A and less than 1% of the issued common shares of Suncor.

ITEM 8 ADDITIONAL INFORMATION

Additional information, including remuneration of directors and executive officers, indebtedness of directors and officers, principal holders of Suncor's securities and interests of insiders in material transactions is contained in Suncor's Management Proxy Circular dated March 19, 1992 for the annual meeting of shareholders to be held on May 1, 1992. Additional financial information is provided on pages 45 to 59 and in the Auditors' Report on page 44 of Suncor's Annual Report to Shareholders for the year ended December 31, 1991. The foregoing information is incorporated herein by reference.

Copies of these documents may be obtained upon request from the Secretary, Suncor Inc., 36 York Mills Road, North York, Ontario, M2P 2C5.

SUPPLEMENTARY TABLES

SUPPLEMENTARY TABLES

Supplementary Table 1

Conventional Oil

The following table shows estimates of Suncor's proved crude oil reserves before royalties as prepared by CGA and Suncor's average daily production of crude oil before royalties represented by the major conventional oil fields identified in the table. The fields specified in the table represent over 65% of Suncor's proved reserves and gross production.

Fields	Proved Reserves Before Royalties at December 31, 1991		1991 Average Daily Production Before Royalties	
	(millions of m^3)	(%)	(m^3 per day)	(%)
Oungre	0.8	17	144	9
Medicine River	0.7	14	223	14
Pembina	0.4	8	82	5
Swan Hills	0.3	7	68	4
Youngstown	0.3	7	230	15
Steelman	0.3	6	66	4
Provost	0.1	3	114	8
Blueberry	0.1	3	27	2
Boundary Lake	0.1	3	35	2
Mitsue	0.1	3	48	3
Gleneath	0.1	2	21	1
Other (1)	1.4	27	533	33
	4.7	100	1,591	100

(1) Includes fields in which Suncor holds overriding royalty interests.

(2) The reserves and production in this table do not include natural gas liquids.

Natural Gas

The following table shows estimates of Suncor's proved natural gas reserves before royalties as prepared by CGA and Suncor's average daily production before royalties represented by the major natural gas fields identified in the table. The fields specified in the table represent 50% of Suncor's proved reserves and gross production.

Fields	Proved Reserves Before Royalties at December 31, 1991		1991 Average Daily Production Before Royalties	
	(billions of m^3)	(%)	(thousands of m^3 per day)	(%)
Rosevear	2.8	20	580	20
Glacier (1)	1.5	11	—	—
Stolberg	1.2	9	90	3
Pine Creek	1.0	7	130	4
Adsett (1)	0.7	5	—	—
Bonanza	0.7	5	51	2
Blueberry	0.7	5	39	1
East Mel	0.4	3	135	4
Pocketknife	0.3	2	166	6
Progress	0.3	2	169	6
Calling Lake	0.3	2	136	4
Other (2)	3.9	29	1,463	50
	13.8	100	2,959	100

(1) Scheduled to commence production in 1992.

(2) Includes fields in which Suncor holds overriding royalty interests.

Supplementary Table 2

Land Holdings

The following table sets forth the undeveloped and developed land in which Resources Group held petroleum and natural gas interests at December 31, 1991 and 1990, except as indicated in notes (3) and (4), below. Undeveloped lands are lands on which no producing well or well capable of production has been drilled and developed lands are lands on which such a well has been drilled.

	Licences, Reservations, Permits and Exploration Agreements(1)				Leases(1)			
	Gross Hectares(2)		Net Hectares(2)		Gross Hectares(2)		Net Hectares(2)	
	1991	1990	1991	1990	1991	1990	1991	1990
	(thousands)				(thousands)			
Undeveloped Lands								
Western Provinces(3)								
British Columbia	49.9	29.3	34.4	19.3	62.4	55.6	37.3	31.6
Alberta(4)	161.2	114.8	83.4	65.3	172.5	116.4	86.3	66.8
Saskatchewan	24.5	24.5	24.5	24.4	6.3	9.5	2.9	4.9
Manitoba	—	—	—	—	—	1.0	—	1.0
Total	235.6	168.6	142.3	109.0	241.2	182.5	126.5	104.3
Frontier (Canada Lands)								
Northwest Territories	19.2	19.2	14.4	14.4	—	—	—	—
MacKenzie Delta	—	—	—	—	2.7	2.7	1.2	1.2
Beaufort Sea	97.9	273.5	5.1	14.1	14.0	14.0	1.5	1.5
Arctic Islands	—	—	—	—	158.6	158.6	22.5	22.6
Offshore Labrador	—	—	—	—	25.2	25.2	2.5	2.5
Total	117.1	292.7	19.5	28.5	200.5	200.5	27.7	27.8
Developed Lands								
Western Provinces(3)								
British Columbia	1.0	0.1	0.8	0.1	52.4	51.6	18.6	18.2
Alberta(4)	4.1	3.5	1.5	1.3	324.6	271.9	140.6	150.6
Saskatchewan	—	—	—	—	10.9	12.6	8.7	10.7
Manitoba	—	—	—	—	1.0	0.6	0.6	0.6
Total	5.1	3.6	2.3	1.4	388.9	336.7	168.5	180.1
Frontier (Canada Lands)								
Northwest Territories	—	—	—	—	5.7	5.7	5.7	5.7
Mackenzie Delta	—	—	—	—	2.9	2.9	1.1	1.1
Total	—	—	—	—	8.6	8.6	6.8	6.8

(1) No deduction has been made from Crown licences, reservations, permits or exploration agreements to reflect that only a portion of these areas may be converted to lease or production licence. Crown licences, reservations and permits are acquired from the provincial governments through competitive bidding and exploration agreements are acquired from the federal government by undertaking work commitments. These confer upon the holder exploration rights and the right to lease or apply for a production licence for the crude oil and natural gas rights under portions of the lands covered. The extent of such rights differs in each jurisdiction and between various areas in a single jurisdiction. The holder is generally required to make cash payments or undertake specified work in order to retain such rights. Leases in general confer upon the lessee the right to explore for and remove crude oil and natural gas from the property with the lessee paying all the development and operating costs and being entitled to the production, subject to rental, tax and royalty.

(2) "Gross hectares" means all hectares in which Suncor has an interest. "Net hectares" means gross hectares after deducting interests of others.

(3) Includes 112,098 gross developed hectares and 7,584 gross undeveloped hectares (1990 — 90,781 and 3,434) in western Canada in which Suncor held overriding royalty interests at the end of the years indicated and from which it received revenues of about $3.1 million in 1991 and $3.7 million in 1990.

(4) Not included in the table are the oil sands (including non-conventional heavy oil) leases comprising 108,196 gross (59,974 net) undeveloped hectares and 9,560 gross (3,099 net) developed hectares at the end of both years.

Supplementary Table 3

Reserves

CGA has reported on Suncor's reserves of crude oil, natural gas and natural gas liquids. The following table sets forth CGA's determination of Suncor's estimated recoverable reserves, based on constant year end prices and costs with no escalation into the future, as of the dates indicated.

	Gross		Net	
	Crude oil and natural gas liquids	Natural gas	Crude oil and natural gas liquids	Natural gas
	(millions of m^3)	(billions of m^3)	(millions of m^3)	(billions of m^3)
Proved:				
December 31, 1989	6.7	10.2	5.7	8.5
Revisions	0.2	0.2	0.1	0.2
Acquisitions	0.2	1.4	0.1	1.2
Other additions	0.3	0.6	0.2	0.5
Production	(0.7)	(0.9)	(0.5)	(0.8)
Sales	—	(0.1)	—	(0.1)
December 31, 1990	6.7	11.4	5.6	9.5
Revisions	(0.2)	(0.2)	(0.1)	(0.3)
Acquisitions	0.3	2.9	0.2	2.4
Other additions	0.4	0.9	0.4	0.7
Production	(0.7)	(1.1)	(0.5)	(0.8)
Sales	(0.4)	(0.1)	(0.4)	—
December 31, 1991	6.1	13.8	5.2	11.5
Proved Producing:				
December 31, 1989	6.0	6.3	5.1	5.2
Revisions	0.2	0.6	—	0.5
Acquisitions	0.1	0.8	0.1	0.7
Other additions	0.2	0.1	0.1	0.1
Production	(0.7)	(0.9)	(0.5)	(0.8)
Sales	—	(0.1)	—	(0.1)
December 31, 1990	5.8	6.8	4.8	5.6
Revisions	—	0.7	—	0.4
Acquisitions	0.1	2.1	0.1	1.8
Other additions	0.4	0.3	0.3	0.2
Production	(0.7)	(1.1)	(0.5)	(0.8)
Sales	(0.4)	(0.1)	(0.3)	—
December 31, 1991	5.2	8.7	4.4	7.2
Probable additional:				
December 31, 1990	2.6	6.4	2.2	5.2
December 31, 1991	2.6	6.8	2.1	5.6

Notes:

(1) Proved reserves are those reserves estimated as recoverable, under current technology and existing economic conditions, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.

Proved producing reserves are those proved reserves that are actually on production or, if not producing, that could be recovered from existing wells or facilities and where the reason for the current non-producing status is the choice of the owner rather than the lack of markets or some other reason. An illustration of such a situation is where a well or zone is capable but is shut-in because its deliverability is not required to meet contract commitments.

Probable additional reserves are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

(2) Gross reserves represent the aggregate of Suncor's working interest in reserves including the royalty interest of governments and others in such reserves and Suncor's royalty interest in reserves of others. Net reserves are gross reserves less the royalty interest share of others including governments. Royalties can vary depending upon selling prices, production volumes, timing of initial production and changes in legislation. Net reserves have been calculated, following generally accepted guidelines, on the basis of prices and the royalty structure in effect at year end and anticipated production rates. Such estimates by their very nature are inexact and subject to constant revisions.

(3) No amounts have been included for non-conventional reserves.

Supplementary Table 4

Production

The following table sets out Suncor's gross and net production during the years indicated. Gross production is that attributable to Suncor's share of production before deduction of applicable royalties and interests owned by others. Net production is gross production less such royalties and other interests.

	Years ended December 31									
	1991		1990		1989		1988		1987	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Crude Oil (thousands of m^3)										
Alberta	394	327	424	350	427	357	476	398	472	394
Saskatchewan	130	97	136	98	136	97	200	150	234	170
British Columbia	46	40	44	35	38	31	45	37	43	34
Manitoba	11	8	11	9	12	9	14	10	15	11
Total	581	472	615	492	613	494	735	595	764	609
Natural Gas Liquids (thousands of m^3)										
Alberta	75	56	64	47	57	43	64	49	41	30
British Columbia	5	4	4	3	3	2	3	3	4	3
Saskatchewan	—	—	—	—	—	—	—	—	1	1
Total	80	60	68	50	60	45	67	52	46	34
Total Liquids	661	532	683	542	673	539	802	647	810	643
Natural Gas (millions of m^3)										
Alberta	906	700	805	628	825	644	785	628	596	481
British Columbia	168	152	99	88	38	33	31	27	39	34
Saskatchewan	6	5	8	7	6	5	9	7	11	9
Total	1,080	857	912	723	869	682	825	662	646	524

Supplementary Table 5

Sales Prices and Lifting Costs

The following table shows sales prices and lifting costs in connection with Suncor's conventional crude oil and natural gas operations for the years indicated.

	Year ended December 31				
	1991	1990	1989	1988	1987
Average sales price					
Crude oil ($ per barrel)	20.59	25.03	19.26	15.95	21.33
Crude oil and natural gas liquids ($ per barrel)	19.86	24.48	18.60	15.42	20.83
Natural gas ($ per thousand cubic feet)	1.31	1.43	1.28	1.41	1.48
Average lifting costs of oil and gas ($ per equivalent barrels of gross production) (1)(2)	2.75	2.75	2.73	3.22	3.29
Average sales price					
Crude oil ($ per m^3)	130	157	121	100	134
Crude oil and natural gas liquids ($ per m^3)	125	154	117	97	131
Natural gas ($ per thousand m^3)	46	51	45	50	52
Average lifting costs of oil and gas ($ per equivalent m^3 of gross production) (1)(2)	17	17	17	20	21

(1) Lifting costs include all expenses related to the operation and maintenance of producing or producible wells, gas plants and gathering systems. Such costs do not include royalties, depreciation and depletion, selling, general and administrative expenses and income taxes.

(2) Computed under the relative energy content method whereby a volume of natural gas is equated to an equivalent volume of crude oil at 6:1.

Supplementary Table 6

Gas Marketing Operations

The following table summarizes the volumes of gas marketed directly or indirectly by Suncor for the years indicated.

	Year ended December 31				
	1991	1990	1989	1988	1987
	(thousands of m^3 per day)				
Sales for Suncor's Own Account (Proprietary):					
System	1.1	1.0	1.0	1.2	1.1
Direct	1.9	1.5	1.4	1.1	0.6
Total	3.0	2.5	2.4	2.3	1.7
Sales on Behalf of Other Parties (Brokered):					
Direct	2.3	2.2	2.0	1.9	1.3
Total Proprietary and Brokered	5.3	4.7	4.4	4.2	3.0
Direct Sales (included in the above):					
Oil sands	0.5	0.5	0.5	0.5	0.5
Sarnia refinery	0.6	0.5	0.5	0.6	0.2
Other domestic	2.2	1.7	1.7	1.6	1.2
U.S. sales	0.9	1.0	0.7	0.3	—
Total Direct Sales	4.2	3.7	3.4	3.0	1.9

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