SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(Check One)

o Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934

or

ý Annual report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934

For fiscal year ended: **December 31, 2002**
Commission File Number: **No. 1-12384**

SUNCOR ENERGY INC.

(Exact name of registrant as specified in its charter)

Canada	**1311, 1321, 2911, 4613, 5171, 5172**	**Not Applicable**
(Province or other jurisdiction of incorporation or organization)	(Primary standard industrial classification code number, if applicable)	(I.R.S. employer identification number, if applicable)

112 - 4th Avenue S.W.
Box 38
Calgary, Alberta, Canada T2P 2V5
(403) 269-8100
(Address and telephone number of registrant's principal executive office)

CT Corporation System
111 Eighth Avenue
New York, New York, U.S.A. 10011
(212) 894-8940
(Name, address and telephone number of agent for service in the United States)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered:
Common shares	**New York Stock Exchange**

Securities registered or to be registered pursuant to Section 12(g) of the Act:

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

None

For annual reports, indicate by check mark the information filed with this form:

ý Annual Information Form ý Annual Audited Financial Statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

Common Shares	**448,971,543**
Preferred Shares, Series A	**none**

Indicate by check mark whether the registrant by filing the information contained in this form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the registrant in connection with such rule.

Yes **o** No ý

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13(a) or 15(d) of the Exchange Act during the proceeding 12 months (or for such shorter period that the registrant was required to file such reports); and (2) has been subject to such filing requirements in the past 90 days.

Yes ý No **o**

ANNUAL INFORMATION FORM

SUNCOR ENERGY INC. ANNUAL INFORMATION FORM

February 27, 2003

ANNUAL INFORMATION FORM

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GLOSSARY OF TERMS

Bitumen/Heavy Oil

A naturally occurring viscous tar-like mixture, mainly containing hydrocarbons heavier than pentane, that is not recoverable at a commercial rate in its naturally occurring viscous state through a well without using enhanced recovery methods. When extracted bitumen/heavy oil can be upgraded into crude oil and other petroleum products.

Capacity

Maximum output that can be achieved from a facility in ideal operating conditions in accordance with current design specifications.

Coal Bed Methane

Natural gas produced from wells drilled into a coal formation. Also called coal seam methane.

Conventional Crude Oil

Crude oil produced through wells by standard industry recovery methods for the production of crude oil.

Conventional Natural Gas

Natural gas produced from all geological strata, excluding coal bed methane.

Crude Oil

Unrefined liquid hydrocarbons, excluding natural gas liquids.

Downstream

This business segment manufactures, distributes and markets refined products from crude oil.

Dry Hole/Well

An exploration or development well determined, on an economic basis, to be incapable of producing hydrocarbons that will be plugged, abandoned and reclaimed.

Gross Production/Reserves

Suncor's undivided percentage interest in production/reserves before deducting Crown royalties, freehold and overriding royalty interests.

Gross Wells/Land Holdings

Total number of wells or acres, as the case may be, in which Suncor has an interest.

Heavy Fuel Oil

Residue from refining of conventional crude oil that remains after lighter products such as gasoline, petrochemicals and heating oils have been extracted.

In-situ Oil

In-situ or "in place" refers to methods of extracting heavy crude oil from deep deposits of oil sands with minimal disturbance of the ground cover.

MD&A

Suncor's Management's Discussion and Analysis dated February 27, 2003, accompanying its audited consolidated comparative financial statements, notes thereto and auditor's report thereon, as at and for the three years in the period ended December 31, 2002, which MD&A is incorporated by reference herein.

Natural Gas

Hydrocarbons that at atmospheric conditions of temperature and pressure are in a gaseous state.

Natural Gas Liquids

Hydrocarbon products recovered as liquids from raw natural gas by processing through extraction plants or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butane and pentane plus, or a combination thereof.

Net Production/Reserves

Suncor's undivided percentage interest in total production or total reserves, as the case may be, after deducting Crown royalties and freehold and overriding royalty interests.

Net Wells/Land Holdings

Suncor's undivided percentage interest in the gross number of wells or gross number of acres, as the case may be, after deducting interests of third parties.

Overburden

Material overlying oil sands that must be removed before mining. Consists of muskeg, glacial deposits and sand.

Probable Reserves

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 proved estimates that 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. Information on probable reserves included in this Annual Information Form is prepared in accordance with Canadian disclosure requirements. U.S. companies are prohibited in filings with the United States Securities and Exchange Commission to disclose estimates of probable reserves for non-mining properties. As a result our reserve estimates may not be comparable to those made by U.S. companies.

Proved Reserves

Those reserves estimated as recoverable with a high degree of certainty 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.

Reservoir

Body of porous rock containing an accumulation of water, crude oil or natural gas.

Sour Synthetic Crude Oil

Crude oil produced from oil sands that requires only partial upgrading and contains a higher sulphur content than sweet synthetic crude oil.

Sweet Synthetic Crude Oil

Crude oil produced from oil sands consisting of a blend of hydrocarbons resulting from thermal cracking and purifying of bitumen.

Synthetic Crude Oil

Upgraded or partially upgraded crude oil recovered from oil sands including surface mineable oil sands leases and in-situ heavy oil leases.

Undeveloped Oil and Natural Gas Lands

Suncor's undivided percentage interest in lands where no producing or commercially producible well has been drilled.

Upstream

These business segments include acquisition, exploration, development, production and marketing of crude oil, natural gas and natural gas liquids; and for greater clarity include the production of synthetic crude oil, bitumen and other oil products from oil sands.

Utilization

The average use of capacity taking into consideration planned and unplanned outages and maintenance.

Wells

Development Well

A crude oil or natural gas well drilled in a reservoir known to be productive and expected to produce in future.

Drilled Well

A well that has been drilled and has a defined status e.g. gas well, shut-in well, producing oil well, producing gas well, suspended well or dry and abandoned well.

Exploratory Well

A well drilled in unproved or semi-proved territory with the intention to discover commercial reservoirs or deposits of crude oil and/or natural gas.

ACCOUNTING TERMS

Barrel of Oil Equivalent (BOE)

Suncor converts natural gas to barrels of oil equivalent (BOE) at a 6:1 ratio (converted on the approximate energy equivalent basis that six million cubic feet of natural gas equals one thousand barrels of oil equivalent).

Development Costs

Includes all costs associated with moving reserves from other classes such as “proved undeveloped” and “probable” to the “proved developed” class.

Finding Costs

Includes the cost of and investment in undeveloped land, geological and geophysical activities, exploratory drilling and direct administrative costs necessary to discover crude oil and natural gas reserves.

Lifting Costs

Includes all expenses related to the operation and maintenance of producing or producible wells and related facilities, natural gas plants and gathering systems.

Million Cubic Feet Equivalent (MMCF/E)

Converts crude oil to natural gas on the approximate energy equivalent basis that one thousand barrels of crude oil equals six million cubic feet natural gas.

Net Debt

Long-term borrowings (including the current portion) plus short-term borrowings, less cash and cash equivalents.

Operating Working Capital

Current assets (excluding cash and cash equivalents), less current liabilities (excluding borrowings).

Return on Capital Employed (ROCE)

Net earnings adjusted for after-tax long-term interest expense, divided by average capital employed. Average capital employed is the total of shareholders’ equity and short-term and long-term debt, less capitalized costs of major projects in progress, at the beginning and end of the year, divided by two.

Return on Average Shareholders’ Equity

Earnings as a percentage of average shareholders’ equity. Average shareholders’ equity is the aggregate of total shareholders’ equity at the beginning and end of the year, divided by two.

CONVERSION TABLE

1 cubic metre m(3) = 6.29 barrels	1 tonne = 0.984 tons (long)
1 cubic metre m(3) (natural gas) = 35.49 cubic feet	1 tonne = 1.102 tons (short)
1 cubic metre m(3) (overburden) = 1.31 cubic yards	1 kilometre = 0.62 miles
	1 hectare = 2.5 acres

Notes:

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

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

CURRENCY

All references in this Annual Information Form to dollar amounts are in Canadian dollars unless otherwise indicated.

FORWARD-LOOKING STATEMENTS

This Annual Information Form contains certain forward-looking statements that are based on Suncor's current expectations, estimates, projections and assumptions. Forward-looking statements are made by the Company in light of its experience and its perception of historical trends.

All statements that address expectations or projections about the future, including statements about Suncor's strategy for growth, expected future expenditures, commodity prices, costs, schedules, production volumes, operating and financial results and expected impact of future contractual commitments, are forward-looking statements. Some of the forward-looking statements may be identified by words like "expects," "anticipates," "plans," "intends," "believes," "projects," "indicates," "could", "vision", "goal", "target", "objective" and similar expressions. These statements are not guarantees of future performance as they are based on assumptions and involve a number of risks and uncertainties, some of which are similar to those that affect other oil and gas companies, and some of which are unique to Suncor. Therefore, Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements and you are cautioned not to place undue reliance on them.

The risks, uncertainties and other factors that could influence actual results include but are not limited to: changes in general economic, market and business conditions; fluctuations in supply and demand for Suncor's products; fluctuations in commodity prices; fluctuations in currency exchange rates; Suncor's ability to respond to changing markets; the ability of Suncor to receive timely regulatory approvals; the successful and timely implementation of its growth projects including the Firebag In-Situ Oil Sands Project and Voyageur; the integrity and reliability of Suncor's capital assets; the cumulative impact of other future resource developments; the accuracy of Suncor's reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations, strategic partners and joint venture co-owners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; the uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of or changes to taxes, fees and royalties, and changes in environmental and other regulations; the ability and willingness of parties with whom Suncor has material relationships to perform their obligations to Suncor; and the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor. The foregoing important factors are not exhaustive.

Many of these risk factors and other specific risks and uncertainties are discussed in further detail throughout this Annual Information Form and in Suncor's MD&A, incorporated by reference herein. Readers are also referred to the risk factors described in other documents Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the Company at 112 — 4th Avenue S.W., Calgary, Alberta, T2P 2V5, by calling 1-800-558-9071, or by email request to info@suncor.com.

References herein to Suncor's 2002 Consolidated Financial Statements mean Suncor's audited consolidated comparative financial statements, notes thereto and auditor's report thereon, as at and for the three years in the period ended December 31, 2002.

CORPORATE STRUCTURE

Name and Incorporation

Suncor Energy Inc. (formerly 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*. Suncor's articles were amended in 1995 to move its registered office from Toronto, Ontario, to Calgary, Alberta, and amended again in April 1997, to adopt its current name, "Suncor Energy Inc.". In April 1997, May 2000 and May 2002, Suncor's articles were amended to divide its issued and outstanding shares on a two-for-one basis.

Suncor's registered and principal office is located at 112 - 4th Avenue, S.W. Calgary, Alberta, T2P 2V5.

In this Annual Information Form, references to "Suncor" or the "Company" include Suncor Energy Inc., its subsidiaries and joint venture investments unless the context otherwise requires.

Intercorporate Relationships

Suncor Energy Inc. has two principal subsidiaries.

Suncor Energy Products Inc. ("SEPI") (formerly Sunoco Inc.) is an Ontario corporation that is wholly-owned by Suncor. SEPI refines and markets petroleum products and petrochemicals directly and indirectly through subsidiaries and joint ventures. SEPI operates its retail business under the Sunoco brand in Canada. SEPI is unrelated to Sunoco, Inc. (formerly known as Sun Company, Inc.), headquartered in Philadelphia, Pennsylvania.

Suncor Energy Marketing Inc., wholly-owned by SEPI, is incorporated under the laws of Alberta. Suncor Energy Marketing Inc. markets, mainly to customers in Canada and the United States, the crude oil, diesel fuel and byproducts such as petroleum coke, sulphur and gypsum, produced by Suncor's Oil Sands business unit. It also markets certain third party products, and procures crude oil feedstocks for Suncor's downstream

business. Suncor Energy Marketing Inc. also has a petrochemical marketing division that holds a 50% interest in Sun Petrochemicals Company, a petrochemical products joint venture. Commencing in 2002, Suncor Energy Marketing Inc. procures the natural gas supply for Suncor's Oil Sands and Energy Marketing and Refining ("EM&R") businesses, and administers Suncor's energy trading activities. Commencing in 2003, it will also market certain natural gas produced by Suncor's Natural Gas ("NG") business unit.

Suncor has a number of other subsidiary companies. However, the total assets of such subsidiaries combined, and their total sales and operating revenues, do not constitute more than 20 per cent of the consolidated assets, or consolidated sales and operating revenues, respectively, of Suncor.

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Suncor is a Canadian-based integrated energy company. Suncor explores for, acquires, develops, produces and markets crude oil and natural gas, refines crude oil and markets petroleum and petrochemical products. Periodically Suncor also markets third party petroleum products. In the fourth quarter of 2002, Suncor commenced energy trading activities focused principally on buying and selling futures contracts and other derivative instruments based on the commodities Suncor produces. These activities are intended to earn revenues for the Company and improve market intelligence as Suncor increases production levels.

Suncor has three principal operating business units. Oil Sands (OS), based near Fort McMurray, Alberta, mines oil sands ore and extracts and upgrades bitumen into sweet and sour crude oil, diesel fuel and refinery feedstock. Natural Gas ("NG"), based in Calgary, Alberta, explores for, acquires, develops and produces natural gas. Energy Marketing and Refining ("EM&R"), headquartered in Toronto, Ontario, refines crude oil at Suncor's refinery in Sarnia, Ontario, into a broad range of petroleum products, and markets the company's refined products to industrial, wholesale and commercial customers principally in Ontario and Quebec, and to retail customers in Ontario through Sunoco-branded and joint venture operated retail networks.

While it provides hydrocarbon-based resources for the immediate energy needs of consumers, Suncor also pursues the development of low-emission and no-emission energy sources that have a reduced environmental impact. Segmented financial data for these activities is reported under the results of Suncor's "Corporate" segment for financial reporting purposes.

In 2002, Suncor produced approximately 239,500 BOE per day, comprised of 209,700 barrels per day (bpd) of crude oil and natural gas liquids and 179 million cubic feet per day of natural gas. In 2001, the most recent period with published results, Suncor was the 5th largest crude oil (approximately 6% of Canada's crude oil production) and natural gas liquids producer and the 21st largest natural gas producer in Canada. Production in 2001 was 156,600 BOE per day and reflects the commissioning of Project Millennium in the fourth quarter, as described below under "Three Year History — Oil Sands".

In 2002, Suncor sold approximately 91,100 bpd (2001 - 93,400 bpd) or 14,500 m^3 per day (2001 - 14,800 m^3 per day) of refined products, mainly in Ontario but also in the United States and Europe. Suncor's refined product sales in Ontario represented approximately 17% (2001-18%) of Ontario's total refined product sales in 2002.

Three-Year Highlights

Oil Sands (OS)

In April 1999, following approval from Suncor's Board of Directors and regulatory authorities, Suncor commenced construction of Project Millennium, an expansion of its Oil Sands plant near Fort McMurray, Alberta. Through an expanded mine, additional mining equipment, increased energy services support and twinning of the bitumen extraction and upgrading process, Project Millennium was completed in 2001 and increased total design capacity of Suncor's Oil Sands plant to 225,000 bpd. The final capital cost of Project Millennium was $3.4 billion, up from the original estimate of $2 billion. The increase in project costs over earlier estimates was primarily attributable to rising labour, fabrication and material costs and a $150 million change in the project's scope. The capital costs were financed by internally generated cash flow and additional borrowings.

In early 2000, Suncor announced a plan to further expand its Oil Sands operations beyond Project Millennium and in 2001 Suncor received regulatory approval to proceed with development of a four stage in-situ oil sands project on its Firebag oil sands leases (the "Firebag Project"). The approval is conditioned on providing the regulators with project updates at least six months prior to any development on each stage after stage one. The first stage of the Firebag Project is expected to begin commercial bitumen production in 2004. Full production from the first stage, targeted at 35,000 barrels per day of bitumen, is not expected until mid-2005. Combined with associated investments in the upgrading facility, the first stage of the Firebag Project is expected to contribute to a planned increase in total Oil Sands production capacity to 260,000 bpd in 2005. The first stage of the Firebag Project and associated addition of a vacuum unit to the Oil Sands Millennium upgrader are estimated to cost a total of approximately $1 billion. Engineering is underway on the second stage of the Firebag Project, with front-end engineering design specifications targeted for completion in the second quarter of 2003. Suncor plans to spend over $490 million on Oil Sands growth projects in 2003, primarily related to the Firebag Project and Millennium vacuum unit. Approval from Suncor's Board of Directors is required before construction beyond the first stage of the Firebag Project can begin. The combined bitumen production potential of all four stages of the Firebag In-situ Oil Sands Project is 140,000 bpd.

In late 2001, Suncor issued a public disclosure document for its Voyageur growth strategy, which targets production between 500,000 bpd to 550,000 bpd in 2010 to 2012. When Suncor originally released these plans, the Company stated it would apply for regulatory approval in late 2002. Following initial stakeholder consultation and preliminary engineering, Suncor modified its Voyageur plan, deferring applications for regulatory approval until further details about each project stage are known and can be more fully discussed with stakeholders. Although the timing of Suncor's regulatory approval strategy has changed, the Company's goal of increasing production capacity to 500,000 to 550,000 in 2010 to 2012 remains unchanged. Suncor anticipates it will provide cost estimates for the Voyageur growth strategy once preliminary engineering is completed for each phase. Ultimate development of the Voyageur growth project requires approval of government regulators and Suncor's Board of Directors.

In 2001, Suncor commenced a crude oil brokerage business to generate additional income by buying and selling the crude oil and bitumen production of other companies. The activity conducted by this business, which increased OS revenue by $146 million in 2002, did not have a significant impact on the Company's earnings or cash flow in 2002.

On December 17, 2002, the Government of Canada announced its ratification of the Kyoto Protocol. For a discussion of the Kyoto Protocol and management's assessment of its possible impact on Suncor, refer to the "Outlook — Climate Change" section under "Suncor Overview and Strategic Priorities", in MD&A.

Natural Gas (NG)

In April 2000, Suncor's Board of Directors approved a repositioning of Suncor's conventional oil and gas business, to sharpen Suncor's focus on natural gas production to meet growing demand, both internally and externally. During 2000, natural gas production was consolidated into three core natural gas areas in Western Canada, and Suncor sold most of its conventional crude oil properties. Since 2000, NG has decreased its annualized operating costs by approximately $20 million, through a focus on administrative cost controls and reduced lifting costs.

NG's long-term goal is to achieve a sustainable return on capital employed (ROCE) of a minimum of 12% at mid-cycle natural gas prices (US$3.00 to US$3.50/mcf). In 2002 the return on capital employed was 9.2%. To help meet its ROCE target, management plans to increase production and continue work to improve base business efficiency, with a focus on reducing operating costs and capturing supply chain management benefits.

Energy Marketing & Refining (EM&R)

In 2001, EM&R entered into a 20-year energy supply agreement with TransAlta Corporation ("TransAlta"). Under the agreement, the TransAlta Sarnia Regional Co-generation Project, a multi-user cogeneration project in Sarnia, Ontario, that commenced operation in the fourth quarter of 2002, supplies all of the steam and electricity requirements of EM&R's Sarnia Refinery. The agreement is expected to help mitigate EM&R's exposure to increases in energy costs and supply steam to the Sarnia Refinery at a competitive cost, while eliminating the need for EM&R to build its own steam generating boilers.

Federal legislation passed in 1999 mandates sulphur levels in gasoline of an average of 150 parts per million (ppm) from mid-2002 to the end of 2004, and a maximum of 30 ppm by 2005. EM&R finalized an investment plan in 2001 to meet these sulphur content limits. Capital required to achieve compliance is expected to be approximately $40 million, which includes the addition of a desulphurization unit. Construction of the unit is in progress and is expected to be completed in 2003, more than a year in advance of the legislated deadline. As of the end of 2002, $17 million had been spent on the gasoline desulphurization project.

In 2002, the Canadian government also passed legislation limiting the concentration of sulphur in diesel fuel produced or imported for use in on-road vehicles to a maximum of 15 ppm after May 31, 2006. The current maximum is 500 ppm. The cost to comply with these requirements is currently estimated at $225 million.

Regulations reducing sulphur in off-road diesel and light fuel oil are also expected to take effect later in the decade. At this time it is not possible to assess the impact these expected regulations may have on EM&R. The ultimate cost to comply may vary as details of the regulations are announced.

In addition, EM&R is evaluating several strategic options including the potential to enhance integration of the Sarnia Refinery with production from Oil Sands, and to possibly increase value through integration with the diesel desulphurization facilities.

In the second quarter of 2002, to sharpen its focus on refining and marketing, EM&R sold its retail natural gas marketing business, resulting in an after-tax gain of $35 million. EM&R entered the retail natural gas marketing business in 1997. At the time of sale, the business was supplying natural gas to approximately 125,000 commercial and residential customer accounts in Ontario.

Other

Financing Activities

During 2000, the Company put in place a fully revolving 364 day borrowing facility for $500 million. In 2001 this facility was extended to June 2002 and increased to $550 million. The borrowing facility matured in June 2002 and was not renewed.

In 2001 Suncor issued $500 million of Series 2 Medium Term Notes with a ten-year maturity. The notes have a coupon of 6.7% and will yield 6.74%.

In January 2002, Suncor issued U.S. $500 million principal amount of 7.15% unsecured notes due February 1, 2032, to investors in the United States (the "U.S."). The notes were sold at a price of 99.595% per note to yield 7.183% to maturity. The notes were sold under Suncor's shelf

prospectus dated January 10, 2002, which allows for the issuance of debt securities and common shares in an aggregate principal amount of up to U.S. $1 billion. Also in January 2002, Suncor filed a base shelf prospectus with Canadian securities regulatory authorities, enabling it to issue up to a further $500 million in medium term notes in Canada, if required. To date, no notes have been issued under this prospectus.

Sale of Stuart Oil Shale Project

In April 2001, Suncor sold its interest in the Stuart Oil Shale Project to its Australian joint venture co-owners, Southern Pacific Petroleum NL ("SPP") and Central Pacific Minerals NL ("CPM") (together, "SPP/CPM"). The first stage of the Queensland, Australia project, originally announced in 1997, was designed as a 4,500 barrel per day demonstration plant to test the commercial viability of producing crude oil from oil shale. Construction of the demonstration plant was completed and commissioning commenced in 1999. Operational issues were experienced during commissioning, including issues relating to plant reliability, noise, odours and the discovery of low levels of dioxin and other emissions. In the third quarter of 2000, Suncor recorded an after-tax write-down of $80 million, reflecting increased costs and delayed oil production, and thereafter, all future expenditures on the Project were expensed. Suncor's investment in the Project up to the date of sale, excluding $4 million invested by Suncor in partially paid SPP/CPM shares that were cancelled as part of the sale transaction, and $5 million in shares acquired in 2001, as discussed below, was approximately $275 million.

Under the terms of the sale, Suncor retained a 5% royalty interest in the first stage of the project, and SPP/CPM and Suncor retained worldwide rights to the project technology. Suncor made total payments as part of the transaction in the amount of Aus$7 million (approximately Cdn$5 million) for which Suncor received 2.5 million SPP shares and 0.926 million CPM shares. In addition, SPP/CPM issued to Suncor 12.5 million SPP share options and 4.6 million CPM share options, and Suncor surrendered the partly paid SPP/CPM restricted class shares it had originally acquired in 1997.

As a result of the sale Suncor recorded an after-tax charge to earnings of $3 million in the second quarter of 2001. Since completion of this transaction, Suncor has written-down the carrying value of the shares acquired by $4 million, to an amount of less than $1 million, and as of February 27, 2003, has liquidated approximately half of its SPP/CPM shares.

Other Three Year Highlights

In 2000, Suncor announced plans to invest at least $100 million over five years to pursue renewable energy opportunities. As of December 31, 2002, Suncor had expended approximately $17 million with the majority of these funds related to the SunBridge Wind Power Project in Gull Lake, Saskatchewan. This project is a 50-50 partnership with Enbridge Inc. ("Enbridge"). In 2001, the first electricity was generated from this project.

In 2002, Suncor's Board of Directors approved commencement of energy trading activities and after developing an appropriate control framework, Suncor began limited energy trading activities in November 2002. A separate risk management function directs and monitors practices and policies and provides independent verification and valuation of Suncor's trading and marketing activities. Trading activities are principally focused on the commodities the Company produces, adding potential for new revenue and providing a new window into energy product markets. Net trading losses were negligible for the period ended December 31, 2002.

For further information on developments and issues referred to above and other highlights of 2002, and a discussion of other trends known to Suncor's management that could reasonably be expected to have a material effect on Suncor, refer to the "Outlook" and other sections of Suncor's MD&A, and to "Risk/Success Factors" in this Annual Information Form.

NARRATIVE DESCRIPTION OF THE BUSINESS

OIL SANDS

Suncor produces a variety of refinery feedstock and diesel fuel by mining the Athabasca oil sands in northeastern Alberta and upgrading the bitumen extracted at its plant near Fort McMurray, Alberta. The Oil Sands operations, accounting for virtually all of Suncor's conventional and synthetic crude oil production in 2002, represents a significant portion of Suncor's 2002 capital employed (83%), cash flow (85%) and net earnings (89%).

Operations

Suncor's integrated Oil Sands business involves four operations: a mining operation using trucks and shovels to mine the oil sand ore; extraction facilities to recover the bitumen from the oil sand ore; a heavy oil upgrading process, where bitumen is converted into crude oil products; and energy services facilities (operated by TransAlta), which together with TransAlta's natural gas fired co-generation plant that commenced operations at the Oil Sands plant site in 2001, provides the site with steam and electric power. Suncor's energy services plant primarily uses petroleum coke, a by-product of the coking process, as fuel. It also consumes natural gas. Suncor uses all of the steam and a portion of the power from the TransAlta cogeneration facility.

The first step of the open pit mining operation is to remove the overburden with trucks and shovels to access the oil sands - a mixture of sand, clay and bitumen. Oil sands ore is then excavated, and transported to one of five sizing plants by a fleet of trucks. The ore is dumped into sizers where it is crushed and sent to the ore preparation plants where it is mixed into a hot water slurry and pumped through hydrotransport pipelines to the extraction plant on the west side of the Athabasca River. The bitumen begins to separate from the sand as the slurry is pumped through the lines. Bitumen is extracted from the oil sands ore with a hot water process. After the final removal of impurities and minerals, naphtha is added to the bitumen as diluent to facilitate transportation to the upgrading plant. Periodically bitumen is sold rather than being upgraded. In 2001 approximately 8,500 bpd of bitumen were sold, representing approximately seven percent of 2001 production. In 2002 bitumen sales of 9,300 bpd represented five percent of sales.

After transfer of the diluted bitumen to the upgrading plant, the naphtha is removed and recycled to be used again as diluent. The bitumen is upgraded through a coking and distillation process. The upgraded product, referred to as sour crude oil, is either sold directly to customers or is further upgraded into sweet crude oil by removing the sulphur and nitrogen using a hydrogen treating process. Three separate streams of refined crude oil are produced: naphtha, kerosene and gas oil.

While there is virtually no finding cost associated with synthetic crude oil, mine development and expansion of production can entail significant outlays of funds. The costs associated with synthetic crude oil production are largely fixed for the same reason and, as a result, operating costs per unit are largely dependent on levels of production. Operating costs to produce synthetic crude oil are generally higher than lifting and administrative costs to produce conventional crude oil from the Western Canada Sedimentary Basin.

Transportation

Oil Sands entered into a transportation service agreement with a subsidiary of Enbridge for a term that commenced in 1999 and extends to 2028. Under the agreement Suncor has pipeline capacity for the initial shipment of 60,000 bpd in 1999, increasing to 170,000 bpd in 2005, of sour crude oil and bitumen from Fort McMurray, Alberta to Hardisty, Alberta. As the initial shipper on the pipeline, Suncor's tolls payable under the agreement are subject to annual adjustments. The pipeline was initially operated by Suncor Energy Marketing Inc. and is now operated by Enbridge. This pipeline, together with Suncor's proprietary oil sands pipeline, is expected to meet Suncor's anticipated crude oil shipping requirements for expected future production levels up to 2008. Suncor Energy Marketing Inc., a subsidiary of Suncor, purchases all crude oil products from Suncor's Oil Sands business at Hardisty and markets the product blends for sale and distribution to Suncor's Sarnia, Ontario refinery, as well as other customers in Canada, the United States and periodically, to offshore markets.

Suncor has a 20 year agreement with TransCanada Pipeline Ventures Limited Partnership ("TCPV"), to provide Suncor with firm capacity on a natural gas pipeline that came into service in 1999. The natural gas pipeline ships natural gas to Suncor's Oil Sands facility.

Suncor's oil sands facilities are readily accessible by public road.

Competitive Conditions

Competitive conditions affecting Oil Sands are described under the heading "Competition" in the "Risk/Success Factors" section of this Annual Information Form.

Seasonal Impacts

Severe climatic conditions at Oil Sands can cause reduced production and in some situations result in higher costs.

Location of Production and Material Properties

Set out in the table below is a summary of Suncor's oil sands mining and in-situ leasehold interests as of December 31, 2002.

Description	Legal Description	Referred to as	Number of Gross Acres	Percentage of Proved Reserves (bbl of synthetic crude oil)(5)
Mining Leases:				
Leases:	7280100T25	25	17,066	
	7279080T19	19	18,760	These Leases
	7597030T11	97	2,483	combined represent
	7280060T23		36,954	100% of proved mining
	7498050014		243	reserves
	7400120007		22,773	
Fee Lots(1)	1	N/A	1,894	(1)
	2	N/A	1,972	(1)
	3	N/A	1,967	(1)
	4	N/A	1,886	(1)
	5	N/A	1,881	(1)
	6	N/A	1,483	(1)
				(1)
Original Mine	7387060T04	86	4,522	
Leases(2)	7279120092	17	1,619	None
Total Mining Leases			**115,503**	
Firebag Leases:				
Firebag(3)	7285100T85	85	39,594	25% of proved in-situ reserves

	7402110457	N/A	23,040	10% of proved in-situ reserves
	7402110458	N/A	22,720	65% of proved in-situ reserves
	7402110459	N/A	23,040	(1)
	7099120072	N/A	23,040	(1)
	7099120073	N/A	23,040	(1)
	7099120074	N/A	16,640	(1)
	7099120075	N/A	23,040	(1)
	7001100001	N/A	22,400	(1)
	7401100027	N/A	23,040	(1)
	7401100029	N/A	10,240	(1)
	7401100013	N/A	7,360	(1)
Firebag(3)	Various(4)	Various	84,480	(1)
Total Firebag Leases			**341,674**	
Total Leases			**457,177**	

Notes:

(1) No proved reserves are attributable to these leases.

(2) Mining on these leases was substantially complete at the end of 2002.

(3) Leases are principally in-situ.

(4) Suncor holds a beneficial interest in 13 leases totaling 84,480 gross and net acres.

(5) In 2002, 100% of Suncor's Oil Sands production was from the mining leases referred to above, located adjacent to Suncor's Oil Sands facilities north of Fort McMurray, Alberta.

The Government of Alberta is entitled to royalties under Leases 17, 19, 25, 86 and 97 and the Fee Lots at rates which the Government establishes from time to time. For a description of the Alberta Crown Royalty regime applicable to these leases, and other applicable royalties, refer to "Royalties" in the "Oil Sands Overview" section of MD&A.

Reserves Estimates

In a report dated January 15, 2003, Gilbert Laustsen Jung Associates Ltd. ("GLJ"), independent petroleum consultants, audited Suncor's estimates of proved and probable reserves, as of December 31, 2002, of synthetic crude oil on its oil sands mining leases. In a report dated January 24, 2003, GLJ prepared an independent reserves and economic evaluation of Suncor's in-situ oil sands Firebag Project leases, also as of December 31, 2002 (together, the "GLJ Oil Sands Reports"). In the GLJ Oil Sands Reports, GLJ estimates Suncor's proved plus probable reserves of synthetic crude oil from oil sands mining and in-situ leases total 3.761 billion barrels. This total includes estimates from Suncor's mining leases that account for 358 million barrels of proved and 1.563 billion barrels of probable reserves, as well as in-situ leases containing 144 million barrels of proved and 1.696 billion barrels of probable reserves. These values are before deduction of Crown and other royalties on the leases.

In the GLJ Oil Sands Reports, GLJ state that they believe there is a 90% and 50% probability under current economic conditions that the quantities actually recovered will equal or exceed the estimated proved and proved plus probable reserves estimates, respectively. GLJ's estimates consider recovery from leases for which regulatory approvals have been granted.

The mining reserve estimates are based upon a detailed geological assessment and also consider drill density, production capacity, extraction recoveries, upgrading yields, mine plans, operating life, and regulatory constraints. The proved reserves estimate considers portions of the mines drilled up to a density of at least 10 holes per square kilometer, which are expected to be mined in the near future. For Firebag proved reserve estimates, GLJ considered similar factors such as Suncor's regulatory approval, detailed design estimates, detailed reservoir studies, demonstrated commercial success of analogous commercial projects, and a required drilling density of at least 80 acre spacing plus 3D seismic control.

Suncor's reserves estimates will continue to be impacted by both drilling data and operating experience, as well as technological developments and economic considerations.

Reserves Reconciliation

The following table sets out a reconciliation of Suncor's proved and probable reserves of synthetic crude oil from December 31, 2001 to December 31, 2002, based on the GLJ Oil Sands Reports.

(millions of barrels of synthetic crude oil)(1)	Oil Sands Mining Leases			In-Situ Firebag Leases(2)			Total Mining and In-Situ
	Proved(3)	Probable(4)	Proved & Probable(4)	Proved(3)	Probable(4)	Proved & Probable(4)	Proved & Probable(4)
December 31, 2001	376	2,029	2,405	—	1,664	1,664	4,069
Revisions	54	(511)(5)	(457)(5)	—	—	—	(457)
Additions	3	45	48	144	32	176	224
Production	(75)	—	(75)	—	—	—	(75)
December 31, 2002	358	1,563	1,921	144	1,696	1,840	3,761

Notes:

(1) Synthetic crude oil reserves based upon a net coker, or synthetic crude oil yield of between 80% and 82%.

(2) Suncor has the option of selling the bitumen production from these leases and/or upgrading the bitumen to synthetic crude oil. The opening balance has been adjusted from a bitumen value of 2.029 billion barrels based on assumed coker (synthetic crude) yields. See note (1). The reserve estimates for the in-situ leases reflect reclassification of a portion of probable reserves to proved now that the first stage of construction of the Firebag Project is nearly complete. The increase also reflects data obtained from similar industry projects that have recently demonstrated commercial success of the in-situ oil sands development process. Suncor will continue to conduct its evaluation program in the Firebag area in 2003, utilizing a combination of seismic and corehole drilling. To date Suncor has drilled approximately 300 coreholes and acquired approximately 400 miles of seismic data in the Firebag area.

(3) All of Suncor's proved mining reserves are classified as proved producing reserves; all of Suncor's in—situ Firebag proved reserves are classified as proved non-producing reserves.

(4) In the GLJ Oil Sands Reports, GLJ state that they believe there is at least a 50% probability that proved plus probable oil sands reserves estimates will be exceeded. Accordingly, Suncor's oil sands reserves have not been further reduced for risk associated with obtaining production from such reserves.

(5) Approximately half of this probable reserve revision reflects management's decision not to mine less economic areas, as permitted by regulatory changes. The balance of the revision incorporates additional knowledge and understanding of the Millennium mine. For more details, see the information under "Critical Accounting Policies - Oil Sands Mining Reserves" in the Corporate Overview and Strategic Priorities section of Suncor's MD&A. GLJ estimates that Suncor's 1.921 billion barrels of proved plus probable mining reserves provide Suncor with approximately 24 years of operations at current production rates.

Sales of Synthetic Crude Oil and Diesel

Aside from onsite fuel use, all of Oil Sands' production is sold to Suncor Energy Marketing Inc., a wholly owned subsidiary, which then markets all production.

In 1997 Suncor entered into a long-term agreement with Koch Oil Co. Ltd. ("Koch") to supply Koch with up to 30,000 barrels per day (approximately 15% of Suncor's average 2002 total production) of sour

crude from Suncor's Oil Sands operation. Suncor began shipping the crude to Koch's terminal at Hardisty (from which Koch ships the product to its refinery in Minnesota) under this long-term agreement effective January 1, 1999. The initial term of the agreement extends to January 1, 2009, with month to month evergreen terms thereafter, subject to termination after January 1, 2004, on twenty-four months' notice.

In 2000, Suncor announced a long term sales agreement with Consumers' Co-operative Refineries Limited ("CCRL") under which Suncor expected to begin supplying CCRL with 20,000 barrels per day of sour crude oil production from its Project Millennium expansion facilities by late 2002. CCRL has experienced construction delays with an expansion of its refinery in Regina, Saskatchewan, and is expected to begin accepting delivery of sour crude in the second quarter of 2003.

Prices for sour crude oil under these agreements are set at agreed differentials to market benchmarks.

In 2001, Suncor announced a long-term agreement with Petro-Canada to supply up to 30,000 barrels per day of diluent to dilute bitumen produced by Petro-Canada. Deliveries under the contract have commenced. The agreement is for four years and may be extended unless terminated by either party.

In 2001 and 2002, Koch was the only customer that represented 10% or more of Suncor's consolidated revenues.

A portion of Oil Sands production is used in connection with Suncor's Sarnia refining operations. During 2002, the Sarnia refinery processed approximately 12% (2001 — 14%) of Oil Sands crude oil production.

The following table sets forth the average sales price received per barrel of synthetic crude oil from Oil Sands on a quarterly basis for the years 2002 and 2001, after the impact of hedging activities.

	2002	2001

$/bbl	4Q	3Q	2Q	1Q	4Q	3Q	2Q	1Q
Average sales price	35.12	35.79	33.43	29.66	24.43	31.43	31.40	30.84

Capital Expenditures

Capital spending at Oil Sands is expected to total approximately $710 million in 2003, comprising $496 million with respect to the in-situ phase of Suncor's Oil Sands development and expansion of the upgrading facilities and $215 million in capital investments for the current facility, including approximately $70 million for the second quarter maintenance shutdown (see MD&A for details). Capital expenditures in 2002 were $630 million.

Suncor's in-situ and expansion of upgrading facilities spending of $341 million in 2002 is part of $1 billion in total spending on in-situ projects planned for the period 2002 to 2005.

The following table sets out, for the quarters indicated, capital expenditures by Suncor's Oil Sands business unit:

	2002				2001			
Capital Expenditures by quarter	4Q	3Q	2Q	1Q	4Q	3Q	2Q	1Q
Property acquisitions	—	—	—	—	4	—	—	9
Drilling activity	(7)	1	—	17	4	—	4	14
Capital Additions to Facilities(1)	208	149	114	135	305	384	392	363

Note:

(1) Includes capital spending on Project Millennium, Firebag Project, acquisition of mining equipment, and other capital spending.

Environmental Compliance

For a description of the impact of environmental protection requirements on Oil Sands, refer to "Environmental Regulation and Risk" and "Governmental Regulation" in the "Risk/Success Factors" section of this Annual Information Form, and "Reclamation and Environmental Remediation Cost" under "Critical Accounting Policies" in the "Suncor Overview and Strategic Priorities" section of MD&A.

NATURAL GAS

Suncor's Natural Gas business, based in Calgary, Alberta, explores for, develops and produces conventional natural gas in western Canada, supplying it to markets throughout North America. The sale of NG production provides a price hedge for natural gas consumption at Suncor's Oil Sands facility and its refinery in Sarnia, Ontario. In addition, Suncor's U.S. subsidiary, Suncor Energy (Natural Gas) America Inc., is acquiring land and exploring for coal bed methane in the United States.

Exiting 2002, natural gas and natural gas liquids accounted for approximately 96% of the NG business unit's production.

NG's exploration program is focused on multiple geological zones in three core asset areas: Northern (northeast British Columbia and northwest Alberta), Foothills (western Alberta and portions of northeast British Columbia) and Central Alberta. Suncor drills primarily medium to high-risk wells focusing on prospects that can be connected to existing infrastructure.

Commencing in 2003, all of NG's natural gas production, excluding sales to aggregators, will be sold to Suncor's marketing subsidiary, Suncor Energy Marketing Inc., which sells both Suncor's proprietary natural gas and natural gas acquired from other producers.

In June 2002, Suncor entered into a short-term agreement with UBS Warburg to provide Suncor with operational and administrative services related to its natural gas portfolio. UBS continues to provide these services under this agreement. Prior to the agreement with UBS Warburg, these services were provided by Enron Capital and Trade Resources Canada Corp.

Reserves and Reserves Reconciliation

GLJ reported January 22, 2003, on Suncor's estimated proved and probable reserves of natural gas, natural gas liquids and crude oil (other than reserves from Suncor's mining leases and the Firebag in-situ reserves), as of December 31, 2002. Information with respect to these reserves is set out in the tables below and in the tables under the headings "Conventional Crude Oil", "Natural Gas Liquids" and "Natural Gas" (the "Reserves Tables"). GLJ's determination of Suncor's estimated proved and probable recoverable reserves are based on constant year-end prices and costs determined 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 are considered reasonable, the estimates should be viewed with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

In the Reserves Tables:

(1) Proved reserves and probable reserves have the meanings set out in the Glossary of Terms at the front of this Annual Information Form. All proved and probable reserves are in Canada.

(2) Proved producing reserves are on production, or reserves that could be recovered from existing wells or facilities, where the current non-producing status is the choice of Suncor.

(3) Gross reserves represent the aggregate of Suncor's undivided percentage 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 that 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 revision.

The following tables set out a reconciliation of NG's estimated proved reserves from December 31, 2001 to December 31, 2002.

Estimated Proved Reserves Reconciliation (1)

	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)
December 31, 2001	14(1)	755	10	545
Revisions of previous estimates	—	(35)	—	(18)
Extension and discoveries	1	53	1	39
Production	(1)	(65)	(1)	(48)
Sales of minerals in place	—	(2)	—	(2)
December 31, 2002	14(1)	706	10	516

Note:

(1) Includes 8.7 million barrels of natural gas liquids as at December 31, 2002 (8.6 million barrels as at December 31, 2001).

Estimated proved reserves are comprised of producing and non-producing reserves. The following tables show the breakdown between these categories.

Estimated Proved Producing Reserves Reconciliation

	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)
December 31, 2001	11	573	8	416
Revisions of previous estimates	—	—	—	3
Extension and discoveries	1	77	1	56
Production	(1)	(65)	(1)	(48)
Sales of minerals in place	—	(1)	—	(1)
December 31, 2002	11	584	8	426

Estimated Proved Non-Producing Reserves Reconciliation

	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)
December 31, 2001	3	182	2	129
Revisions of previous estimates	—	(35)	—	(21)
Extension and discoveries	—	(24)	—	(17)
Sales of minerals in place	—	(1)	—	(1)
December 31, 2002	3	122	2	90

The following table sets out a reconciliation of NG's estimated probable reserves from December 31, 2001 to December 31, 2002.

Estimated Probable Reserves Reconciliation (1)

	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)
December 31, 2001	6	237	5	169
Revisions of previous estimates	(1)	(33)	(1)	(21)
Extension and discoveries	—	14	—	10
Sales of minerals in place	—	—	—	—
December 31, 2002	5	218	4	158

Note:

(1) The total probable reserves of natural gas shown in the above table have not been reduced for risk associated with the probability of obtaining production from such reserves. Application of a risk factor of 50% to the above reserves would reduce the reserves numbers in the table to 2.5 million barrels of crude oil and natural gas liquids (2 million net), and 109 billion cubic feet of natural gas (79 million net).

Conventional Crude Oil

The following table shows estimates of NG's proved crude oil reserves before royalties as prepared by GLJ (see "Reserves and Reserves Reconciliation") and Suncor's average daily production of crude oil before royalties, in Alberta and British Columbia, represented by the conventional fields identified in this table.

Fields	Proved Reserves Before Royalties December 31, 2002(1) (millions of barrels)	%	2002 Average Daily Production Before Royalties(1) (barrels of oil per day)	%
Simonette	2.1	42	539	36
Blueberry	1.8	36	342	23
McKinley	0.4	8	359	24
Bonanza	0.2	4	41	3
Boundary Lake	0.2	4	28	2
Other(2)	0.3	6	177	12
Total — gross	5.0	100	1,486	100

Notes:

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

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

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 subject to natural decline. In some cases, additional amounts of crude oil can be recovered by using various methods of enhanced crude oil recovery, infill drilling and production optimization techniques. At the end of 2002, approximately 90% of Suncor's proved conventional oil reserves were under enhanced oil recovery programs.

Natural Gas Liquids

The following table shows estimates of NG's proved natural gas liquids reserves before royalties as prepared by GLJ (see "Reserves and Reserves Reconciliation") and Suncor's average daily production of natural gas liquids before royalties, in Alberta and British Columbia, represented by the conventional fields identified in this table.

Fields	Proved Reserves Before Royalties December 31, 2002 (millions of barrels)	%	2002 Average Daily Production Before Royalties (barrels per day)	%
Simonette	2.4	27	505	21
Grande Prairie	1.5	17	197	8
Knopcik	0.9	10	278	12
Pine Creek	0.8	9	209	9
Glacier	0.6	7	175	7
Blueberry	0.5	6	164	7
Stolberg	0.4	4	65	3
Rosevear	0.4	4	216	9
Boundary Lake	0.3	3		
Blackstone	0.2	2	65	3
Phoenix	0.2	2	35	1
George	0.1	1	235	10
Hinton	0.1	1	42	2
Other(1)	0.6	7	203	8

Total — gross	9.0	100	2,389	100

Note:

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

Natural Gas

The following table shows estimates of NG's proved natural gas reserves, before royalties, as prepared by GLJ (see "Reserves and Reserves Reconciliation") and Suncor's average daily production of natural gas before royalties, in Alberta and British Columbia, represented by the major natural gas fields identified in the table.

	Proved Reserves Before Royalties December 31, 2002		2002 Average Daily Production Before Royalties	
Fields	(billions of cubic feet)	%	(millions of cubic feet per day)	%
Stolberg	228	32	34	19
Blackstone/Brown Creek	66	9	19	11
Grande Prairie area	55	8	6	3
Knopcik	47	7	14	8
Glacier	43	6	14	8
Simonette	42	6	9	5
Blueberry	38	5	9	5
Mountain Park	32	5	11	6
Rosevear	29	4	18	10
Pine Creek	19	3	6	3
Sinclair	19	3	5	3
Cutbank	13	2	9	5
Other(1)	75	10	25	14
Total — gross	706	100	179	100

Note:

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

Land Holdings

The following table sets out the undeveloped and developed lands in which the NG business unit held crude oil and natural gas interests at the end of 2002. Undeveloped lands are lands within their primary term upon which no well has been drilled. Developed lands are lands past their primary term or upon which a well has been drilled.

The petroleum and natural gas interests include Suncor's undivided percentage interest in leases, licenses, reservations, permits and exploration agreements (collectively, the "Agreements"). In general, Agreements confer upon the lessee the right to explore for and remove crude oil and natural gas from the lands, with the lessee paying exploration and development costs, operating costs, abandonment costs and reclamation costs, subject to paying rentals, taxes and royalties. Interests in Agreements (excluding freehold agreements) are acquired from the federal or provincial governments through competitive bidding or by undertaking work commitments, or by joint venture agreements with industry companies.

	Undeveloped Acres	
	Gross Acres(1)	Net Acres(1)
	(Thousands)	
Canada		
Western provinces	531	472
International(2)	1,205	698
Total Undeveloped Landholdings	1,736	1,170

Notes:

(1) "Gross Acres" means all of the acres in which Suncor has either an entire or undivided percentage interest in. "Net Acres" represents the acres remaining after deducting the undivided percentage interests of others from the gross acres.

(2) International includes undeveloped land holdings in the United States where coal bed methane exploration activities are currently being undertaken and in Australia, where previous coal bed methane activities were conducted. Subsequent to the end of 2002, Suncor sold

its interest in the Australian acreage, reducing international undeveloped landholdings by 675 thousand gross acres (338 thousand net acres).

Drilling

The following table sets forth the gross and net exploratory and development wells in Western Canada, the United States and Australia, which were completed, capped or abandoned in which Suncor's NG business unit participated during the years indicated.

	Year ended December 31,			
	2002		2001	
	Gross	Net	Gross	Net
Exploratory Wells				
Crude oil	—	—	—	—
Gas	7	2	5	4
Dry (1)	22	19	22	16
Total Exploratory Wells	29	21	27	20
Development Wells				
Crude oil	—	—	1	—
Gas	32	18	24	16
Dry	6	4	4	2
Total Development Wells	38	22	29	18
Total	67	43	56	38

Note:

(1) Includes 16 gross (15 net) coal bed methane wells in 2002 and 18 gross (14 net) coal bed methane wells in 2001.

Not included are earning wells completed by other companies under farm-out agreements relating to lands in which Suncor has an undivided percentage interest, since Suncor did not incur cash expenditures in connection with such wells. In addition to the above wells, Suncor had interests in 28 gross (17 net) exploratory wells in progress and 7 gross (3 net) development wells in progress at the end of 2002.

Suncor continues to hold interests in frontier properties (Arctic and Northwest Territories) including 28 long-term "significant discovery licences".

Wells

The following table summarizes the wells in which the NG business unit has a working interest or a royalty interest as at December 31, 2002.

	Producing Wells(1)(2)		Non-Producing Wells(1)(3)	
	Gross	Net	Gross	Net
Conventional Crude Oil Wells				
Alberta	44	29	39	18
British Columbia	22	10	1	1
Total Conventional Crude Oil Wells	66	39	40	19
Conventional Natural Gas Wells				
Alberta	310	173	34	17
British Columbia	51	23	11	7
Total Conventional Natural Gas Wells	361	196	45	24
Total Wells	427	235	85	43

Notes:

(1) Gross wells represent the number of wells in which NG has an undivided percentage interest and net wells represent NG's aggregate undivided percentage interest share in such wells.

(2) Producing wells are wells producing hydrocarbons or having the potential to produce, excluding shut-in wells. As at December 31, 2002 Suncor has interests in five oil fields and 29 gas fields.

(3) Non-Producing Wells represent management's estimate of shut-in wells that could be capable of economic production but were not in production as at December 31, 2002.

Sales and Sales Revenues

The following table shows the breakdown of NG's sources of revenues.

Gross Revenues(1)	Year ended December 31,	
	2002	2001
	($ millions)	
Crude oil and natural gas liquids	43	45
Natural gas	255	394
Pipeline	4	5
Other	13	14
Total	315	458

Note:

(1) Includes intersegment revenues.

Production Costs

The following table shows production (lifting) costs in connection with NG's crude oil and natural gas operations.

Production (Lifting) Costs	Year ended December 31,	
	2002	2001
	($ per BOE of gross production)	
Average production (lifting) cost of conventional crude oil and gas(1)	3.15	2.96

Note:

(1) Production (lifting) costs include all expenses related to the operation and maintenance of producing or producible wells and related facilities, natural gas plants and gathering systems. It does not include an estimate for future reclamation costs.

Quarterly Volumes and Netback Analysis

The following table shows Suncor's average production volumes, pricing, royalties, operating expenses and netbacks for natural gas, conventional crude oil and natural gas liquids, for the periods indicated.

	2002					2001				
	4Q	3Q	2Q	1Q	2002	4Q	3Q	2Q	1Q	2001
Natural Gas										
Production Volume (mmcf/day)	182	181	179	175	179	180	176	177	177	177
Price ($/mcf)	4.91	3.56	3.92	3.21	3.91	3.10	3.90	6.78	10.73	6.09
Royalties ($/mcf)	(1.62)	(0.81)	(0.96)	(0.63)	(1.01)	(0.54)	(0.85)	(1.58)	(2.91)	(1.46)
Operating Expenses ($/mcf)(1)	(0.88)	(0.96)	(0.89)	(0.93)	(0.91)	(0.97)	(0.79)	(0.95)	(0.73)	(0.86)
Netback ($/mcf)	2.41	1.79	2.07	1.65	1.99	1.59	2.26	4.25	7.09	3.77
Conventional Crude Oil										
Production Volume (kbbls/d)(2)	1.5	1.3	1.7	1.4	1.5	1.3	1.5	1.5	1.7	1.5
Price ($/bbl)	33.20	33.57	30.99	29.15	31.72	27.17	33.17	36.75	37.35	33.92
Royalties ($/ bbl)	(8.94)	(9.02)	(7.76)	(6.46)	(8.05)	(1.84)	(2.46)	(2.60)	(2.89)	(2.45)
Operating Expenses ($/ bbl)(1)	(5.34)	(6.26)	(4.72)	(5.79)	(5.48)	(7.25)	(4.76)	(5.69)	(3.85)	(5.17)
Netback ($/bbl)	18.92	18.29	18.51	16.90	18.19	18.08	25.95	28.46	30.61	26.30
Natural Gas Liquids										
Production Volume (kbbls/d)(2)	2.4	2.3	2.5	2.5	2.4	2.4	2.4	2.3	2.3	2.4
Price ($/bbl)	35.14	31.66	28.25	22.53	29.35	23.47	30.26	39.32	45.07	34.38
Royalties ($/ bbl)	(11.13)	(9.94)	(7.67)	(5.10)	(8.44)	(5.96)	(10.26)	(10.77)	(12.86)	(9.93)
Operating Expenses ($/ bbl)(1)	(5.42)	(5.98)	(5.25)	(5.30)	(5.48)	(5.83)	(4.75)	(5.72)	(4.40)	(5.17)

Netback ($/bbl)	18.59	15.74	15.33	12.13	15.43	11.68	15.25	22.83	27.81	19.28

Notes:

(1) Operating expenses includes production (lifting) costs and administrative expenses.

(2) Thousands of barrels per day.

Marketing, Pipeline and Other Operations

Suncor operates natural gas processing plants at South Rosevear, Pine Creek, Boundary Lake South, Progress and Simonette with a total design capacity of approximately 206 mmcf/day. Suncor's capacity interest in these gas processing plants is approximately 128 mmcf/day. Suncor also has varying undivided percentage interests in natural gas processing plants operated by other companies.

Approximately 69% of Suncor's natural gas production is marketed under direct sales arrangements to customers in Alberta, British Columbia, eastern Canada, and the United States. Contracts for these direct sales arrangements are of varied terms, with a majority having terms of one year or less, 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. Under these contracts, Suncor is responsible for transportation arrangements to the point of sale. Sales to the United States are made under a variety of arrangements with different transportation and pricing terms. NG's direct sales arrangements include some of the natural gas consumed in Suncor's Oil Sands plant at Fort McMurray and in the Company's downstream operations.

Approximately 31% of Suncor's natural gas production is sold under existing contracts to aggregators ("system sales"). Proceeds received by producers under these sales arrangements are determined on a netback basis, whereby each producer receives revenue equal to its proportionate share of sales less regulated transportation charges and a marketing fee. Most of NG's system sales volumes are contracted to TransCanada Gas Services and Pan-Alberta Gas Ltd. These companies resell this natural gas primarily to eastern Canadian and midwest and eastern United States markets.

To ensure ongoing direct sales access to markets in the United States, NG has entered into long-term gas pipeline transportation contracts. Suncor currently has 14 mmcf/day of firm capacity on the Northern Border Pipeline to the U.S. midwest that expires October 31, 2003. Suncor also has firm capacity of 40 mmcf/day on the Pacific Gas Transmission ("PGT") pipeline to the California border extending to the year 2023.

NG's conventional 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. Sales are generally made under spot contracts or under contracts that are terminable on relatively short notice. Suncor's conventional crude oil production is shipped on pipelines operated by independent pipeline companies. The NG business currently has no pipeline commitments related to the shipment of crude oil.

The Suncor-owned and operated Albersun pipeline was constructed in 1968 to transport natural gas to the Oil Sands plant. It extends approximately 300 kilometres south of the plant and connects with the TCPL Alberta intra-provincial pipeline system. The Albersun pipeline has the capacity to move in excess of 100 mmcf/day of natural gas. Suncor arranges for natural gas supply and controls most of the natural gas on the system under delivery based contracts. The pipeline moves natural gas both north and south for Suncor and other shippers. In 2002, throughput on the Albersun pipeline was 70 mmcf/day and revenues were approximately $4 million.

Competitive Conditions

Competitive conditions affecting Suncor's Natural Gas business are described under the heading "Competition" in the "Risk/Success Factors" section of this Annual Information Form.

Capital and Exploration Expenditures

The following table sets out, for the quarters indicated, capital expenditures by Suncor's NG business unit:

	2002				2001			
($ millions)	**4Q**	**3Q**	**2Q**	**1Q**	**4Q**	**3Q**	**2Q**	**1Q**
Property acquisition	2	-	-	-	—	-	—	—
Exploration	14	10	9	14	29	4	14	3
Development	18	22	31	43	19	20	17	26

NG expects to spend $160 million in 2003 to support the Company's goal of increasing natural gas production.

Environmental Compliance

For a description of the impact of environmental protection requirements on NG, refer to "Environmental Regulation and Risk" and "Government Regulation" in the "Risk/Success Factors" section of this Annual Information Form, and "Reclamation and Environmental Remediation Cost" under "Critical Accounting Policies" in the "Suncor Overview and Strategic Priorities" section of MD&A..

ENERGY MARKETING & REFINING

Suncor's EM&R business unit operates a refining and marketing business in Central Canada. Its refinery in Sarnia, Ontario, refines petroleum feedstock from Oil Sands and other sources into gasoline, distillates, and petrochemicals with the majority of them being distributed in its primary market of Ontario.

Approximately 62% of EM&R's petroleum products sales in 2002 (2001 — 59%) was sold through a distribution network in Ontario that sells gasoline and diesel to retail customers. Approximately 33% (2001 — 38%) was sold to industrial, commercial, wholesale and refining customers in Ontario and Quebec, representing primarily jet fuels, diesel and gasoline. The remaining 5% (2001 — 3%) represents petrochemical sales to the United States and Europe through Sun Petrochemicals Company, a 50% joint venture between a Suncor subsidiary and a U.S. company.

Beginning in 2001, EM&R's financial reporting is based on its Rack Back / Rack Forward organizational structure. The Rack-Back division procures and refines crude oil and feedstocks, and sells and distributes refined products to the Sarnia refinery's largest industrial and reseller customers. The Rack-Forward division is comprised of retail operations, retail natural gas marketing (which was sold in the second quarter of 2002), cardlock and industrial / commercial sales, and the UPI Inc. ("UPI") and Pioneer joint venture businesses. UPI is a joint venture company owned 50% by each of EM&R and GROWMARK Inc., a U.S. Midwest agricultural supply and grain marketing cooperative. Pioneer is a 50% joint venture partnership between Suncor and The Pioneer Group Inc.

Procurement of Feedstocks

EM&R's refining operation uses both synthetic and conventional crude oil. Its Sarnia Refinery procured approximately 58% (2001 — 47%) of its synthetic crude oil feedstock from Suncor's Oil Sands production in 2002. In 2002, 65% (2001 — 55%) of the crude oil refined at the Sarnia Refinery was synthetic crude oil. The balance of the refinery's synthetic crude oil, as well as its conventional and condensate feedstocks, were purchased from others under month to month contracts. In the event of a significant disruption in the supply of synthetic crude oil, the refinery has the flexibility to substitute other sources of sweet or sour conventional crude oil.

Suncor procures conventional crude oil feedstock for its refinery primarily from western Canada, supplemented from time to time with crude oil from the United States and other countries. Foreign crude oil is delivered to Sarnia via pipeline from the United States Gulf Coast or via the Interprovincial Pipeline from Montreal. Suncor has not made any firm commitments for capacity on these pipeline systems. Crude oil is procured from the market on a spot basis or under contracts terminable on short notice.

In 1998, EM&R signed a 10-year synergistic feedstock agreement with a Sarnia-based petrochemical refinery, Nova Chemicals (Canada) Ltd. Under this buy/sell agreement, EM&R obtains feedstock that is more suitable for production of transportation fuels in exchange for feedstock more suitable for petrochemical cracking. EM&R also enters into reciprocal buy/sell or exchange arrangements with other refining companies from time to time as a means to minimize transportation costs, balance product availability and enhance refinery utilization. EM&R also purchases refined products in order to meet customer requirements.

Refining Operations

The Sarnia Refinery produces transportation fuels (gasoline, diesel, propane and jet fuel), heating fuels, liquefied petroleum gases, residual fuel oil, asphalt feedstock, benzene, toluene, mixed xylenes and orthoxylene, as well as the petrochemicals A-100 and A-150 that are used in the manufacture of paint and chemicals.

The refinery has the capacity to refine 70,000 barrels of crude oil per day. Refining sales in 2002 averaged approximately 91,100 barrels per day (2001 — 93,400). The Sarnia Refinery is configured to allow for operational flexibility. In addition to conventional sweet and sour crudes, the refinery is capable of processing sweet synthetic crude oil, which yields a more valuable product mix. A hydrocracker, jet fuel tower and low-sulphur diesel tower further increase the refinery's ability to produce premium-value transportation fuels, distillates and naphtha, and its flexibility to vary the gasoline/distillate ratio. The hydrocracker has a capacity to process approximately 23,300 barrels per day. Additional flexibility in gasoline, octane and petrochemical production is provided by the complementary operations of an alkylation unit with a capacity of 5,400 barrels per day. The petrochemical facilities have a capacity of 13,100 barrels per day and produce benzene, toluene, mixed xylenes, orthoxylene and A-100 and A-150.

The refinery has a cracking capacity of 40,200 barrels per day from a Houdry catalytic cracker ("catcracker") and a hydrocracker. Approximately 40% of the cracking capacity is attributable to the catcracker, which uses older cracking technology.

In 2002, EM&R completed a planned maintenance shutdown on a portion of the refinery, involving a crude unit, vacuum unit, BTX unit, reformer unit, and pretreater unit. However, the refinery also experienced unplanned outages involving the hydrogen plant, the hydrocracker, and the catalytic cracker. Following the planned and unplanned maintenance work, the refinery operated with improved utilization rates in the last two quarters of the year.

Overall, crude utilization averaged 95% for the year, compared with 92% in 2001. The following chart sets out daily crude input, average refinery utilization rates, and cracking capacity utilization of the Sarnia Refinery over the last two years.

Sarnia Refinery Capacity	2002	2001
Average daily crude input (barrels per day)	66,400	64,200
Average crude utilization rate (%)(1)	95	92
Average cracking capacity utilization (%)(2)	91	88

Notes:

(1) Based on crude unit capacity and input to crude units.

(2) Based on cracking capacity and input to the hydrocracker and catalytic cracker.

The refinery's steam and electricity needs are currently being met by supply from the Sarnia Regional Co-generation Project. For more details, see the EM&R section under "Three Year Highlights" in this Annual Information Form.

Principal Products

Sales of gasolines and other transportation fuels represented 82% of EM&R's consolidated operating revenues in 2002 compared to 80% in 2001. Set forth below is information on daily sales volumes and percentage of EM&R's consolidated operating revenues contributed by product group for the last two years.

Product:	2002		2001	
	(thousands of cubic meters per day)	(% of EM&R's consolidated revenues)	(thousands of cubic meters per day)	(% of EM&R's consolidated revenues)
Transportation Fuels				
Gasoline				
Retail	4.5	35	4.3	31
Joint Ventures	3.2	19	3.1	17
Other	1.2	11	1.3	11
Jet Fuel	0.4	2	0.7	4
Diesel	2.9	15	3.1	17
Sub-total — Transportation Fuels	12.2	82	12.5	80
Petrochemicals	0.6	5	0.5	4
Heating Fuels	0.4	4	0.4	2
Heavy Fuel Oils	0.6	1	0.8	2
Other	0.7	2	0.6	2
Total Refined Products	14.5	94	14.8	90
Other Non-Refined Products(1)	—	6	—	10
Total%	—	100	—	100

Note:

(1) Includes ancillary revenues including non-fuel retail sales.

Principal Markets

Approximately 62 % (2001 — 59%) of EM&R's total sales volumes are marketed through retail networks, including the EM&R Sunoco-branded retail network, joint-venture operated retail stations and cardlock operations. This network is comprised of:

- 287 (2001 — 302) Sunoco-branded retail service stations
- 148 (2001 — 154) Pioneer-operated retail service stations
- 50 (2001 — 47) UPI-operated service stations and a network of 15 bulk distribution facilities for rural and farm fuels
- 18 (2001 — 18) Sunoco branded Fleet Fuel Cardlock sites

Refined petroleum products (excluding petrochemicals) are marketed under several brands, including the Company's Canadian "Sunoco" trademark. EM&R's other principal trademarks include "Ultra 94" in respect of its premium high octane gasoline, and "Gold Diesel" used in respect of its premium low sulphur diesel product.

Approximately 33% (2001 — 38%) of EM&R's total sales volumes are sold to industrial, commercial, wholesale, and refining customers, primarily in Ontario. EM&R also supplies industrial and commercial customers in Quebec through long-term arrangements with other regional refiners, or through Group Petrolier Norcan Inc., a 25% EM&R-owned fuels terminal and product supply business in Montreal.

EM&R markets toluene, mixed xylenes, orthoxylene and petrochemicals, primarily in Canada and the U.S., through Sun Petrochemicals Company. Suncor Energy Marketing Inc. has a 50% interest in Sun Petrochemicals Company, a petrochemical marketing joint venture that markets products from EM&R's Sarnia Refinery and from a Toledo, Ohio, refinery owned by the joint venture partner. Sun Petrochemicals Company markets petrochemicals used to manufacture plastics, rubber, synthetic fibres, industrial solvents and agricultural products, and as gasoline octane enhancers. All benzene production is sold directly to other petrochemical manufacturers in Sarnia.

EM&R's share of total refined product sales in its primary market of Ontario was approximately 17% in 2002 (2001 — 18%), reduced by 1% from 2001 due mainly to reduced distillate sales that resulted from the non-renewal of jet fuel contracts. Transportation fuels accounted for over 83% of EM&R's total sales volumes in 2002 (2001 — 84%); petrochemicals accounted for 5 % (2001 — 3%). The remaining volumes included other refined products such as heating fuels, heavy oils and liquefied petroleum gases, and were sold to industrial users and resellers.

EM&R supplies refined petroleum products to the Pioneer and UPI joint ventures. The Pioneer supply agreement expires in the fourth quarter of 2003, and thereafter will be automatically renewed for one-year terms unless terminated upon 12 months' prior written notice. No notice has been

given or received.

The UPI supply agreement expired in the second quarter of 2002, and was renewed for a perpetual term subject to the right of either party to terminate the agreement on 120 days prior written notice to the other. The shareholder agreement governing the operation of the joint venture provides that UPI Inc. cannot unilaterally terminate the agreement as long as Suncor remains a shareholder.

Transportation and Distribution

EM&R uses a variety of transportation modes to deliver products to market, including pipeline, water, rail and road. EM&R owns and operates petroleum transportation, terminal and dock facilities, including storage facilities and bulk distribution plants in Ontario. The major mode of transporting gasoline, diesel, jet fuel and heating fuels from the Sarnia Refinery to core markets in Ontario is the Sun-Canadian Pipe Line, which is 55% owned by Suncor and 45% owned by another refiner. The pipeline operates as a private facility for its owners. It serves terminal facilities in Toronto, Hamilton and London, and has a capacity of 126,000 barrels per day (20,000 cubic metres). EM&R utilized 53% of this capacity in 2002. Total utilization of the pipeline was 83% in 2002.

EM&R also has direct pipeline access to petroleum markets in the Great Lakes region of the United States by way of connection to a pipeline system in Sarnia operated by a U.S.-based refiner. This link to the U.S. allows EM&R to move products to market or obtain feedstocks/products when market conditions are favourable in the Michigan and Ohio markets.

EM&R believes that its own storage facilities, and those under long-term contractual arrangements with other parties, are sufficient to meet its current and foreseeable needs.

Competitive Conditions

Competitive conditions affecting Suncor's EM&R business are described under the heading "Competition" in the "Risk/Success Factors" section of this Annual Information Form.

Capital Expenditures

EM&R plans to spend approximately $145 million in 2003 compared with $78 million in 2002. The bulk of the 2003 spending will be allocated towards projects at Suncor's Sarnia Refinery designed to meet pending gasoline and distillate desulphurization initiatives, and to integrate production streams from Suncor's oil sands facility. Increased funds will also be available for investment in the Sunoco retail network. See "Risk/Success Factors Affecting Performance" in the EM&R section of MD&A and "Environmental Regulation and Risk" in the "Risk/Success Factors" section of this Annual Information Form.

Environmental Compliance

For a description of the impact of environmental protection requirements on EM&R, please refer to the sections entitled "Outlook" and "Risk/Success Factors Affecting Performance" in the EM&R section of MD&A. Also refer to "Environmental Regulation and Risk" and "Governmental Regulation" in the "Risk/Success Factors" section and the EM&R "Three Year History" section, of this Annual Information Form, and "Reclamation and Environmental Remediation Cost" under "Critical Accounting Policies" in the "Suncor Overview and Strategic Priorities" section of MD&A.

SUNCOR EMPLOYEES

The following table shows the distribution of employees among Suncor's three business units and its corporate office for the past two years.

	as at December 31,	
	2002	2001
Oil Sands	2,459	2,367
Natural Gas	191	190
Energy Marketing & Refining(1)	576	561
Corporate	196	189
Total(3)	3,422	3,307

Notes:

(1) Excludes joint venture employees.

(2) Reflects inclusion of Calgary-based employees providing technical support to the Firebag Project.

(3) In addition to Suncor employees, independent contractors supply a range of services to the Company.

The Communications, Energy and Paperworkers Union Local 707 represents approximately 1,500 Oil Sands employees. Suncor entered into a three-year collective agreement with the union effective May 1, 2001. Management believes Suncor's positive working relationship with the union will continue.

Employee associations represent approximately 171 of EM&R's Sarnia refinery and Sun-Canadian Pipe Line Company employees. In March 2002, a three-year agreement was signed with the Sarnia employee association that will be renegotiated in 2005. The agreement with the employee association of Sun-Canadian Pipe Line Company was signed in 1993, and it is renewed automatically each year unless terminated by

written notice by either party at least 60 days prior to the anniversary date of the agreement. No notice under such agreement has been received or given to date. Management believes Suncor's positive working relationship with this association will continue and the agreement will be automatically renewed on its anniversary. The employees at EM&R's London Terminal are currently

negotiating their first collective bargaining agreement. Currently there are 11 eligible employees for membership with Local #27 of the Canadian AutoWorkers (CAW), a private sector union in Canada.

RISK/SUCCESS FACTORS

Volatility of Crude Oil and Natural Gas Prices . Suncor's future financial performance is closely linked to oil prices, and to a lesser extent natural gas prices. The price of these commodities can be influenced by global and regional supply and demand factors. Worldwide economic growth, political developments, compliance or non-compliance with quotas imposed upon members of the Organization of Petroleum Exporting Countries and weather, among other things, can affect world oil supply and demand. Natural gas prices realized by Suncor are affected primarily by North American supply and demand and by prices of alternate sources of energy. All of these factors are beyond Suncor's control and can result in a high degree of price volatility not only in crude oil and natural gas prices, but also fluctuating price differentials between heavy and light grades of crude oil, which can impact prices for sour crude oil. In 2002, the heavy-light differential narrowed and improved Suncor's earnings. Management believes the differential will widen in 2003 from 2002 levels due to increased supply in the Canadian market and crude oil pricing. Oil and natural gas prices have fluctuated widely in recent years and Suncor expects continued volatility and uncertainty in crude oil and natural gas prices. A prolonged period of low crude oil prices could affect the value of Suncor's crude oil and gas properties and the level of spending on growth projects, and could result in curtailment of production at some properties. Accordingly, low crude oil prices could have an adverse impact on Suncor's financial condition and liquidity and results of operations.

Suncor cannot control the factors that influence supply and demand for, or the prices of, crude oil or natural gas. However, the Company has a hedging program that periodically fixes the price or a range of prices for its crude oil, natural gas, and the associated Canada/U.S. dollar exchange rate for a percentage of Suncor's total production volume. Suncor's objective is to manage exposure to market volatility and lend more certainty to the Company's ability to finance growth. If an operational upset occurred that reduced or eliminated crude oil and/or natural gas production for a period of time, Suncor would be required to continue to make payments under its hedging program if the actual price was higher than the hedged price. In addition, Suncor's hedging program is subject to many of the risks described under the heading, "Risks Associated with Energy Trading Activities", below. For particulars of Suncor's hedging position as of year-end 2002, see Note 5 of Suncor's 2002 Consolidated Financial Statements, which note is incorporated by reference herein.

Suncor conducts an assessment of the carrying value of its assets to the extent required by Canadian generally accepted accounting principles. If crude oil and natural gas prices decline, the carrying value of Suncor's assets could be subject to downward revisions, and Suncor's earnings could be adversely affected.

Volatility of Downstream Margins. EM&R operations are sensitive to wholesale and retail margins for its refined products, including gasoline. Margin volatility is influenced by overall marketplace competitiveness, weather, the cost of crude oil (see "Volatility of Crude Oil and Natural Gas Prices") and fluctuations in supply and demand for refined products. EM&R expects that margin and price volatility and overall marketplace competitiveness, including the potential for new market entrants, will continue.

Risk Factors Related to Firebag and Voyageur Projects. There are certain risks associated with the execution of the proposed Firebag Project and Voyageur, including: regulatory approvals, risks relating to schedule, resources and costs, including the availability and cost of materials, equipment and qualified personnel; the impact of general economic, business and market conditions; the impact of weather conditions; Suncor's ability to finance growth if commodity prices were to stay at low levels for an extended period; the impact of new entrants to the oil sands business which could take the form of competition for skilled people, increased demands on the Fort McMurray, Alberta infrastructure (for example, housing, roads and schools) and price competition for products sold into the marketplace; the potential ceiling on the demand for synthetic crude oil; and the effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment. The

commissioning and integration of new facilities with the existing asset base could cause delays in achieving targeted production capacity. Suncor management believes the planned increases in Oil Sands production through these projects present issues that require prudent risk management.

Risks Associated with In-Situ Extraction. Current steam-assisted gravity drainage (SAGD) technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam which is used in the recovery process. The amount of steam required in the production process can also vary and impact costs. The performance of the reservoir can also impact the timing and levels of production using this technology. Suncor has been advised by GLJ that in 2002, a number of operational commercial SAGD projects were in service, although no such projects have been operational for any extended period of time. Commercial application of this technology is not yet commonplace.

Increased Dependence on Oil Sands business. The Company's significant capital commitment to further its growth projects at Oil Sands, including the Firebag Project, and Voyageur if approved, may require Suncor to forego investment opportunities in other segments of its operations. The completion of future projects to increase production at Oil Sands will further increase the Company's dependence on the Oil Sands segment of its business. For example, in 2002, the Oil Sands business accounted for approximately 86% (79% in 2001) of Suncor's upstream production, 89% (59% in 2001) of Suncor's net earnings and 85% (52% in 2001) of Suncor's cash flow provided from operations.

Interdependence of Oil Sands Systems. The Oil Sands plant is susceptible to loss of production due to the interdependence of its component systems. For example, over the past four years, there have been a total of four outages, some of which were unplanned, of the 5C9 fractionator, an upgrading unit that separates hydrocarbon vapours into naphtha, kerosene and gas oil. These outages resulted in lost production of approximately 1.8 million barrels in each of 1999 and 2001, and approximately 0.8 million barrels in 2002. In 2003, Suncor plans to complete an $80 million project to replace the 5C9 fractionator with a larger unit that is expected to increase throughput, improve product quality and enhance reliability.

Through expansion projects like Millennium, Suncor expects to mitigate adverse impacts of its interdependent systems and to reduce the production and cash flow impacts of complete plant-wide shutdowns. For example, Millennium added a second complete processing operation, which provides Suncor with the flexibility to conduct periodic plant maintenance on one operation while continuing to generate production and cash flow from the other.

Competition. The petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of crude oil and natural gas interests, and the refining, distribution and marketing of petroleum products and chemicals. Suncor competes in virtually every aspect of its business with other energy companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers. Suncor believes that the competition for its custom blended synthetic crude oil production is other Canadian conventional and synthetic sweet and sour crude oil.

A number of other companies have entered or have indicated they are planning to enter the oil sands business and begin production of bitumen and synthetic crude oil, or expand existing operations. Recently some projects have been deferred. It is difficult to assess the number, level of production and ultimate timing of all of the potential new producers or where existing producers may increase production levels. Based on management's knowledge of other projects derived from publicly available information, Canada's production of bitumen and upgraded synthetic crude oil could increase to almost two million barrels (300,000 cubic metres) per day by the end of the decade. The trend toward industry consolidation has created more competitors with financial capacity who may enter into similar and competing oil sands businesses. The expansion of existing operations and development of new projects could materially increase the supply of bitumen and synthetic crude oil and other competing crude oil products in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices.

In the western Canadian diesel market demand and supply can fluctuate. Currently there is excess supply of diesel fuel which has resulted in reduced margins. Margins for diesel are typically higher than the margins for synthetic and conventional crude oil. The above noted expansion plans of Suncor's competitors could also result in an increase in the supply of diesel and further weakening of margins.

Historically, the industry-wide oversupply of refined petroleum products and the overabundance of retail outlets have kept pressure on downstream margins. Management expects that fluctuations in demand for refined products, margin volatility and overall marketplace competitiveness will continue. In addition, to the extent that Suncor's downstream business unit, EM&R, participates in new product markets, it could be exposed to margin risk and volatility from either cost and/or selling price fluctuations.

Need to Replace Conventional Natural Gas Reserves. The future natural gas reserves and production of the Company's NG business unit and, therefore, both Suncor's cash flow from such production and Suncor's ability to maintain a price hedge against growing consumption of natural gas in its Oil Sands and EM&R operations, are highly dependent on its success in discovering or acquiring additional reserves and exploiting its current reserve base. Without natural gas reserve additions through exploration and development or acquisition activities, Suncor's conventional natural gas reserves and production will decline over time as reserves are depleted. For example, in 2002, Suncor's average natural gas reservoir decline rates were in the 25% range (2001 — 28%), consistent with industry experience. Decline rates will vary with the nature of the reservoir, life-cycle of the well, and other factors. Therefore past decline rates are not necessarily indicative of future performance. Exploring for, developing and acquiring reserves is highly capital intensive. To the extent cash flow from operations is insufficient to generate sufficient capital and external sources of capital become limited or unavailable, Suncor's ability to make the necessary capital investments to maintain and expand its conventional natural gas reserves could be impaired. In addition, the long term performance of Suncor's NG business is dependent on its ability to consistently and competitively find and develop low cost, high-quality reserves that can be economically brought on stream. Market demand for land and services can also increase or decrease finding and development costs. There can be no assurance that Suncor will be able to find and develop or acquire additional reserves to replace production at acceptable costs.

Risks Related to Coal Bed Methane. Coal Bed Methane (CBM) exploration is being undertaken by Suncor in Canada, and in the U.S. through a wholly owned subsidiary, Suncor Energy (Natural Gas) America Inc. The identification of gas in coals is necessary but not sufficient for establishing commercial success. Effective production technology, water handling, well productivity and surface access, a requirement for large land blocks, and a pilot production period are risk elements unique to CBM. Other producers' Canadian activities in CBM have progressed to the pilot test stage with several projects that have wells producing salable gas. Suncor views the ultimate viability and profitability of these plays as uncertain.

CBM is a commercial gas resource in the U.S. The risks associated with CBM activities in the U.S. vary by geographic region but can include: constraints on land access from federal, state and individual land holders; local opposition to well drilling and CBM development; high costs of treating water produced with CBM gas; limited regional pipeline exit capacity; and strong competition for mineral leases and services. The regulatory framework and stakeholder environment varies by region. The physical operation of drilling and ultimately producing gas in a location distant from Suncor's key management presents risks of inadequate oversight of operations. Business activity in the U.S. has different political risk than in Canada, and is conducted in an environment where litigation and legal risk are more prevalent and substantial.

Operating Hazards and Other Uncertainties. Each of Suncor's three principal business units, Oil Sands, NG and EM&R, require high levels of investment and have particular economic risks and opportunities. Generally, Suncor's operations are subject to hazards and risks such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts and oil spills, any of which can cause personal injury, damage to property, equipment and the environment, as well as interrupt operations. In addition, all of Suncor's operations are subject to all of the risks normally incident to the transportation, processing and storing of crude oil, natural gas and other related products.

At Oil Sands, mining oil sand, extracting bitumen from the oil sand, and upgrading bitumen into synthetic crude oil and other products, involve particular risks and uncertainties. Oil Sands is susceptible to loss of production, slowdowns, or restrictions on its ability to produce higher value products due to the interdependence of its component systems. Severe climatic conditions at Oil Sands can cause reduced production and in some situations result in higher costs. While there is virtually no finding cost associated with oil sands resources, the costs associated with production, including mine development and drilling of wells for SAGD operations, and the costs associated with upgrading bitumen into synthetic crude oil, can entail significant capital outlays. The costs associated with synthetic crude oil production at Oil Sands are largely fixed and, as a result, operating costs per unit are largely dependent on levels of production.

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the government of Canada, certain governmental entities and the Regional Municipality of Wood Buffalo (which includes the city of Fort McMurray, Alberta), claiming, among other things, a declaration that the plaintiffs have aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which Oil Sands and most of the other oil sands operations in Alberta are situated. To Suncor's knowledge the aboriginal peoples have made no claims against Suncor and Suncor is unable to assess the effect, if any, the claim would have on its Oil Sands operations.

In Suncor's NG business unit, the risks and uncertainties associated with the exploration for, and the development, production, transportation and storage of crude oil, natural gas and natural gas liquids should not be underestimated or viewed as predictable. NG's operations are subject to all of the risks normally incident to drilling for natural gas wells, the operation and development of such properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, adverse weather conditions, pollution, and other environmental risks.

Suncor's downstream business unit, EM&R, is subject to all of the risks normally incident to the operation of a refinery, terminals and other distribution facilities, as well as service stations, including loss of product or slowdowns due to equipment failures or other accidents.

Although Suncor maintains a risk management program, including an insurance component, such insurance may not provide adequate coverage in all circumstances, nor are all such risks insurable. Losses resulting from the occurrence of these risks could have a material adverse impact on Suncor. Refer to Note 9(b) to Suncor's 2002 Consolidated Financial Statements, which note is incorporated by reference herein, for further description of Suncor's insurance coverage.

In addition, there are risks associated with growth projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations. The success of projects incorporating new technologies, such as the Firebag Project, cannot be assured.

There are also inherent risks, including political and foreign exchange risk, in investing in business ventures internationally. Currently, Suncor does not have material international investments but it continues to assess downstream integration and coal bed methane opportunities in the United States. Export sales in 2002 represented 10% of Suncor's 2002 consolidated revenue (2001 — 14%).

Interest Rate Risk. Suncor is exposed to fluctuations in short-term Canadian interest rates as a result of the use of floating rate debt. Suncor maintains a substantial portion of its debt capacity in revolving, floating rate bank facilities and commercial paper, with the remainder issued in fixed rate borrowings. To minimize its exposure to interest rate fluctuations, Suncor occasionally enters into interest rate swap agreements and exchange contracts to either effectively fix the interest rate on floating rate debt or to float the interest rate on fixed rate debt. For more details, see the "Liquidity and Capital Resources" section of MD&A.

Exchange Rate Fluctuations. Suncor's 2002 Consolidated Financial Statements are presented in Canadian dollars. Results of operations are affected by the exchange rates between the Canadian dollar and the U.S. dollar. These exchange rates have varied substantially in the last five years. A substantial portion of Suncor's revenue is received by reference to U.S. dollar denominated prices, and a significant portion of Suncor's debt is denominated in U.S. dollars. Crude oil and natural gas prices are generally based in U.S. dollars, while Suncor's sales of refined products are primarily in Canadian dollars. Fluctuations in exchange rates between the U.S. and Canadian dollar may therefore give rise to foreign currency exposure, either favorable or unfavorable, creating another element of uncertainty. In the future, the strength of the Canadian dollar relative to foreign currencies could create additional uncertainties for Suncor.

Environmental Regulation and Risk. Environmental regulation affects nearly all aspects of Suncor's operations. These regulatory regimes are laws of general application that apply to Suncor in the same manner as they apply to other companies and enterprises in the energy industry. The regulatory regimes require Suncor to obtain operating licenses and permits in order to operate, and impose certain standards and controls on activities relating to mining, oil and gas exploration, development and production, and the refining, distribution and marketing of petroleum products and petrochemicals. Environmental assessments and regulatory approvals are required before initiating most new major projects or undertaking significant changes to existing operations. In addition to these specific, known requirements, Suncor expects future changes to environmental legislation, including anticipated legislation to implement Canada's ratification of the Kyoto Accord, will impose further requirements on companies operating in the energy industry. Some of the issues that are or may in future be subject to environmental regulation include the possible cumulative impacts of oil sands development in the Athabasca region; storage, treatment, and disposal of hazardous or industrial waste; the need to reduce or stabilize various emissions; issues relating to global climate change, land reclamation and restoration; Great Lakes water quality; and reformulated gasoline to support lower vehicle emissions. Changes in environmental regulation could have a potentially adverse effect on Suncor from the standpoint of product demand, product reformulation and quality, methods of production and distribution and costs. For example, requirements for cleaner-burning fuels could cause additional costs to be incurred, which may or may not be recoverable in the marketplace. The complexity and breadth of these issues make it extremely difficult to predict their future impact on Suncor. Management anticipates capital expenditures and operating expenses could increase in the future as a result of the implementation of new and increasingly stringent environmental regulations. Compliance with environmental regulation can require significant expenditures and failure to comply with

environmental regulation may result in the imposition of fines and penalties, liability for clean up costs and damages and the loss of important permits.

Suncor is required to and has posted annually with Alberta Environment an irrevocable letter of credit equal to $0.03 per bbl of crude oil produced ($16 million as at December 31, 2002) as security for the estimated cost of its reclamation activity on Leases 86 and 17, and the Steepbank Mine. For Project Millennium, Suncor has posted an irrevocable letter of credit equal to approximately $27 million, representing security for the estimated cost of reclamation activities relating to Project Millennium up to the end of December 2002. Subsequent to year end, the face amount of these letters of credit was increased to approximately $70 million in aggregate. For the Firebag Project, Suncor has posted an irrevocable letter of credit equal to approximately $5 million, representing security for the estimated cost of reclamation activities relating to the project up to the end of December 2002. For more information about Suncor's reclamation and environmental mediation obligations, refer to "Reclamation and Environmental Remediation Cost" under "Critical Accounting Policies" in the "Suncor Overview and Strategic Priorities" section of MD&A.

In 1999, the Canadian government passed legislation limiting sulphur levels in gasoline to an average of 150 parts per million (ppm) from mid-2002 to the end of 2004, and a maximum of 30 ppm thereafter. The Canadian refining industry faces significant capital spending to construct sulphur removal facilities to meet these requirements. In 2001 EM&R finalized an investment plan to meet those limits. Capital spending to achieve compliance is expected to be approximately $40 million, and will involve the addition of a new desulphurization unit. The project has been progressing on schedule and construction of the unit is expected to be completed in 2003.

In 2002, the Canadian government also passed legislation limiting the concentration of sulphur in diesel fuel produced or imported for use in on-road vehicles to a maximum of 500 ppm until May 31, 2006, and a maximum of 15 ppm thereafter. Capital spending required to achieve compliance is estimated at approximately $225 million.

Regulations reducing sulphur in off-road diesel and light fuel oil are also expected to take effect later in the decade. At this time it is not possible to assess the impact these expected regulations may have on EM&R. The ultimate cost to comply may vary as details of the regulations are announced. In addition, EM&R is evaluating several strategic options including the potential to enhance integration of the Sarnia Refinery with production from Oil Sands, and to possibly increase value through integration with the diesel desulphurization facilities.

Uncertainty of Reserve and Resource Estimates. The reserve data and resource estimates for Suncor's Oil Sands and NG business units, included in Suncor's Annual Information Form, represent estimates only. There are numerous uncertainties inherent in estimating quantities and quality of these proved and probable reserves and other resources, including many factors beyond the control of Suncor.

In general, estimates of economically recoverable reserves are based upon a number of variable factors and assumptions, such as historical production from the properties, the assumed effect of regulation by governmental agencies and future operating costs, all of which may vary considerably from actual results. The accuracy of any reserve estimate is a matter of engineering interpretation and judgment and is a function of the quality and quantity of available data, which may have been gathered over time. In the Oil Sands business unit, reserve estimates are based upon a geological assessment, including drilling and laboratory tests, and also consider current production capacity and upgrading yields, current mine plans, operating life and regulatory constraints. The Firebag reserves and resource estimates are based upon a geological assessment based upon the data gathered from evaluation drilling, the testing of core samples and seismic operations and demonstrated commercial success of the in-situ process. In the NG business unit, reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward. For these reasons, estimates of the economically recoverable reserves attributable to any particular group of properties, and in NG the classification of such reserves based on risk of recovery prepared by different engineers or by the same engineers at different times, may vary substantially. At Oil Sands, the independent audit of mining reserves does not take into account the economic aspects of future reserves. Suncor's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from such estimates, and such variances could be material.

Certain information included in this Annual Information Form to describe Suncor's reserves, such as "probable reserves", "proved plus probable reserves" and "resources" is presented in accordance with Canadian disclosure requirements, but would be prohibited in filings with the United States Securities and Exchange Commission by U.S. companies. The differences between Canadian and U.S. standards of reporting reserves and resources may make it difficult to compare Suncor's reserve information with the reserve information of companies subject to the U.S. standards of reporting. For additional supplementary disclosures relating to Suncor's oil and gas activities in accordance with Statement 69 of the U.S. Financial Accounting Standards Board, refer to the disclosures made pursuant to Exhibit 1 to Suncor's Form 40-F, filed with the U.S. Securities and Exchange Commission and also filed with Canadian securities regulatory authorities, which Exhibit is incorporated by reference herein.

Labour Relations. Suncor's hourly employees at its Oil Sands facility near Fort McMurray, its London terminal operation, its Sarnia refinery and Sun-Canadian Pipeline Company are represented by labour unions or employee associations. Any work interruptions involving Suncor's employees, or contract trades utilized in its growth projects, could materially and adversely affect Suncor's business and financial position.

Risk Associated with the Energy Trading Activities. The nature of trading activities creates exposure to financial risks. These include risks that movements in prices or values will result in a financial loss to the Company; a lack of counterparties will leave the Company unable to liquidate or offset a position, or

unable to do so at or near the previous market price; the Company will not receive funds or instruments from its counterparty at the expected time; the counterparty will fail to perform an obligation owed to the Company; the Company will suffer a loss as a result of human error or deficiency in its systems or controls; or that the Company will suffer a loss as a result of contracts being unenforceable or transactions being inadequately documented. A separate risk management function within Suncor directs and monitors practices and policies and provides independent verification and valuation of Suncor's trading and marketing activities.

Governmental Regulation. The oil and gas industry in Canada, including the oil sands industry and the downstream segment of the Company, operates under federal, provincial and municipal legislation. This industry is also subject to regulation and intervention by governments in such matters as land tenure, royalties, government fees, production rates, environmental protection controls, the reduction of greenhouse gas emissions, the export of crude oil, natural gas and other products, the awarding or acquisition of exploration and production, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and mine sites (including restrictions on production) and possibly expropriation or cancellation of contract rights. Before proceeding with most major projects, including significant changes to existing operations, Suncor must obtain regulatory approvals. The regulatory approval process can involve stakeholder consultation, environmental impact assessments and public hearings, among other things. In addition, regulatory approvals may be subject to conditions including security deposit obligations and other commitments. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays, abandonment or restructuring of projects and increased costs, all of which could negatively affect future earnings and cash flow. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas, increase Suncor's costs and have a material adverse affect on its financial condition.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

Selected Consolidated Financial Information

The following selected consolidated financial information for each of the years in the three-year period ended December 31, 2002 is derived from Suncor's 2002 Consolidated Financial Statements. Suncor's consolidated financial statements for each of the years in the three-year period ended December 31, 2002 have been audited by PricewaterhouseCoopers LLP, Chartered Accountants. The information set forth below should be read in conjunction with MD&A and Suncor's 2002 Consolidated Financial Statements.

	Year ended December 31,(1)		
	2002	2001	2000
	($ millions except per share amounts)		
Revenues	4,904	4,199	3,388
Net earnings	761	388	377
Per common share(1) (undiluted)	1.64	0.79	0.78
Per common share(1) (diluted)	1.61	0.78	0.77
Cash flow provided from operations	1,440	831	958
Per common share(1)	3.11	1.76	2.06
Capital and exploration expenditures	877	1,678	1,998

	Year ended December 31,(1)		
	2002	2001	2000
	($ millions except per share amounts)		
Total assets	8,683	8,094	6,833
Long-term debt(2)	2,686	3,113	2,193
Accrued liabilities and other(3)	226	251	252
Common shareholders' equity(4)	2,935	2,255	1,961

Notes:

(1) Per share amounts for all years reflect two-for-one share splits in 2002 and 2000, and dividend payments and foreign currency revaluation related to the Company's preferred securities.

(2) Includes current portion.

(3) See Note 6 to Suncor's 2002 Consolidated Financial Statements, which Notes are incorporated by reference herein.

(4) Excludes Preferred Securities issued in 1999. See Dividend Policy and Record.

The following table sets forth, for each of the two most recently completed financial years, the revenues for each category of Suncor's principal products or services that accounted for 15 per cent or more of Suncor's total consolidated revenues.

Revenues from	($ millions)	%	($ millions)	%
Transportation fuel sales	2,266	46	2,277	54
Crude oil sales	1,954	40	1,017	24
Other	682	14	900	22
Total	4,902(1)	100	4,194(1)	100

Note:

(1) Excludes interest income.

Dividend Policy and Record

Suncor's Board of Directors has established a policy of paying dividends on a quarterly basis. This policy is 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.

During 1999, the Company completed a Canadian offering of $276 million of 9.05% preferred securities and a U.S. offering of U.S.$162.5 million of 9.125% preferred securities, the proceeds of which totaled Canadian $507 million after issue costs of $17 million ($10 million after income tax credits of $7 million). The preferred securities are unsecured junior subordinated debt of the Company, due in 2048 and redeemable at the Company's option on or after March 15, 2004 for proceeds equal to the original principal amount of the preferred securities plus any accrued and unpaid interest as at the date of redemption. Subject to certain conditions, the Company has the right to defer payment of interest on the securities for up to 20 consecutive quarterly periods. Deferred interest and principal amounts are payable in cash, or, at the option of the Company, from the proceeds on the sale of equity securities of the Company delivered to the trustee of the preferred securities. For accounting purposes, the preferred securities are classified as share capital in the consolidated balance sheet and the interest distributions thereon, net of income taxes, are classified as dividends in the Company's 2002 Consolidated Financial

Statements, but generally treated as interest income to the recipient for Canadian or U.S. tax purposes.

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

	Year ended December 31,		
	2002	2001	2000
Common Shares cash dividends(1)	$ 0.17	$ 0.17	$ 0.17
Preferred securities cash interest distributions(1)(2)	$ 0.11	$ 0.11	$ 0.11
Dividends paid in common shares	—	—	—

Note:

(1) Per share amounts have been adjusted to reflect a two-for-one share split in 2002.

(2) Per share preferred securities cash interest distributions are calculated as total preferred securities dividends divided by the weighted average outstanding common shares in the year.

Future Commitments to Buy, Sell, Exchange or Transport Crude Oil And Natural Gas

In order to ensure continued availability of, and access to, transportation facilities for the crude oil and natural gas products of its Oil Sands and Natural Gas business units, the Company has entered into long-term contracts for pipeline capacity on various third party systems.

The Company's Oil Sands business unit has entered into a long-term commitment with Enbridge for the transportation of sour crude oil and bitumen from Suncor's oil sands plant near Ft. McMurray, Alberta, to Hardisty, Alberta. Particulars of that commitment are described under the heading "Operations" in the "Oil Sands" section of this Annual Information Form.

Natural gas product pipeline commitments are described in the following table:

Nature of Commitments	Term	Volume (mmcf/day)	Aggregate Price/Cost ($ Millions)	Price Per mcf
Natural gas pipeline commitments:				
Nova	1998-2008	**	25	$ 0.17
Westcoast Energy	2001-2006	27	7	$ 0.27
Foothills	1997-2003	16	1	$ 0.08
Northern Border	1997-2003	14	2	$ 0.48
Alberta Natural Gas	1991-2008	41	6	$ 0.07
Pacific Gas Transmission	1995-2023	40	130	$ 0.43

**volume varies on an annual basis.

The Company's Natural Gas business has entered into numerous natural gas purchase and sale commitments, aggregating 50 mmcf/day and 180 mmcf/day, respectively. Purchase commitments are for one year terms with variable pricing, representing index-based pricing. Sales commitments consist of both short- and long- term contracts ranging from one to five years in duration, with variable pricing generally based on a combination of fixed and index-based terms.

Oil Sands has also entered into long-term contracts to sell crude oil products to customers, some of which are described under the heading, "Sales of Synthetic Crude Oil and Diesel" in the "Oil Sands" section of this Annual Information Form. In addition, the Company periodically enters into crude oil and foreign

currency swap and option contracts to protect its future Canadian dollar earnings and cash flows from the potential adverse impact of low petroleum prices and an unfavourable U.S./Canadian dollar exchange rate. For further particulars of these hedging arrangements, see the information under the heading "Hedging", under "Risk/Success Factors Affecting Performance" in the "Suncor Overview and Strategic Priorities"

section of the Company's MD&A, and Note 5 to Suncor's 2002 Consolidated Financial Statements, which note is incorporated by reference herein.

Also see Note 9(a) to Suncor's 2002 Consolidated Financial Statements, which note is incorporated by reference herein, for a further description of the Company's operating commitments for 2003 and subsequent years.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Suncor's MD&A is incorporated by reference into and forms an integral part of this Annual Information Form, and should be read in conjunction with Suncor's 2002 Consolidated Financial Statements and the notes thereto.

MARKET FOR THE SECURITIES OF THE ISSUER

The common shares of Suncor are listed on The Toronto Stock Exchange in Canada, and on the New York Stock Exchange in the United States. To the best of management's knowledge, approximately 40% of Suncor's common shares are beneficially held by residents of the United States. Suncor's 9.05% preferred securities are listed on The Toronto Stock Exchange in Canada, and Suncor's 9.125% preferred securities are listed on the New York Stock Exchange in the United States.

DIRECTORS AND EXECUTIVE OFFICERS

Directors

Reference is made to the information under the heading, "Election of Directors" on pages 3 - 6 inclusive of Suncor's Management Proxy Circular dated February 27, 2003 for information regarding Suncor's directors, which information is incorporated by reference into this Annual Information Form.

Executive Officers

The following are the executive officers of the Corporation. Except where otherwise indicated, the persons named in the table below held the offices set out opposite their respective names as at December 31, 2002 and as of the date hereof.

Name and Municipality of Residence	Office(1)
RICHARD L. GEORGE Calgary, Alberta	President and Chief Executive Officer
M.M. (MIKE) ASHAR Fort McMurray, Alberta	Executive Vice President, Oil Sands
DAVID W. BYLER M.D. of Rockyview, Alberta	Executive Vice President, Natural Gas and Renewable Energy
STEVEN W. WILLIAMS Calgary, Alberta	Executive Vice President, Corporate Development and Chief Financial Officer

Name and Municipality of Residence	Office(1)
THOMAS L. RYLEY Toronto, Ontario	Executive Vice President, Energy Marketing and Refining
TERRENCE J. HOPWOOD Calgary, Alberta	Senior Vice President and General Counsel
SUE LEE Calgary, Alberta	Senior Vice President, Human Resources and Communications
KEVIN D. NABHOLZ Calgary, Alberta	Senior Vice President, Major Projects
J. KENNETH ALLEY Calgary, Alberta	Vice President, Finance

All of the foregoing executive officers of the Company have, for the past five years, been actively engaged as executives or employees of Suncor or its affiliates, except Mr. Williams, who joined the Company in May 2002. Prior to joining Suncor, Mr. Williams held various executive positions with Octel Corporation, a global chemicals company. Prior to joining Octel Corporation in 1995, Mr. Williams held executive positions with Esso Petroleum Company Limited, an affiliate of Exxon.

The percentage of Common Shares of Suncor owned beneficially, directly or indirectly, or over which control or direction is exercised by Suncor's directors and executive officers, as a group, is less than 1%.

Additional Disclosure for Directors and Executive Officers

To the best of our knowledge, having made due inquiry, Suncor confirms that, as at December 31, 2002:

(i) in the last ten years, no director or executive officer of Suncor is or has been a director or officer of another issuer that, while that person was acting in that capacity,

(a) was the subject of a cease trade or similar order, or an order that denied the other issuer access to any exemptions under Canadian securities legislation for a period of more than 30 consecutive days; or

(b) became bankrupt or made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangements or compromises with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than Mr. Canfield, a director of Suncor who was a director of Royal Trust Co. in 1994 when it entered into a plan of arrangement with creditors and Mr. Korthals, a director of Suncor who was a director of Anvil Range Mining Corporation, which sought protection under the Companies Creditors Arrangement Act (Canada) in 1998;

(ii) no director or executive officer of Suncor has

(a) been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with a Canadian securities regulatory authority; or

(b) has been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision;

(iii) no director or executive officer of Suncor nor any personal holding company controlled by such person has become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the director or executive officer; and

(iv) no director or executive officer has any direct or indirect material interest in respect of any matter that has materially affected or will materially affect Suncor or any of its subsidiaries.

ADDITIONAL INFORMATION

Copies of the documents set out below may be obtained by any person upon request to the Secretary of the Company at 112 - 4 Avenue S.W., Calgary, Alberta, T2P 2V5, by calling 1-800-558-9071, or by e-mail request to info@suncor.com.

(i) The current Suncor Annual Information Form together with any pertinent information incorporated by reference therein;

(ii) The current Suncor comparative financial statements for the most recently completed financial year and the report of the auditors relating thereon, together with any subsequent interim financial statements;

(iii) Suncor's management proxy circular in respect of its most recent annual meeting of shareholders that involved the election of directors; and

(iv) Any other documents incorporated by reference into Suncor's most recent preliminary short form prospectus or short form prospectus if securities of Suncor are in the course of distribution pursuant to such documents.

Copies of such documents will be made available without charge at any time when Suncor's securities are in the course of distribution pursuant to a short form prospectus. At any other time Suncor reserves the right to impose a reasonable charge for requests by persons other than security holders. Such documents are available electronically on Suncor's web site at www.suncor.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Suncor's securities, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in Suncor's most recent management proxy circular for its most recent annual meeting of its shareholders that involved the election of directors. Additional financial information is provided in Suncor's 2002 Consolidated Financial Statements.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

Suncor Energy Inc. (the "Registrant") undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the staff of the Securities and Exchange Commission ("SEC"), and to furnish promptly, when requested to do so by the SEC staff,

information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises, or transactions in said securities.

B. Consent to Service of Process

The Registrant has filed previously with the SEC a Form F-X in connection with the Common Shares.

CONTROLS AND PROCEDURES

A. Evaulation

Based on their evaluation as of a date within 90 days of the filing date of this report, Registrant's Chief Executive Officer and Chief Financial Officer had concluded that Registrant's disclosure controls and procedures as defined in Rule 13(a)-14(c) and 15(d)-14(c) under the Exchange Act are effective to ensure that, information required to be disclosed by the Registrant in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms.

B. Changes in Internal Controls

There were no significant changes in the Registrant's internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation, nor were there any significant deficiencies or material weaknesses in the Registrant's internal controls. As a result, no corrective actions were required or undertaken.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

SUNCOR ENERGY INC.

DATE: April 3, 2003

PER: "RICHARD L. GEORGE"
RICHARD L. GEORGE
President and Chief Executive Officer

CERTIFICATIONS

I, RICHARD L. GEORGE, President and Chief Executive Officer of Suncor Energy Inc. ("Registrant"), certify that:

1. I have reviewed this annual report on Form 40-F of the Registrant;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this annual report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Registrant and have:

   (a) designed such disclosure controls and procedures to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) evaluated the effectiveness of the Registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the Registrant's auditors and the

audit committee of Registrant's board of directors (and persons performing the equivalent function):

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect the Registrant's ability to record, process, summarize and report financial data and have identified for the Registrant's auditors any material weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal controls; and

6. The Registrant's other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

SUNCOR ENERGY INC.

DATE: April 3, 2003

PER: "RICHARD L. GEORGE"
RICHARD L. GEORGE
President and Chief Executive Officer

I, STEVEN W. WILLIAMS, Executive Vice President, Corporate Development and Chief Financial Officer of Suncor Energy Inc. ("Registrant"), certify that:

1. I have reviewed this annual report on Form 40-F of the Registrant;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this annual report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Registrant and have:

(a) designed such disclosure controls and procedures to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

(b) evaluated the effectiveness of the Registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

(c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the Registrant's auditors and the audit committee of Registrant's board of directors (and persons performing the equivalent function):

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect the Registrant's ability to record, process, summarize and report financial data and have identified for the Registrant's auditors any material weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal controls; and

6. The Registrant's other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

SUNCOR ENERGY INC.

DATE: April 3, 2003

PER: "STEVEN W. WILLIAMS"
STEVEN W. WILLIAMS
Executive Vice President,
Corporate Development and
Chief Financial Officer

EXHIBIT INDEX

Exhibit No.	Description
1	U.S. Oil and Gas Data
2	Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2002, including reconciliation to U.S. GAAP (Note 19)
3	Management's Discussion and Analysis for the fiscal year ended December 31, 2002, dated February 27, 2003
4	Excerpts from pages 2 to 6 inclusive of Suncor Energy Inc.'s Management Proxy Circular dated February 27, 2003
5	Consent of PricewaterhouseCoopers LLP
6	Consent of Gilbert Laustsen Jung Associates Ltd.
7	Certificate of the President and Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
8.	Certificate of the Executive Vice President, Corporate Development and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

EHIBIT 1

U.S. Oil and Gas Data

OIL AND GAS DATA

The following data is provided in accordance with the provisions of the Financial Accounting Standards Board's Statement No. 69 (Statement 69). This statement requires disclosure about conventional oil and gas activities only, and therefore the company's oil sands activities are excluded.

Proved Oil and Gas Reserves Quantities

	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, 1998	69	1 197	56	915
December 31, 1999	51	1 013	41	764
Revisions of previous estimates	(3)	(52)	(6)	(81)
Purchases of minerals in place	—	9	—	7
Extensions and discoveries	1	39	1	28
Production	(3)	(73)	(2)	(52)
Sales of minerals in place	(30)	(139)	(23)	(99)
December 31, 2000	16	797	11	567
Revisions of previous estimates	(1)	(3)	—	4
Extensions and discoveries	—	27	—	20
Production	(1)	(65)	(1)	(45)
Sales of minerals in place	—	(1)	—	(1)
December 31, 2001	14	755	10	545
Revisions of previous estimates	—	(35)	—	(18)
Extensions and discoveries	145	53	125	39
Production	(1)	(65)	(1)	(48)
Sales of minerals in place	—	(2)	—	(2)
December 31, 2002	**158**	**706**	**134**	**516**
Proved developed				
December 31, 1998	53	730	43	557
December 31, 1999	38	627	30	471
December 31, 2000	13	573	10	414
December 31, 2001	11	573	8	416
December 31, 2002	**11**	**584**	**8**	**426**

Proved reserves are considered recoverable under current technology and existing economic conditions, from reservoirs that are evaluated on known drilling, geological, geophysical and engineering data.

Proved developed reserves are on production, or reserves that could be recovered from existing wells or facilities, if the company placed them on production.

Gross reserves are presented before deducting royalties. Net reserves are after deducting royalties. Royalties can vary depending upon factors such as prices, production volumes, timing of initial production and changes in legislation.

All reserves are located in Canada. There has been no major discovery or other favourable or adverse event that caused a significant change in estimated proved reserves since December 31, 2002. The company has no long-term supply agreements or contracts with governments or authorities in which it acts as producer nor does it have any interest in oil and gas operations accounted for by the equity method.

Capitalized Costs Relating to Oil and Gas Producing Activities

	Capitalized costs relating to oil and gas activities for the years ended December 31,	
	2002	2001
	($ millions)	
Proved properties	1,723	931
Unproved properties	128	409
Other support facilities and equipment	16	14
Total cost	1,867	1,354
Accumulated depreciation and depletion	(532)	(488)
Net capitalized costs	1,335	866

Costs Incurred in Oil and Gas Acquisition, Exploration and Developmental Activities

	Costs incurred for the years ended December 31		
	2002	2001	2000
		($ millions)	
Property acquisition costs			
Proved properties	2	—	5
Unproved properties	12	5	7
Exploration costs	17	27	39
Development costs	510	256	144
Total capital and exploration expenditures	541	288	195

Results of Operations for Oil and Gas Production

	Results of Operations for Oil and Gas Production For the years ended December 31		
	2002	2001	2000
		($ millions)	
Revenues			
Sales to unaffiliated customers	200	286	139
Transfers to other operations	16	58	183
	216	344	322
Expenses			
Production costs	39	36	47
Depreciation, depletion and amortization	66	61	68
Exploration	27	31	63
Gain on disposal of assets	(4)	(8)	(147)
Restructuring costs	—	(2)	65
Other related costs	10	30	25
	138	148	121
Operating profit before income taxes	78	196	201
Related income taxes	(43)	(79)	(103)
Results of operations	35	117	98

Standardized Measure of Discounted Future Net Cash Flows from Estimated Production of Proved Oil and Gas Reserves after Income Taxes

In computing the standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves after income taxes, assumptions other than those mandated by Statement 69 could produce substantially different results. The Company cautions against viewing this information as a forecast of future economic conditions or revenues, and does not consider it to represent the fair market value of gas properties. Figures are based on year-end commodity prices, and are as follows:

	2002	2001	2000
Year end natural gas price assumptions (AECO— CDN$/GJ)	5.21	3.55	7.81
Year end crude oil price assumption (WTI US$/bbl)	29.40	19.40	28.40

Actual future net cash flows may differ from those estimated due to, but not limited to, the following:

- Production rates could differ from those estimated both in terms of timing and amount;
- Future prices and economic conditions will likely differ from those at year-end;
- Future production and development costs will be determined by future events and may differ from those at year-end; and
- Estimated income taxes may differ in terms of amounts and timing due to the above factors as well as changes in enacted rates and the impact of future expenditures on unproved properties.

The standardized measure of discounted future net cash flows is determined by using estimated quantities of proved reserves and taking into account the future periods in which they are expected to be developed and produced based on year-end economic conditions. The estimated future production is priced at year-end prices, except that future gas prices are increased, where applicable, for fixed and determinable price escalations provided by contract. At December 31, 2002, no such contractual arrangements existed. The resulting estimated future cash inflows are reduced by estimated future costs to develop and produce the proved reserves based on year-end cost levels. In addition, the Company has also deducted certain other estimated costs deemed necessary to derive the estimated pretax future net cash flows from the proved reserves including direct general and administrative costs of exploration and production operations and reclamation and environmental remediation costs. Deducting future income tax expenses then reduces the estimated pretax future net cash flows further. Such income taxes are determined by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax cash flows relating to the Company's proved oil and gas reserves less the tax basis of the properties involved. At December 31, 2002, there were no legislated future tax rate changes. The resultant future net cash flows are reduced to present value amounts by applying the Statement 69 mandated 10% discount factor. The result is referred to as "Standardized Measure of Discounted Future Net Cash Flows from Estimated Production of Proved Oil and Gas Reserves after Income Taxes".

	2002	2001	2000
		($ millions)	
Future cash inflows	8,964	2,266	8,176
Future production and development costs	(3,007)	(652)	(633)
Other related future costs	(314)	(283)	(175)
Future income tax expenses	(2,094)	(521)	(3,426)
Future net cash flows	3,549	810	3,942
Discount at 10%	(1,822)	(370)	(2,009)
Standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves after income taxes	1,727	440	1,933

Summary of Changes in the Standardized Measure of Discounted Future Net Cash Flows from Estimated Production of Proved Oil and Gas Reserves after Income Taxes

	2002	2001	2000
		($ millions)	
Balance, beginning of year	440	1,933	749
Increase (decrease) in discounted future net cash flows:			
Sales and transfers of oil and gas net of related costs	(192)	(297)	(275)
Revisions to estimates of proved reserves:			
Prices	713	(3,055)	3,886
Development costs	(38)	(50)	(3)
Production costs	(49)	(9)	55
Quantities	(45)	(2)	(363)
Extensions, discoveries, and improved recovery less related costs	1,387	23	177
Development costs incurred during the period	112	81	69
Purchases of reserves in place	—	—	41
Sales of reserves in place	(7)	(1)	(989)
Accretion of discount	68	361	115
Income taxes	(697)	1,472	(1,292)
Other	35	(16)	(237)
Balance, end of year	1,727	440	1,933

EXHIBIT 2

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2002, including reconciliation to U.S. GAAP (Note 19)

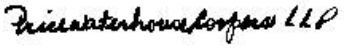
AUDITORS' REPORT

To the Shareholders of Suncor Energy Inc.

We have audited the consolidated balance sheets of Suncor Energy Inc. as at December 31, 2002 and 2001 and the consolidated statements of earnings, cash flows and changes in shareholders' equity for each of the years in the three year period ended December 31, 2002. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2002 in accordance with Canadian generally accepted accounting principles.

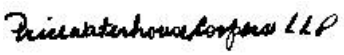


PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

January 17, 2003

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA-U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the company's financial statements, such as the change described in note 1 to the consolidated financial statements. Our report to the shareholders dated January 17, 2003 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors' Report when the change is properly accounted for and adequately disclosed in the financial statements.



PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

January 17, 2003

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Suncor Energy Inc. is an integrated Canadian energy company, comprised of three operating segments: Oil Sands, Natural Gas and Energy Marketing and Refining.

Oil Sands includes the production of light sweet and light sour crude oil, diesel fuel and various custom blends from oil sands mined in the Athabasca region of northeastern Alberta, and the marketing of these products in Canada and the United States.

Natural Gas includes the exploration, acquisition, development, production, transportation and marketing of natural gas and crude oil in Canada and the United States.

Energy Marketing and Refining includes the manufacture, transportation and marketing of petroleum and petrochemical products, primarily in Ontario and Quebec. Petrochemical products are also sold in the United States and Europe.

The significant accounting policies of the company are summarized below:

(a) Principles of Consolidation and the Preparation of Financial Statements

These consolidated financial statements are prepared and reported in Canadian dollars in accordance with Canadian generally accepted accounting principles (GAAP), which differ in some respects from GAAP in the United States. These differences are quantified and explained in

note 19.

The consolidated financial statements include the accounts of Suncor Energy Inc. and its subsidiaries and the company's proportionate share of the assets, liabilities, revenues, expenses and cash flows of its joint ventures.

The timely preparation of financial statements requires that management make estimates and assumptions, and use judgment regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

(b) Cash Equivalents and Investments

Cash equivalents consist primarily of term deposits, certificates of deposit and all other highly liquid investments with a maturity at the time of purchase of three months or less. Investments with maturities greater than three months to one year are classified as short-term investments, while those with maturities in excess of one year are classified as long-term investments. Cash equivalents and short-term investments are stated at cost, which approximates market value.

(c) Revenues

Crude oil sales from upstream operations (Oil Sands and Natural Gas) to downstream operations (Energy Marketing and Refining) are based on actual product shipments. On consolidation, revenues and purchases related to these sales transactions are eliminated from operating revenues and purchases of crude oil and products.

The company also uses a portion of its natural gas production for internal consumption at its oil sands plant and Sarnia refinery. On consolidation, revenues from these sales are eliminated from operating revenues, crude oil and products purchases, and operating, selling and general expenses.

Revenues associated with sales of crude oil, natural gas, petroleum and petrochemical products and all other items not eliminated on consolidation are recorded when title passes to the customer and delivery has taken place. Revenues from oil and natural gas production from properties in which the company has an interest with other producers are recognized on the basis of the company's net working interest.

(d) Property, Plant and Equipment

Cost

Property, plant and equipment are recorded at cost.

Expenditures to acquire and develop Oil Sands mining properties, and net costs relating to production during the development phase, are capitalized. Development costs to expand the capacity of existing mines or to develop mine areas substantially in advance of current production are also capitalized.

The company follows the successful efforts method of accounting for its conventional and in-situ oil sands crude oil operations and its natural gas operations. Under the successful efforts method, acquisition costs of proved and unproved properties are capitalized. Costs of unproved properties are transferred to proved properties when proved reserves are confirmed. Exploration costs, including geological and geophysical costs, are expensed as incurred. Exploratory drilling costs are initially capitalized. If it is determined that the well does not contain proved reserves, the capitalized exploratory drilling costs are charged to expense, as dry hole costs, at that time. Related land costs are expensed through the amortization of unproved properties as covered under the Natural Gas section of the depreciation, depletion and amortization policy on page 42.

Development costs, which include the costs of wellhead equipment, development drilling costs, gas plants and handling facilities, applicable geological and geophysical costs and the costs of acquiring or constructing support facilities and equipment are capitalized. Costs incurred to operate and maintain wells and equipment and to lift oil and gas to the surface are expensed as operating costs.

Costs incurred at the inception of operations are expensed.

Interest Capitalization

Interest costs relating to major capital projects in progress and to the portion of non-producing oil and gas properties expected to become producing are capitalized as part of property, plant and equipment. Capitalization of interest ceases when the capital asset is substantially complete and ready for its intended productive use.

Leases

Leases that transfer substantially all the benefits and risks of ownership to the company are recorded as capital leases and classified as property, plant and equipment with offsetting long-term debt. All other leases are classified as operating leases under which leasing costs are expensed in the period incurred.

Gains and losses on the sale and leaseback of assets recorded as capital leases are deferred and amortized to earnings in proportion to the amortization of leased assets.

Depreciation, Depletion and Amortization

OIL SANDS Property, plant and equipment are depreciated over their useful lives on a straight-line basis, commencing when the assets are placed into service. Mine and mobile equipment is depreciated over periods ranging from three to 20 years and plant and other property and equipment, including leases in service, primarily over four to 40 years. Capitalized costs related to the in-progress phase of projects are not depreciated until the facilities are substantially complete and ready for commercial production to commence.

NATURAL GAS Acquisition costs of unproved properties that are individually significant are evaluated for impairment by management. Impairment of unproved properties that are not individually significant is provided for through amortization over the average projected holding period for that portion of acquisition costs not expected to become producing, based on historical experience.

Acquisition costs of proved properties are depleted using the unit of production method based on proved reserves. Capitalized exploratory drilling costs and development costs are depleted on the basis of proved developed reserves. For purposes of the depletion calculation, production and reserves volumes for oil and natural gas are converted to a common unit of measure on the basis of their approximate relative energy content. Gas plants, support facilities and equipment are depreciated on a straight-line basis over their useful lives, which average 12 years.

ENERGY MARKETING AND REFINING Depreciation of property, plant and equipment is provided for on a straight-line basis over their useful lives. The refinery and additions are depreciated over an average of 30 years, service stations and related equipment over an average of 20 years and other facilities and equipment over three to 25 years.

Reclamation and Environmental Remediation Costs

Reclamation and environmental remediation costs for identified sites are estimated and charged against earnings when a regulatory or statutory requirement or contractual agreement exists, or when management has made a decision to decommission or restore a site, providing that assessments indicate that such costs are probable and reasonably estimable.

Estimated reclamation costs in the company's upstream operations are accrued on the unit of production basis. Estimated environmental remediation costs, which are predominantly in the company's downstream operations, are accrued during the period for those sites where assessments indicate that such work is required.

Costs are accrued based upon currently known information, estimated timing of remedial actions, and existing regulatory requirements and technology. Changes in these factors may result in material changes to estimated costs, which will be recognized prospectively when known.

Impairment

Property, plant and equipment are reviewed for impairment whenever events or conditions indicate that their net carrying amount, less related provisions for reclamation and environmental remediation costs and future income taxes, may not be recoverable from estimated undiscounted future cash flows. If it is determined that the estimated net recoverable amount is less than the net carrying amount, a write-down to the estimated net recoverable amount is recognized during the period, with a charge to earnings.

Disposals

Gains or losses on disposals of non-oil and gas property, plant and equipment are recognized in earnings. For oil and gas property, plant and equipment, gains or losses are recognized in earnings for significant disposals or disposal of an entire property. However, the acquisition cost of an unproved property surrendered or abandoned that is not individually significant, or a partial abandonment of a proved property, is charged to accumulated depreciation, depletion or amortization.

(e) Deferred Charges and Other

Overburden removal may precede mining of the oil sands deposit by as much as two years. In order to match expense with the oil sands mined in the year, the company employs a deferral method of accounting for overburden removal costs where all such costs are initially recorded as a deferred charge (see note 3), rather than expensing overburden removal costs as incurred. These deferred charges are allocated to the mining activity in the year on a last-in, first-out (LIFO) basis using a life-of-mine stripping ratio for each mine pit whereby all of the overburden to be removed is related to all of the oil sands proved and probable ore reserves. This expense is reported as part of the depreciation, depletion and amortization expense in the consolidated statements of earnings. Stripping ratios are regularly reviewed to reflect changes in operating experience and other factors.

The cost of major maintenance shutdowns is deferred and amortized on a straight-line basis over the period to the next shutdown, which varies from three to seven years. Normal maintenance and repair costs are charged to expense as incurred.

(f) Employee Future Benefits

The company's employee future benefit programs consist of defined benefit and defined contribution pension plans, as well as other post-retirement benefits.

The estimated future cost of providing defined benefit pension and other post-retirement benefits is actuarially determined using management's best estimates of demographic and financial assumptions, and such cost is accrued ratably from the date of hire of the employee to the date the employee becomes fully eligible to receive the benefits. The discount rate used to determine accrued benefit obligations is based upon a year-end market rate of interest. Company contributions to the defined contribution plan are expensed as incurred.

(g) Inventories

Inventories of crude oil and refined products are valued at the lower of cost using the LIFO method and net realizable value.

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

(h) Derivative Financial Instruments

The company periodically enters into derivative financial instrument contracts such as forwards, futures, swaps and options to hedge against the potential adverse impact of market prices for its petroleum and natural gas products and to manage the exposure to fluctuations in its Canadian dollar earnings and cash flows due to adverse foreign currency exchange movements. The company also periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to manage exposure to interest rate fluctuations.

These derivative contracts are initiated within the guidelines of the company's risk management policies, which require stringent authorities for approval and commitment of contracts, designation of the contracts by management as hedges of the related transactions, and monitoring of the effectiveness of such contracts in reducing the related risks. Contract maturities are consistent with the settlement dates of the related hedged transactions.

Derivative contracts accounted for as hedges are not recognized in the consolidated balance sheets. Gains or losses on these contracts, including realized gains and losses on hedging derivative contracts settled prior to maturity, are recognized in earnings and cash flows when the related sales revenues, costs, interest expense and cash flows are recognized. Gains or losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings and cash flows when those changes occur.

Commencing in the fourth quarter of 2002, the company began to use energy derivatives, including physical and financial swaps, forwards and options to gain market information and to earn trading revenues. Trading activities are accounted for at fair value.

(i) Foreign Currency Translation

Monetary assets and liabilities in foreign currencies are translated to Canadian dollars at rates of exchange in effect at the end of the period. Other assets and related depreciation, depletion and amortization, other liabilities, and revenues and expenses are translated at rates of exchange in effect at the respective transaction dates. The resulting exchange gains and losses are included in earnings.

(j) Stock-based Compensation Plans

Under the company's common share option programs (see note 11), common share options are granted to executives, employees and non-employee directors. Compensation expense is not recognized at the initial grant of the common share options and consideration paid to the company on exercise of stock options is credited to share capital.

Stock-based compensation awards that are to be settled in cash are measured using the fair value based method of accounting.

(k) Recently Issued Accounting Standards

Hedging Relationships

Canadian Accounting Guideline 13 (AcG 13) "Hedging Relationships" is applicable to the company's hedging relationships in 2004 and subsequent fiscal years. AcG 13 specifies the circumstances in which hedge accounting is appropriate, including the identification, documentation, designation and effectiveness of hedges, as well as the discontinuance of hedge accounting. The Guideline does not specify hedge accounting methods. The company is evaluating the impact of implementing the standard.

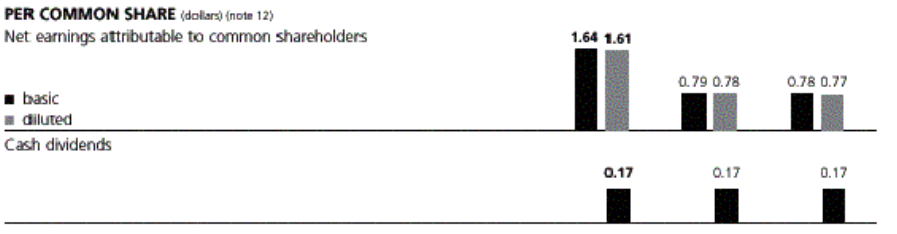
Asset Retirement Obligations

A new Canadian standard "Asset Retirement Obligations" (ARO) substantially harmonizes Canadian GAAP with U.S. GAAP (see note 19). The standard requires that a liability associated with the retirement of property, plant and equipment be recognized when incurred. The liability would be measured initially at fair value and the resulting costs capitalized. Capitalized costs would be amortized according to normal amortization practices. Subsequent to initial recognition the ARO liability would be adjusted for the accretion of discount and changes in the amount or timing of the underlying future cash flows. The standard is effective no later than January 1, 2004. The company is evaluating the impact of implementing the standard.

CONSOLIDATED STATEMENTS OF EARNINGS

for the years ended December 31

($ millions)	2002	2001	2000
REVENUES			
Operating revenues (notes 5, 15, 17 and 18)	**4 902**	4 194	3 385
Interest	**2**	5	3
	4 904	4 199	3 388
EXPENSES			
Purchases of crude oil and products (note 15)	**1 298**	1 595	807
Operating, selling and general	**1 292**	1 012	918
Depreciation, depletion and amortization	**585**	360	365
Exploration (note 18)	**26**	22	53
Royalties	**98**	134	199
Taxes other than income taxes (note 18)	**374**	367	361
(Gain) on disposal of assets	**(2)**	(7)	(148)
(Gain) on sale of retail natural gas marketing business (note 16)	**(38)**	—	—
Project start-up costs	**3**	141	15
Write-off of oil shale assets	**—**	48	125
Restructuring (note 18)	**—**	(2)	65
Financing expenses (note 13)	**124**	16	8
	3 760	3 686	2 768
EARNINGS BEFORE INCOME TAXES	**1 144**	513	620
Provision for income taxes (note 8)			
Current	**74**	4	45
Future	**309**	121	198
	383	125	243
NET EARNINGS	**761**	388	377
Dividends on preferred securities, net of tax (note 10)	**(28)**	(26)	(26)
Revaluation of US$ preferred securities, net of tax (note 1)	**1**	(11)	(6)
Net earnings attributable to common shareholders	**734**	351	345



See accompanying Summary of Significant Accounting Policies and Notes.

CONSOLIDATED BALANCE SHEETS
as at December 31

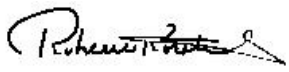
($ millions)	2002	2001
ASSETS		
Current assets		
Cash and cash equivalents	**15**	1
Accounts receivable (notes 9(c) and 17)	**403**	306
Inventories (note 14)	**266**	258
Income taxes recoverable	**—**	28
Future income taxes (note 8)	**38**	29
Total current assets	**722**	622
Property, plant and equipment, net (note 2)	**7 641**	7 141
Deferred charges and other (note 3)	**185**	199
Future income taxes (note 8)	**135**	132
Total assets	**8 683**	8 094
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term debt	**—**	31
Accounts payable and accrued liabilities (notes 6 and 7)	**716**	672
Income taxes payable	**34**	—
Taxes other than income taxes	**37**	42
Future income taxes (note 8)	**10**	28
Total current liabilities	**797**	773
Long-term debt (note 4)	**2 686**	3 113
Accrued liabilities and other (notes 6 and 7)	**226**	251
Future income taxes (note 8)	**1 516**	1 177
Total liabilities	**5 225**	5 314
Commitments and contingencies (note 9)		
Shareholders' equity		
Preferred securities (note 10)	**523**	525
Share capital (note 11)	**578**	555
Retained earnings	**2 357**	1 700
Total shareholders' equity	**3 458**	2 780
Total liabilities and shareholders' equity	**8 683**	8 094

See accompanying Summary of Significant Accounting Policies and Notes.

Approved on behalf of the Board:



Rick George
Director



Robert Korthals
Director

CONSOLIDATED STATEMENTS OF CASH FLOWS
for the years ended December 31

($ millions)	2002	2001	2000
OPERATING ACTIVITIES			
Cash flow provided from operations(a)	**1 440**	831	958
Decrease (increase) in operating working capital			
Accounts receivable	**(97)**	101	(130)
Inventories	**(8)**	(66)	(31)
Accounts payable and accrued liabilities	**44**	(37)	93
Taxes payable	**77**	(17)	18
Cash provided from operating activities	**1 456**	812	908
CASH USED IN INVESTING ACTIVITIES(a)	**(861)**	(1 680)	(1 607)
NET CASH SURPLUS (DEFICIENCY) BEFORE FINANCING ACTIVITIES	**595**	(868)	(699)
FINANCING ACTIVITIES			
Increase (decrease) in short-term debt	**(31)**	(33)	32
Proceeds from issuance of long-term debt	**797**	500	—
Net increase (decrease) in other long-term debt	**(1 245)**	486	792

Issuance of common shares under stock option plans	**19**	15	9
Dividends paid on preferred securities	**(48)**	(48)	(47)
Dividends paid on common shares	**(73)**	(72)	(71)
Cash provided from (used in) financing activities	**(581)**	848	715
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**14**	(20)	16
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**1**	21	5
CASH AND CASH EQUIVALENTS AT END OF YEAR	**15**	1	21

(a) See Schedules of Segmented Data on pages 50 and 51.

See accompanying Summary of Significant Accounting Policies and Notes.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

for the years ended December 31

($ millions)	Preferred Securities	Share Capital	Retained Earnings
At December 31, 1999, as previously reported	514	524	1 070
Retroactive adjustment for change in accounting policy, net of tax (note 1)	(12)	—	9
At December 31, 1999, as restated	502	524	1 079
Net earnings	—	—	377
Dividends paid on preferred securities, net of tax	—	—	(26)
Dividends paid on common shares	—	—	(71)
Issued for cash under stock option plans	—	9	—
Issued under dividend reinvestment plan	—	4	(4)
Income taxes — impact of new standard	—	—	75
Revaluation of US$ preferred securities (note 1)	8	—	(6)
At December 31, 2000, as restated	510	537	1 424
Net earnings	—	—	388
Dividends paid on preferred securities, net of tax	—	—	(26)
Dividends paid on common shares	—	—	(72)
Issued for cash under stock option plans	—	15	—
Issued under dividend reinvestment plan	—	3	(3)
Revaluation of US$ preferred securities (note 1)	15	—	(11)
At December 31, 2001, as restated	**525**	**555**	**1 700**
Net earnings	**—**	**—**	**761**
Dividends paid on preferred securities, net of tax	**—**	**—**	**(28)**
Dividends paid on common shares	**—**	**—**	**(73)**
Issued for cash under stock option plans	**—**	**19**	**—**
Issued under dividend reinvestment plan	**—**	**4**	**(4)**
Revaluation of US$ preferred securities (note 1)	**(2)**	**—**	**1**
At December 31, 2002	**523**	**578**	**2 357**

See accompanying Summary of Significant Accounting Policies and Notes.

SCHEDULES OF SEGMENTED DATA (a)

for the years ended December 31

	Oil Sands			Natural Gas			Energy Marketing and Refining		
($ millions)	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**
EARNINGS									
Revenues(b)									
Operating revenues	**2 284**	1 227	544	**255**	382	237	**2 361**	2 585	2 604
Intersegment revenues (note 15)(c)	**375**	158	792	**60**	76	191	**—**	3	—
Interest	**—**	—	—	**—**	—	—	**—**	—	—
	2 659	1 385	1 336	**315**	458	428	**2 361**	2 588	2 604
Expenses									
Purchases of crude oil and products (note 15)	**149**	99	3	**16**	9	—	**1 564**	1 721	1 783
Operating, selling and general	**806**	481	467	**69**	64	74	**352**	350	310
Depreciation, depletion and amortization	**450**	233	232	**75**	70	78	**58**	56	54
Exploration	**9**	—	—	**17**	22	53	**—**	—	—
Royalties	**33**	30	98	**65**	104	101	**—**	—	—
Taxes other than income taxes	**23**	12	12	**2**	3	3	**348**	351	345
(Gain) loss on disposal of assets	**2**	1	—	**(4)**	(8)	(147)	**—**	—	(1)
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**—**	—	—	**(38)**	—	—
Project start-up costs	**3**	141	15	**—**	—	—	**—**	—	—
Write-off of oil shale assets	**—**	—	—	**—**	—	—	**—**	—	—
Restructuring	**—**	—	—	**—**	(2)	65	**—**	—	—
Financing expenses	**—**	—	—	**—**	—	—	**—**	—	—
	1 475	997	827	**240**	262	227	**2 284**	2 478	2 491
Earnings (loss) before income taxes	**1 184**	388	509	**75**	196	201	**77**	110	113

Provision for income taxes	**(391)**	(105)	(194)	**(40)**	(79)	(103)	**(16)**	(30)	(32)
Net earnings (loss)	**793**	283	315	**35**	117	98	**61**	80	81
As at December 31									
TOTAL ASSETS	**6 896**	6 409	5 079	**765**	722	762	**968**	934	911
CAPITAL EMPLOYED(d)	**4 540**	1 398	1 412	**449**	317	412	**491**	483	386

(a) The company currently has no foreign geographic segments. See note 18 for information on export sales. Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.

(b) One customer in the Oil Sands segment represented 10% or more ($641 million) of the company's 2002 consolidated revenues (2001 —one customer represented 10% or more ($450 million); 2000 — two customers represented 10% or more ($493 million and $355 million)).

(c) Intersegment revenues are recorded at prevailing fair market prices and accounted for as if the sales were to third parties.

(d) Capital employed — the total of shareholders' equity and short-term and long-term debt, less capitalized costs related to major projects in progress.

See accompanying Summary of Significant Accounting Policies and Notes.

SCHEDULES OF SEGMENTED DATA (a) (continued)
for the years ended December 31

	Corporate and Eliminations			Total		
($ millions)	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**
EARNINGS						
Revenues(b)						
Operating revenues	**2**	—	—	**4 902**	4 194	3 385
Intersegment revenues (note 15) (c)	**(435)**	(237)	(983)	**—**	—	—
Interest	**2**	5	3	**2**	5	3
	(431)	(232)	(980)	**4 904**	4 199	3 388
Expenses						
Purchases of crude oil and products (note 15)	**(431)**	(234)	(979)	**1 298**	1 595	807
Operating, selling and general	**65**	117	67	**1 292**	1 012	918
Depreciation, depletion and amortization	**2**	1	1	**585**	360	365
Exploration	**—**	—	—	**26**	22	53
Royalties	**—**	—	—	**98**	134	199
Taxes other than income taxes	**1**	1	1	**374**	367	361
(Gain) loss on disposal of assets	**—**	—	—	**(2)**	(7)	(148)
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**(38)**	—	—
Project start-up costs	**—**	—	—	**3**	141	15
Write-off of oil shale assets	**—**	48	125	**—**	48	125
Restructuring	**—**	—	—	**—**	(2)	65
Financing expenses	**124**	16	8	**124**	16	8
	(239)	(51)	(777)	**3 760**	3 686	2 768
Earnings (loss) before income taxes	**(192)**	(181)	(203)	**1 144**	513	620
Provision for income taxes	**64**	89	86	**(383)**	(125)	(243)
Net earnings (loss)	**(128)**	(92)	(117)	**761**	388	377
As at December 31						
TOTAL ASSETS	**54**	29	81	**8 683**	8 094	6 833
CAPITAL EMPLOYED(d)	**154**	33	22	**5 634**	2 231	2 232

SCHEDULES OF SEGMENTED DATA (a) (continued)
for the years ended December 31

	Oil Sands			Natural Gas			Energy Marketing and Refining		
($ millions)	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**	**2002**	**2001**	**2000**
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash provided from (used in) operating activities:									
Cash flow provided from (used in) operations									
Net earnings (loss)	**793**	283	315	**35**	117	98	**61**	80	81
Exploration expenses									
Cash	**—**	—	—	**6**	12	12	**—**	—	—
Dry hole costs	**—**	—	—	**11**	10	41	**—**	—	—

Non-cash items included in earnings									
Depreciation, depletion and amortization	**450**	233	232	**75**	70	78	**58**	56	54
Future income taxes	**379**	89	189	**37**	76	101	**(35)**	18	(16)
Current income tax provision allocated to Corporate	**12**	16	5	**3**	3	2	**51**	12	48
(Gain) loss on disposal of assets	**2**	1	—	**(4)**	(8)	(147)	**—**	—	(1)
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**—**	—	—	**(38)**	—	—
Write-off of oil shale assets	**—**	—	—	**—**	—	—	**—**	—	—
Restructuring	**—**	—	—	**—**	(3)	56	**—**	—	—
Other	**12**	(4)	(12)	**2**	3	(4)	**9**	2	6
Overburden removal outlays	**(160)**	(31)	(48)	**—**	—	—	**—**	—	—
Overburden removal outlays — Project Millennium (start-up period)	**—**	(88)	(27)	**—**	—	—	**—**	—	—
Increase (decrease) in deferred credits and other	**(8)**	(13)	1	**(1)**	—	1	**1**	(3)	2
Total cash flow provided from (used in) operations	**1 480**	486	655	**164**	280	238	**107**	165	174
Decrease (increase) in operating working capital	**(121)**	(35)	(169)	**22**	44	27	**(10)**	17	40
Total cash provided from (used in) operating activities	**1 359**	451	486	**186**	324	265	**97**	182	214
Cash provided from (used in) investing activities:									
Capital and exploration expenditures	**(617)**	(1 479)	(1 808)	**(163)**	(132)	(127)	**(60)**	(54)	(45)
Deferred maintenance shutdown expenditures	**(9)**	(5)	(3)	**—**	(2)	(1)	**(18)**	(9)	(9)
Deferred outlays and other investments	**(4)**	(2)	(5)	**—**	(1)	—	**(18)**	(9)	(7)
Proceeds from disposals	**—**	10	101	**5**	22	314	**62**	1	2
Total cash provided from (used in) investing activities	**(630)**	(1 476)	(1 715)	**(158)**	(113)	186	**(34)**	(71)	(59)
Net cash surplus (deficiency) before financing activities	**729**	(1 025)	(1 229)	**28**	211	451	**63**	111	155

(a) The company currently has no foreign geographic segments. See note 18 for information on export sales. Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.

See accompanying Summary of Significant Accounting Policies and Notes.

SCHEDULES OF SEGMENTED DATA (a) (continued)
for the years ended December 31

($ millions)	Corporate and Eliminations 2002	Corporate and Eliminations 2001	Corporate and Eliminations 2000	Total 2002	Total 2001	Total 2000
CASH FLOW BEFORE FINANCING ACTIVITIES						
Cash provided from (used in) operating activities:						
Cash flow provided from (used in) operations						
Net earnings (loss)	**(128)**	(92)	(117)	**761**	388	377
Exploration expenses						
Cash	**—**	—	—	**6**	12	12
Dry hole costs	**—**	—	—	**11**	10	41
Non-cash items included in earnings						
Depreciation, depletion and amortization	**2**	1	1	**585**	360	365
Future income taxes	**(72)**	(62)	(76)	**309**	121	198
Current income tax provision allocated to Corporate	**(66)**	(31)	(55)	**—**	—	—
(Gain) loss on disposal of assets	**—**	—	—	**(2)**	(7)	(148)
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**(38)**	—	—
Write-off of oil shale assets	**—**	48	125	**—**	48	125
Restructuring	**—**	—	—	**—**	(3)	56
Other	**(3)**	7	(7)	**20**	8	(17)
Overburden removal outlays	**—**	—	—	**(160)**	(31)	(48)
Overburden removal outlays — Project Millennium (start-up period)	**—**	—	—	**—**	(88)	(27)
Increase (decrease) in deferred credits and other	**(44)**	29	20	**(52)**	13	24
Total cash flow provided from (used in) operations	**(311)**	(100)	(109)	**1 440**	831	958
Decrease (increase) in operating working capital	**125**	(45)	52	**16**	(19)	(50)
Total cash provided from (used in) operating activities	**(186)**	(145)	(57)	**1 456**	812	908
Cash provided from (used in) investing activities:						
Capital and exploration expenditures	**(37)**	(13)	(18)	**(877)**	(1 678)	(1 998)
Deferred maintenance shutdown expenditures	**—**	—	—	**(27)**	(16)	(13)

Deferred outlays and other investments	**(2)**	(7)	(1)	**(24)**	(19)	(13)
Proceeds from disposals	**—**	—	—	**67**	33	417
Total cash provided from (used in) investing activities	**(39)**	(20)	(19)	**(861)**	(1 680)	(1 607)
Net cash surplus (deficiency) before financing activities	**(225)**	(165)	(76)	**595**	(868)	(699)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Change in Accounting Policy

Effective January 1, 2002, the company retroactively adopted the new Canadian accounting standard for Foreign Currency Translation, and as a result, all prior periods have been restated. This new standard applies to the company's foreign currency denominated long-term debt and preferred securities (see notes 4 and 10). The impact of this new standard on the consolidated balance sheets and statements of earnings is as follows:

Change in Consolidated Balance Sheets

($ millions, increase (decrease))	2002	2001
Future income taxes — long-term liabilities	**3**	(4)
Preferred securities	**(2)**	15
Retained earnings	**9**	(11)

Change in Consolidated Statements of Earnings

($ millions, increase (decrease))	2002	2001	2000
Financing expenses	**(10)**	—	—
Future income taxes	**2**	—	—
Net earnings	**8**	—	—
Revaluation of US$preferred securities, net of tax	**1**	(11)	(6)
Net earnings attributable to common shareholders	**9**	(11)	(6)
Per common share — basic and diluted (dollars)	**$0.02**	($0.02)	($0.01)

2. Property, Plant and Equipment

	2002		2001	
($ millions)	Cost	Accumulated Provision	Cost	Accumulated Provision
Oil Sands				
Plant	**5 340**	**691**	1 744	557
Mine and mobile equipment	**1 154**	**381**	1 008	337
Pipeline costs	**81**	**26**	81	23
Capital leases	**121**	**12**	109	6
Major projects in progress				
Project Millennium	**—**	**—**	3 618	8
Firebag and other	**702**	**—**	275	—
	7 398	**1 110**	6 835	931
Natural Gas				
Proved properties	**1 053**	**480**	931	423
Unproved properties	**150**	**41**	148	48
Pipeline	**20**	**18**	20	17
Other support facilities and equipment	**16**	**11**	14	8
	1 239	**550**	1 113	496
Energy Marketing and Refining				
Refinery	**800**	**417**	771	391
Marketing and transportation	**461**	**229**	434	209
	1 261	**646**	1 205	600
Corporate	**55**	**6**	19	4
	9 953	**2 312**	9 172	2 031
Net property, plant and equipment		**7 641**		7 141

3. Deferred Charges and Other

($ millions)	2002	2001
Oil sands overburden removal costs (see below)	**68**	101
Deferred maintenance shutdown costs	**44**	34
Other	**73**	64

Total deferred charges and other	**185**	199
Oil sands overburden removal costs		
Balance — beginning of year	**101**	76
Outlays during the year	**160**	119
Depreciation on equipment during year	**9**	9
	270	204
Amortization during year	**(202)**	(103)
Balance — end of year	**68**	101

4. Long-term Debt

($ millions)	**2002**	**2001**
Fixed-term debt, redeemable at the option of the company		
7.15% Notes, denominated in U.S. dollars, due in 2032 (a)	**790**	—
6.70% Series 2 Medium Term Notes, due in 2011 (b)	**500**	500
6.80% Medium Term Notes, due in 2007 (b)	**250**	250
6.10% Medium Term Notes, due in 2007 (b)	**150**	150
7.40% Debentures, Series C, due in 2004	**125**	125
	1 815	1 025
Revolving-term debt, with interest at variable rates (see Credit Facilities)		
Commercial Paper, interest at December 31, 2002 — 2.9% (2001 — 2.5%) (b,c)	**548**	861
Bank debt, interest at December 31, 2002 — 3.5% (2001 — 2.6%) (b)	**199**	1 112
Total unsecured long-term debt	**2 562**	2 998
Other secured long-term debt with interest rates averaging 6.1% (2001 — 7.1%)	**5**	6
Capital leases (d,e)	**119**	109
Total long-term debt	**2 686**	3 113

(a) In 2002, the company issued 7.15% Notes with a principal amount of US$500 million (Cdn$ equivalent of $790 million at December 31, 2002). The net proceeds received were used to repay commercial paper and bank debt.

(b) The company has entered into various interest rate swap transactions at December 31, 2002. The swap transactions result in an average effective interest rate that is different from the stated interest rate of the related underlying long-term debt instruments.

Description of Swap Transactions	**Principal Swapped ($ millions)**	**Swap Maturity**	**2002 Effective Interest Rate**
Swap of 6.70% Series 2 Medium Term Notes to floating rates	200	2011	4.0%
Swap of 6.80% Medium Term Notes to floating rates	250	2007	4.5%
Swap of 6.10% Medium Term Notes to floating rates	150	2007	3.8%
Swap of floating rate Commercial Paper to fixed rates	110	2003	5.3%
Swap of U.S. dollar denominated floating rate debt to Canadian dollar denominated floating rates	US$126	2003	3.2%

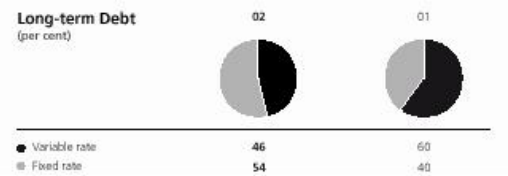
(c) The company is authorized to issue commercial paper to a maximum of $900 million having a term not to exceed 364 days. Commercial paper is supported by unutilized credit and term loan facilities.

(d) Obligations under capital leases are as follows:

($ millions)	**2002**	**2001**
Energy services assets lease with interest at 6.82%, maturing in 2004	**101**	101
Other equipment leases with interest rates between prime plus 0.5% and 6.25%, and maturity dates ranging from 2008 to 2010	**18**	8
	119	109

(e) Future minimum amounts payable under capital leases and other long-term debt are as follows:

($ millions)	**Capital Leases**	**Other Long-term Debt**
2003	10	3
2004	110	324
2005	3	—
2006	3	550
2007	3	400
Later years	9	1 290
Total minimum payments	138	2 567
Less amount representing imputed interest	19	
Present value of obligation under capital leases	119	



Credit Facilities

At December 31, 2002, the company had available credit and term loan facilities of $1,948 million, of which $1,139 million was undrawn, as follows:

($ millions)	
Facility that is fully revolving for 364 days, has a term period of three years and expires in 2006	600
Facility for US$126 million that is non-revolving, has been fully drawn and expires in 2004	199
Facility that is fully revolving and expires in 2004	1 058
Undrawn facilities that can be terminated at any time at the option of the lenders	91
Total available credit facilities	1 948
Drawn from credit facilities	(199)
Credit facilities supporting commercial paper program and standby letters of credit	(610)
Total undrawn credit facilities	1 139

At December 31, 2002, the company had issued $62 million in letters of credit to various third parties.

5. Financial Instruments

Derivatives are financial instruments that either imitate or counter the price movements of stocks, bonds, currencies, commodities and interest rates. Suncor uses derivatives to reduce (hedge) its exposure to fluctuations in commodity prices and foreign currency exchange rates and to manage interest or currency-sensitive assets and liabilities. Suncor also uses derivatives for trading purposes. When used in a trading activity, the company is attempting to realize a gain on the fluctuations in the market value of the derivative.

Forwards and futures are contracts to purchase or sell a specific item at a specified date and price. When used as hedges, forwards and futures manage the exposure to losses that could result if commodity prices or foreign currency exchange rates change adversely.

An option is a contract where its owner, for a fee, has purchased the right (but not the obligation) to buy or sell a specified item at a fixed price during a specified period. Options used as hedges can protect against adverse changes in commodity prices, interest rates, or foreign currency exchange rates.

A costless collar is a combination of two option contracts that limits the holder's exposure to changes in prices to within a specific range. The "costless" nature of this derivative is achieved by buying a put option (the right to sell) for consideration equal to the premium received from selling a call option (the right to purchase).

A swap is a contract where two parties exchange commodity, currency, interest or other payments in order to alter the nature of the payments. For example, fixed interest rate payments on debt may be converted to payments based on a floating interest rate, or vice versa; a domestic currency debt may be converted to a foreign currency debt.

See next page for more technical details and amounts.

(a) Balance Sheet Financial Instruments

The company's financial instruments recognized in the consolidated balance sheets consist of cash and cash equivalents, accounts receivable, derivative contracts not accounted for as hedges, investments in Southern Pacific Petroleum (SPP), substantially all current liabilities (except for income taxes payable and future income taxes), and long-term debt.

The estimated fair values of recognized financial instruments have been determined based on the company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

(i) The fair values of cash and cash equivalents, accounts receivable and current liabilities approximate their carrying amounts due to the short-term maturity of these instruments.

(ii) The fair value of the company's investment in the shares of SPP is determined based on quoted market prices of these shares.

(iii) At December 31, 2002, the company had outstanding crude oil and U.S. dollar swap contracts maturing in 2004, fixing the purchase price of 2,130,000 barrels of crude oil at Cdn$49 million. These derivative contracts, which have not been accounted for as hedges, had a fair value and carrying value of $22 million at December 31, 2002 (2001 — $13 million; 2000 — $10 million) (see note 9c).

The following table summarizes estimated fair value information about the company's long-term debt at December 31:

	2002		2001	
($ millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term Debt				
Fixed-term	**1 815**	**1 991**	1 025	1 047
Revolving-term	**747**	**747**	1 973	1 974
Other	**5**	**5**	6	6
Capital leases	**119**	**119**	109	109

The fair values of the company's fixed and revolving-term long-term debt, capital leases, and other long-term debt were determined through comparisons to similar debt instruments.

(b) Unrecognized Derivative Financial Instruments

The company periodically is also a party to certain derivative financial instruments, which are not recognized in the consolidated balance sheets, as follows:

Revenue and Margin Hedges

The company periodically enters into crude oil and foreign currency swap and option contracts to protect its future Canadian dollar earnings and cash flows from the potential adverse impact of low petroleum prices and an unfavourable Canadian/U.S. dollar exchange rate. These contracts reduce fluctuations in sales revenues by locking in fixed prices, or a range of fixed prices, and exchange rates on the portion of its crude oil sales covered by the contracts. The company also enters into crude oil, gasoline and heating oil swap contracts to lock in fixed margins on the portion of refined product sales covered by the contracts. While these contracts reduce the risk of exposure to adverse changes in commodity prices and exchange rates, they also reduce the potential benefit of favourable changes in commodity prices and exchange rates.

The contracts do not require the payment of premiums or cash margin deposits prior to settlement. On settlement, these contracts result in cash receipts or payments by the company for the difference between the contract and market rates for the applicable dollars and volumes hedged during the contract term. Such cash receipts or payments offset corresponding decreases or increases in the company's sales revenues or crude oil purchase costs. For accounting purposes, amounts received or paid on settlement are recorded as part of the related hedged sales or purchase transactions.

Contracts outstanding at December 31 were as follows:

Crude Oil Hedges	Quantity (bbl/day)	Average Price (a) (US$/bbl)	Revenue Hedged (Cdn$millions)	Hedge Period
As at December 31, 2002				
Crude oil swaps	**10 000**	**30**	**57**(c)	**2003**(b)
Crude oil swaps	**15 000**	**24**	**208**(c)	**2003**
Costless collars	**60 000**	**21 - 26**	**726 - 899**(c)	**2003**
Crude oil swaps	**25 000**	**23**	**332**(c)	**2004**
Costless collars	**11 000**	**21 - 24**	**133 - 152**(c)	**2004**
Crude oil swaps	**21 000**	**22**	**266**(c)	**2005**
As at December 31, 2001				
Crude oil swaps	40 576	20	444(d)	2002
Crude oil swaps	424	21	5(c)	2002
Costless collars	43 000	22 - 27	550 - 675(c)	2002
Costless collars	44 000	21 - 26	537 - 665(c)	2003
Costless collars	11 000	21 - 24	134 - 153(c)	2004
Crude oil swaps	15 000	22	192(c)	2005
As at December 31, 2000				
Crude oil swaps	42 710	20	436(d)	2001
Crude oil swaps	4 790	20	52(c)	2001
Costless collars	10 000	26 - 32	142 - 175(c)	2001
Crude oil swaps	41 000	20	426(d)	2002
Costless collars	7 000	22 - 26	84 - 1003(c)	2002

Margin Hedges	Quantity (bbl/day)	Average Margin (US$/bbl)	Margin Hedged(c) (Cdn$ millions)	Hedge Period
Refined product sales and crude purchase swaps				
As at December 31, 2002	**20 700**	**5**	**9**	**2003**(e)
As at December 31, 2001	—	—	—	—
As at December 31, 2000	13 300	5	18	2001(f)

(a) Average price for crude oil swaps is WTI per barrel at Cushing, Oklahoma.
(b) For the period January to April 2003, inclusive. All other crude oil positions are for the full year.
(c) The revenue and margin hedged is translated to Cdn$ at the year-end exchange rate and is subject to change as the Cdn$/US$ exchange rate fluctuates during the hedge period.
(d) The revenue hedged was fixed in Cdn$ as the company had foreign exchange swaps in place for these crude oil swaps.
(e) For the period January and February 2003.
(f) For the period January to June 2001.

Interest Rate Hedges

The company enters into interest rate and cross-currency interest rate swap contracts as part of its risk management strategy to manage its exposure to interest rates. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between the company and investment grade counterparties. The cross-currency swap contracts involve an exchange of Canadian dollar interest payments and U.S. dollar interest payments, and an exchange of Canadian and U.S. dollar principal amounts at the maturity date of the underlying borrowing to which the swaps relate. The differentials on the exchange of periodic interest payments are recognized in the accounts as an adjustment to interest expense.

The notional amounts of interest rate and cross-currency interest rate swap contracts outstanding at December 31, 2002 are detailed in note 4,

Long-term Debt.

Fair Value of Derivative Financial Instruments

The fair value of hedging derivative financial instruments is the estimated amount, based on brokers' quotes, that the company would receive (pay) to terminate the contracts. Such amounts, which also represent the unrecognized and unrecorded gain (loss) on the contracts, were as follows at December 31:

($ millions)	2002	2001
Revenue hedge swaps and options	**(133)**	54
Margin hedge swaps	**1**	(2)
Interest rate and cross-currency interest rate swaps	**35**	4
	(97)	56

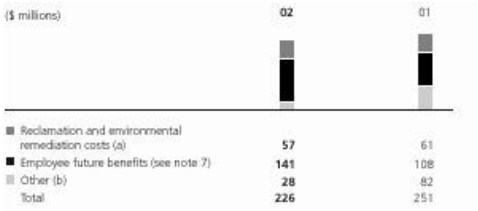
The fair value of the derivative financial instruments related to the company's trading activities are determined based on actively traded, quoted market prices. For the period ended December 31, 2002, gains or losses resulting from trading activities were not significant.

(c) Counterparty Credit Risk

The company may be exposed to certain losses in the event that counterparties to the derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts with positive fair values at the reporting date. The company minimizes this risk by entering into agreements only with investment grade counterparties, and through regular management review of potential exposure to, and credit ratings of, such counterparties. At December 31, the company had exposure to credit risk with counterparties as follows:

($ millions)	2002	2001
Derivative contracts not accounted for as hedges	**28**	12
Unrecognized derivative contracts	**23**	93
	51	105

6. Accrued Liabilities and Other



(a) Reclamation and Environmental Remediation Costs

Total accrued reclamation and environmental remediation costs also include $32 million in current liabilities (2001 —$23 million). Payments during 2002 totalled $15 million (2001 — $28 million; 2000 — $15 million), while expense recorded in 2002 was $20 million (2001 — $15 million; 2000 — $13 million).

(b) Employee and Director Incentive Plans

Included in accrued liabilities and other is accrued compensation expense related to the company's employee long-term incentive plan (see note 11b). Accrued liabilities and other also include accrued compensation expense in the form of deferred share units received under the directors' compensation plan. Accrued directors' compensation expense is not significant.

7. Employee Future Benefits

Suncor employees are eligible to receive certain pension, health care and insurance benefits when they retire. The related ***Benefit Obligation*** *or commitment that Suncor had to employees and retirees at December 31, 2002 was $586 million.*

As required by government regulations and plan performance, Suncor sets aside funds, with an independent trustee, to meet certain of these obligations. At the end of December, 2002, Plan Assets to meet the ***Benefit Obligation*** *were $273 million.*

The excess of the ***Benefit Obligation*** *over Plan Assets of $313 million represents the Net Unfunded Obligation.*

See below for more technical details and amounts.

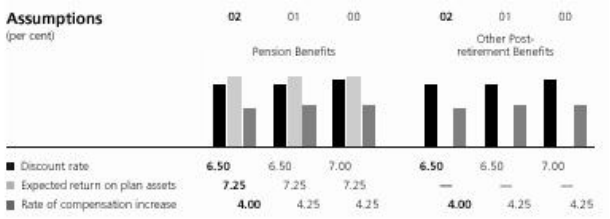
Defined Benefit Pension Plans and Other Post-retirement Benefits

The company's defined benefit pension plans provide a pension benefit at retirement based on years of service and final average earnings. These obligations are met through a funded registered retirement plan and through unfunded, unregistered supplementary benefits that are paid directly to recipients. Company contributions to the funded plan are deposited with an independent trustee who acts as custodian of the funded pension plan assets, as well as the disbursing agent of the benefits to recipients. Plan assets are managed by an employee pension committee on behalf of beneficiaries. The committee retains independent managers and advisers.

Funding of the registered retirement plan complies with federal and provincial pension legislation that requires an actuarial valuation of the pension funds be performed at least once every three years. As a result of a recent triennial valuation of the registered plan, company funding of current and past service costs for 2003 is anticipated to be $45 million to $50 million (2002 — $14 million).

The company's other post-retirement benefits program, which is unregistered and unfunded, includes certain health care and life insurance benefits provided to retired employees and eligible surviving dependants. Retirees share in the cost of providing these benefits.

The expense and obligations for both funded and unfunded benefits are determined in accordance with Canadian generally accepted accounting principles and actuarial procedures. Obligations are based on the projected benefit method of valuation that includes employee service to date and present pay levels, as well as a projection of salaries and service to retirement. Obligations are based on the following assumptions:



The following table presents information about the funded status of the plans and obligations recognized in the consolidated balance sheets at December 31:

($ millions)	Pension Benefits 2002	Pension Benefits 2001	Other Post-retirement Benefits 2002	Other Post-retirement Benefits 2001
Change in benefit obligation				
Benefit obligation at beginning of year	**461**	404	**93**	79
Service costs	**17**	14	**4**	3
Interest costs	**30**	28	**6**	6
Plan participants' contribution	**4**	3	**—**	—
Amendments	**—**	—	**(34)**	—
Actuarial (gain) loss	**(1)**	34	**30**	7
Benefits paid	**(22)**	(22)	**(2)**	(2)
Benefit obligation at end of year	**489**	461	**97**	93
Change in plan assets (a)				
Fair value of plan assets at beginning of year	**301**	322	**—**	—
Actual (loss) on plan assets	**(24)**	(14)	**—**	—
Employer contribution	**14**	12	**—**	—
Plan participants' contribution	**4**	3	**—**	—
Benefits paid	**(22)**	(22)	**—**	—
Fair value of plan assets at end of year	**273**	301	**—**	—
Net unfunded obligation	**(216)**	(160)	**(97)**	(93)
Items not yet recognized in earnings:				
Unamortized net actuarial loss (b)	**142**	109	**46**	19
Unamortized past service costs (c)	**—**	—	**(34)**	—
Accrued benefit liability	**(74)**	(51)	**(85)**	(74)
Current portion	**(16)**	(15)	**(2)**	(2)
Long-term portion (note 6)	**(58)**	(36)	**(83)**	(72)
	(74)	(51)	**(85)**	(74)

(a) Assets in the pension plan consist of investments in marketable equity securities, government and corporate bonds, and short-term notes. Pension plan assets are not the company's assets and therefore are not included in the consolidated balance sheets.

(b) The unamortized net actuarial loss represents annually calculated differences between actual and projected plan performance. These amounts are amortized as part of the net periodic benefit cost over the expected average remaining service life of employees of 13 years for pension benefits and over the expected average future service life to full eligibility age of 11 years for other post-retirement benefits. As a result of a recent triennial valuation, effective 2003, the expected average remaining service life of employees and the expected average future service life to full eligibility age will be 12 years and 10 years respectively.

(c) Effective April 1, 2003, the company will implement amendments to its existing post-retirement benefits program. Certain of the company's employees and all retirees will continue to receive post-retirement benefits under the current plan provisions. These plan amendments have reduced the company's other post-retirement benefits obligation at December 31, 2002, by $34 million.

The above benefit obligation at year-end includes funded and unfunded plans, as follows:

($ millions)	Pension Benefits 2002	Pension Benefits 2001	Other Post-retirement Benefits 2002	Other Post-retirement Benefits 2001
Funded plan	**423**	377	**—**	—
Unfunded plans	**66**	84	**97**	93
Benefit obligation at end of year	**489**	461	**97**	93

The components of net periodic benefit cost are as follows:

($ millions)	Pension Benefits 2002	2001	2000	Other Post-retirement Benefits 2002	2001	2000
Current service costs	**17**	14	12	**4**	3	3
Interest costs	**30**	28	26	**6**	6	5
Expected return on plan assets (a)	**(22)**	(23)	(22)	**—**	—	—
Amortization of transitional asset	**—**	(8)	(8)	**—**	—	—
Amortization of net actuarial loss	**15**	9	6	**2**	1	1
Net periodic benefit cost	**40**	20	14	**12**	10	9

(a) The expected return on plan assets is the expected long-term rate of return on plan assets for the year based on plan assets at the beginning of the year that have been adjusted on a weighted average basis for contributions and benefit payments expected for the year. The expected return on plan assets is included in the net periodic benefit cost for the year to which it relates, while the difference between it and the actual return realized on plan assets in the same year is amortized over the expected average remaining service life of employees of 13 years for pension benefits, and over the expected average future service life to full eligibility age of 11 years for other post-retirement benefits. As a result of a recent triennial valuation, effective 2003, the expected average remaining service life of employees and the expected average future service life to full eligibility age will be 12 years and 10 years, respectively.

A 1% change in the assumptions at which pension benefits and other post-retirement benefits liabilities could be effectively settled is as follows:

($ millions)	Rate of Return on Plan Assets 1% increase	1% decrease	Discount Rate 1% increase	1% decrease	Rate of Compensation Increase 1% increase	1% decrease
Effect on net periodic benefit cost	(3)	3	(8)	10	4	(3)
Effect on benefit obligation	—	—	(71)	81	18	(16)

In order to measure the expected cost of other post-retirement benefits, a 9% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2002. Based upon recent experience, an assumption of 12% will be used for 2003, and then it is assumed this rate will decrease annually by a rate of 0.5% to 5% for 2017, and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for other post-retirement benefit obligations. A 1% change in assumed health care cost trend rates would have the following effects:

($ millions)	1% increase	1% decrease
Effect on total of service and interest cost components of net periodic post-retirement health care benefit cost	2	(2)
Effect on the health care component of the accumulated post-retirement benefit obligation	9	(8)

Defined Contribution Pension Plan

The company has a defined contribution plan, under which both the company and employees make contributions. Company contributions and related expense totalled $5 million in 2002 (2001 — $4 million; 2000 — $4 million).

8. Income Taxes

The assets and liabilities shown on Suncor's balance sheets are calculated using accounting rules known as generally accepted accounting principles. Suncor's income taxes are calculated according to government tax laws and regulations, which results in different values for certain assets and liabilities for income tax purposes. These differences are known as temporary differences, because eventually these differences will reverse.

The amount shown on the balance sheets as future income taxes represent income taxes that will eventually be payable or recoverable in future years when these temporary differences reverse.

See below for more technical details and amounts.

The provision for income taxes reflects an effective tax rate that differs from the statutory tax rate. A reconciliation of the two rates and the dollar effect is as follows:

($ millions)	2002 Amount	%	2001 Amount	%	2000 Amount	%
Federal tax rate	**435**	**38**	195	38	236	38
Provincial abatement	**(114)**	**(10)**	(51)	(10)	(62)	(10)
Federal surtax	**13**	**1**	6	1	7	1
Provincial tax rates	**150**	**13**	69	14	96	16
Statutory tax and rate	**484**	**42**	219	43	277	45
Add (deduct) the tax effect of:						
Crown royalties	**39**	**3**	48	9	83	13
Resource allowance	**(34)**	**(3)**	(28)	(5)	(45)	(8)
Temporary difference in resource allowance	**(120)**	**(10)**	(49)	(10)	(56)	(9)
Large corporations tax	**17**	**1**	16	3	10	2

Tax rate changes on future income taxes	**(10)**	**(1)**	(52)	(11)	(13)	(2)
Attributed Canadian royalty income	**(2)**	**—**	(6)	(1)	(13)	(2)
Non-deductible foreign expenses	**—**	**—**	(17)	(3)	3	—
Assessments and adjustments	**10**	**1**	(11)	(2)	(3)	—
Other	**(1)**	**—**	5	1	—	—
Income taxes and effective rate	**383**	**33**	125	24	243	39

In 2002 net income tax refunds totalled $8 million (2001 — $23 million payment; 2000 — $22 million payment).

The resource allowance is a federal tax deduction allowed as a proxy for non-deductible provincial Crown royalties. As required by generally accepted accounting principles in Canada, resource allowance is accounted for by adjusting the statutory tax rate by the resource allowance rate (currently 25%) applied to those temporary differences that are factored into the determination of the resource allowance.

For the three years ended December 31, 2002, the resource allowance resulted in a net decrease in the company's effective tax rate due primarily to the difference between depreciation for tax and accounting purposes. To the extent that these temporary differences reverse in future years and are not offset by the effect of new capital expenditures, the company's effective tax rate will increase.

At December 31, future income taxes are comprised of the following:

	2002		2001	
($ millions)	**Current**	**Non-current**	**Current**	**Non-current**
Future income tax assets:				
Employee future benefits	**4**	**48**	4	30
Reclamation and environmental remediation costs	**10**	**17**	8	19
Alberta royalties	**—**	**43**	—	44
Employee incentive plans	**—**	**16**	—	29
Inventories	**18**	**—**	11	—
Other	**6**	**11**	6	10
	38	**135**	29	132
Future income tax liabilities:				
Depreciation	**—**	**1 473**	—	1 105
Overburden removal costs	**—**	**20**	—	30
Maintenance shutdown costs	**—**	**15**	—	10
Inventories	**—**	**—**	10	—
Other	**10**	**8**	18	32
	10	**1 516**	28	1 177

9. Commitments and Contingencies

(a) Operating Commitments

In order to ensure continued availability of, and access to, facilities and services to meet its operational requirements, the company enters into transportation service agreements for pipeline capacity and energy services agreements as well as non-cancellable operating leases for service stations, office space and other property and equipment. Under contracts existing at December 31, 2002, future minimum amounts payable under these leases and agreements were as follows:

($ millions)	**Pipeline Capacity and Energy Services (a)**	**Operating Leases**
2003	162	54
2004	161	46
2005	167	39
2006	176	34
2007	177	22
Later years	4 108	61
	4 951	256

(a) Includes annual tolls payable under a transportation service agreement with a major pipeline company to use a portion of its pipeline capacity and tankage for the shipment of crude oil from Fort McMurray to Hardisty, Alberta. The agreement commenced in 1999 and extends to 2028. As the initial shipper on the pipeline, Suncor's tolls payable under the agreement could be subject to annual adjustments.

To meet the energy needs of its oil sands operation, Suncor has a commitment under long-term energy agreements to obtain a portion of the power and all of the steam generated by a cogeneration facility owned by a major energy company. Since October 1999, this company has managed the operations of Suncor's existing energy services facility.

(b) Contingencies

The company is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the accrual of estimated reclamation and environmental remediation costs. These costs are accrued at the company's Natural Gas and Oil Sands operations on the unit of production basis. A provision is not made for currently operated facilities such as the Oil Sands processing facilities, the Sarnia refinery and service stations until cessation of operations and completion of site investigations. Any changes in environmental remediation estimates (net of estimated gains on sale of sites) will affect future earnings. These estimates could change significantly based upon such factors as operating experience, changes in legislation and regulations and cost.

To mitigate its exposure to property and business interruption losses, the company has purchased insurance policies with a combined coverage of up to US$1,150 million, net of deductible amounts. The policies stipulate a property loss deductible of US$10 million per incident, and a business

interruption loss deductible per incident, based on the greater of US$50 million or 30 days of gross earnings lost (as defined in the respective insurance policies). Gross earnings can be influenced by such factors as production levels and commodity prices.

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The company believes that any liabilities that might arise pertaining to such matters would not be expected to have a material effect on the company's consolidated financial position.

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and to be funded from the company's cash provided from operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, the impact may be material.

(c) Special Purpose Entities and Guarantees

At December 31, 2002, the company had various off-balance sheet arrangements with Special Purpose Entities and indemnification agreements with third parties as described below.

The company has a securitization program in place to sell, on a revolving, fully serviced and limited recourse basis, up to $170 million of accounts receivable having a maturity of 45 days or less to a third party. The third party is a multiple party securitization vehicle that provides funding for numerous asset pools. As at December 31, 2002, $170 million in outstanding accounts receivable had been sold under the program. Under the recourse provisions, the company will provide indemnification against credit losses to a maximum of $53 million. A liability has not been recorded for this indemnification as the company believes it has no significant exposure to credit losses. Proceeds received from new securitizations and proceeds from collections reinvested in securitizations on a revolving basis for the year ended December 31, 2002, were approximately $4 million and $2,421 million, respectively. The company recorded an after-tax loss of approximately $3 million on the securitization program in each of the last three years.

In 1999, the company sold 2,130,000 barrels of its crude oil inventory for $49 million to a third party while retaining the right to use the inventory for its operations through a usage agreement for a five-year period. The third party's sole asset is the inventory sold to it by the company. The company pays an annual usage fee of $7 million to the third party and receives a $4 million annual storage fee. The company has the right, but is not obligated, to repurchase the inventory at the spot price at the end of the agreement in 2004. In order to reduce the exposure to the spot price should it elect to repurchase the inventory, the company had, at December 31, 2002, crude oil and U.S. dollar swap contracts fixing the purchase price of the crude oil at Cdn$49 million.

In 1999, the company entered into an equipment sale and leaseback arrangement with a third party for proceeds of $30 million. The third party's sole asset is the equipment sold to it and leased back by the company. The initial lease term covers a period of seven years and is accounted for as an operating lease. The company has provided a residual value guarantee on the equipment of up to $7 million should it elect not to repurchase the equipment at the end of the lease term. An early termination purchase option allows for the repurchase of the equipment at specified dates in 2003, 2004 and 2005. Had the company elected to terminate the lease at December 31, 2002, the total cost would have been $32 million. Lease payments by the company in each of the last three years were $2 million per year.

The company has agreed to indemnify lenders of the 9.125% preferred securities, the 7.15% notes and the company's credit facilities (see note 4) for added costs relating to taxes, assessments or other government charges or conditions, including any required withholding amounts. Similar indemnity terms apply to the receivables securitization program, the crude oil inventory monetization agreement and certain facility and equipment leases.

There is no limit to the maximum amount payable under the indemnification agreements described above. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, Suncor has the option to redeem or terminate these contracts if additional costs are incurred.

10. Preferred Securities

During 1999, the company completed a Canadian offering of $276 million of 9.05% preferred securities and a U.S. offering of US$162.5 million of 9.125% preferred securities for net proceeds of Cdn$507 million after issue costs of $17 million ($10 million after income taxes). The preferred securities are comprised of unsecured junior subordinated debentures, due in 2048 and redeemable at the company's option on or after March 15, 2004 for proceeds equal to the original principal amount of the preferred securities plus any accrued and unpaid interest as at the date of redemption. Subject to certain conditions, the company has the right to defer payment of interest on the securities for up to 20 consecutive quarterly periods. Deferred interest and principal amounts are payable in cash, or, at the option of the company, from the proceeds on the sale of equity securities of the company delivered to the trustee of the preferred securities. Accordingly, the preferred securities are classified as share capital in the consolidated balance sheet and the interest distributions thereon, net of income taxes, are classified as dividends. Proceeds from the offerings were used to repay commercial paper debt.

In 2002, dividends of $48 million were paid on the preferred securities (2001 — $48 million; 2000 — $47 million).

11. Share Capital

(a) Authorized:

Common Shares

The company is authorized to issue an unlimited number of common shares without nominal or par value.

Preferred Shares

The company is authorized to issue an unlimited number of preferred shares in series, without nominal or par value.

(b) Issued:

The number of common shares and common share options outstanding, common share prices and per share calculations, for both current and prior periods, reflect a two-for-one split of the company's common shares during 2002.

	Common Shares

($ millions)	Number	Amount
Balance as at December 31, 2000	443 801 158	537
Issued for cash under stock option plans	2 096 138	15
Issued under dividend reinvestment plan	59 194	3
Balance as at December 31, 2001	445 956 490	555
Issued for cash under stock option plans	1 776 433	19
Issued under employee long-term incentive plan	1 089 888	—
Issued under dividend reinvestment plan	148 732	4
Balance as at December 31, 2002	**448 971 543**	**578**

Common Share Options

A stock option gives the holder the right, but not the obligation, to purchase common shares at a predetermined price over a specified period of time.

After the date of grant, employees that hold options must earn the rights to exercise them. This is done by the employee fulfilling a time requirement for service to the company, and with respect to certain options, subject to accelerated vesting should the company meet predetermined performance criteria. Once this right has been earned, these options are considered vested. Options granted to non-employee directors vest and are exercisable immediately.

The predetermined price at which an option can be exercised is generally equal to or greater than the market price of the common shares on the date the options are granted.

See below for more technical details and amounts on the company's stock option plans:

(i) EXECUTIVE STOCK PLAN Under this plan, the company granted 1,802,650 common share options in 2002 to non-employee directors and certain executives and other senior employees of the company. The exercise price of an option is equal to the market value of the common shares at the date of grant. Options granted to non-employee directors have a 10-year life and are exercisable immediately. Options granted to employees have a 10-year life and vest annually over a three-year period.

(ii) EMPLOYEE LONG-TERM INCENTIVE PLAN Suncor's employee long-term incentive plan was adopted in 1997 and matured on April 1, 2002. At maturity, employees received 1,089,888 common shares from treasury for nil cash consideration, along with aggregate cash payments of $34 million. In addition, 2,131,517 common share options, previously granted to senior employees, vested and became exercisable. The company expensed the cash payments to employees of $34 million as pretax compensation expense over the five-year life of the plan. No compensation expense was recorded related to the employees' receipt of common shares from treasury as these common shares were treated as stock option grants.

Concurrently, 1,461,886 deferred share units (DSUs) with a cash settlement value of $42 million, which had previously been granted to certain executives, vested. These executives also received cash payments of $44 million. As of April 1, 2002, the company had recorded total pretax compensation expense of $86 million related to the executive portion of the company's long-term incentive plan over the five-year life of the plan.

DSUs are only redeemable at the time a unitholder ceases employment. Subsequent to April 1, 2002, 220,347 DSUs were redeemed for cash consideration of $6 million, resulting in total cash payments made to executives during 2002 of $50 million. Over time, DSU unitholders are entitled to receive additional DSUs equivalent in value to future notional dividend reinvestments. From April to December of 2002, an additional 6,495 DSUs were issued pursuant to this dividend reinvestment feature.

Final DSU redemption amounts are subject to change depending on the company's share price at the time of exercise. Accordingly, the company revalues the DSUs on each reporting date, with any changes in value recorded as an adjustment to compensation expense in the period. As at December 31, 2002, 1,248,034 DSUs were outstanding with a total liability of $31 million, of which $27 million was classified as long-term (see note 6).

During 2002, total pretax compensation expense recorded under the company's long-term incentive plans to employees, senior management and executives was $10 million (2001 — $42 million; 2000 — $32 million). For the five-year period ended April 1, 2002, total pretax compensation expense was $120 million.

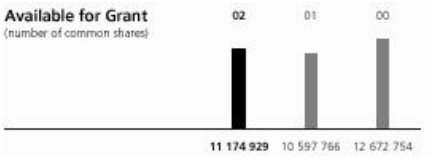
(iii) SUNSHARE PERFORMANCE STOCK OPTION PLAN During 2002, the company granted 8,937,992 options to all eligible permanent full-time and part-time employees, both executive and non-executive, under its new employee stock option incentive plan ("SunShare"). Under SunShare, meeting specified performance targets may accelerate the vesting of some or all options, such that 20% of outstanding options may vest as early as 2004, up to an additional 20% of outstanding options may vest as early as 2005 and the remaining 60% of outstanding options may vest on April 30, 2008. All unvested options which have not previously expired or been cancelled will automatically vest on January 1, 2012.

The following tables cover all common share options granted by the company for the years indicated:

	Number	Exercise Prices	Weighted-average Exercise Price
Outstanding, December 31, 1999	11 715 972	2.38 - 15.09	9.01
Granted	1 900 032	13.04 - 19.28	15.65
Exercised	(1 474 404)	2.38 - 12.28	6.29
Cancelled	(419 850)	10.13 - 16.52	13.02
Outstanding, December 31, 2000	11 721 750	2.38 - 19.28	10.28
Granted	2 180 720	15.94 - 21.35	17.63
Exercised	(2 028 668)	2.38 - 16.48	7.30
Cancelled	(105 732)	10.13 - 20.20	14.21
Outstanding, December 31, 2001	11 768 070	2.38 - 21.35	12.12
Granted	10 740 642	23.93 - 28.14	27.08

Exercised	(1 776 433)	2.38 - 17.45	10.42
Cancelled	(406 028)	13.04 - 27.65	26.48
Outstanding, December 31, 2002	**20 326 251**	**3.80 - 28.14**	**19.89**
Exercisable, December 31, 2002	**8 580 913**	**3.80 - 28.14**	**11.85**

Common shares authorized for issuance by the Board of Directors that remain available for the granting of future options, at December 31:



The following table is an analysis of outstanding and exercisable common share options as at December 31, 2002:

	Outstanding			Exercisable	
Exercise Prices	**Number**	**Weighted-average Remaining Contractual Life**	**Weighted-average Exercise Price**	**Number**	**Weighted-average Exercise Price**
3.80 - 7.85	2 248 328	3 years	6.37	2 248 328	6.37
10.13 - 14.41	4 183 137	5 years	11.93	4 183 130	11.93
15.09 - 19.28	3 435 486	8 years	16.70	1 888 504	16.48
20.20 - 28.14	10 459 300	9 years	27.02	260 951	24.35
Total	20 326 251	7 years	19.89	8 580 913	11.85

(iv) FAIR VALUE OF OPTIONS GRANTED The fair values of all common share options granted are estimated as at the grant date using the Black-Scholes option-pricing model. The weighted-average fair values of the options granted during the year and the weighted-average assumptions used in their determination are as noted below:

	2002	2001	2000
Annual dividend per share	**$ 0.17**	$ 0.17	$ 0.17
Risk-free interest rate	**5.39%**	5.07%	6.45%
Expected life	**8 years**	5 years	7 years
Expected volatility	**31%**	35%	37%
Weighted-average fair value per option	**$ 12.08**	$ 6.41	$ 7.12

The company does not recognize any compensation costs related to stock options granted to employees and non-employee directors. Had compensation cost been determined based on the fair values at the grant dates, the cost of which is recognized over the vesting periods of the options granted, the company's net earnings and earnings per share would have been reduced to the amounts below:

($ millions, except per share amounts)	**2002**	**2001**	**2000**
Net earnings attributable to common shareholders — as reported	**734**	351	345
Less: compensation cost under the fair value method	**32**	9	7
Pro forma net earnings attributable to common shareholders	**702**	342	338
Basic earnings per share			
As reported	**1.64**	0.79	0.78
Pro forma	**1.57**	0.77	0.76
Diluted earnings per share			
As reported	**1.61**	0.78	0.77
Pro forma	**1.54**	0.76	0.75

12. Earnings Per Common Share

The following is a reconciliation of basic and diluted earnings per common share:

($ millions)	**2002**	**2001**	**2000**
Net earnings attributable to common shareholders	**734**	351	345
Dividends on preferred securities, net of tax	**28**	—(a)	—(a)
Revaluation of US$ preferred securities, net of tax	**(1)**	—(a)	—(a)
Adjusted net earnings attributable to common shareholders	**761**	351	345
(millions of common shares)			
Weighted-average number of common shares	**448**	445	443
Dilutive securities:			
Options issued under stock-based compensation plans	**5**	6	4
Redemption of preferred securities by the issuance of common shares	**20**	—(a)	—(a)
Weighted-average number of diluted common shares	**473**	451	447

(dollars per common share)			
Basic earnings per share (b)	**1.64**	0.79	0.78
Diluted earnings per share	**1.61(c)**	0.78(a)	0.77(a)

Common share and earnings per common share amounts in the above table reflect a two-for-one share split effective May 15, 2002.

Note: An option will have a dilutive effect under the treasury stock method only when the average market price of the common stock during the period exceeds the exercise price of the option.

(a) For the years ended December 31, 2001 and 2000, diluted earnings per share is the net earnings attributable to common shareholders divided by the weighted-average number of diluted common shares. Dividends on preferred securities, the revaluation of US$ preferred securities and the redemption of preferred securities by the issuance of common shares have an anti-dilutive impact, therefore they are not included in the calculation of diluted earnings per share.

(b) Basic earnings per share is the net earnings attributable to common shareholders divided by the weighted-average number of common shares.

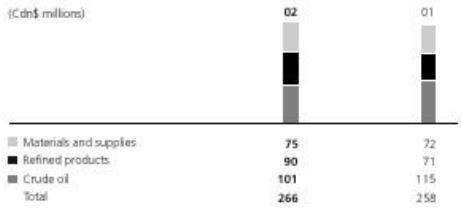
(c) Diluted earnings per share is the adjusted net earnings attributable to common shareholders, divided by the weighted-average number of diluted common shares.

13. Financing Expenses

($ millions)	2002	2001	2000
Interest on debt	**155**	143	112
Capitalized interest	**(22)**	(125)	(104)
Net interest expense	**133**	18	8
Foreign exchange (gain) on long-term debt and other	**(9)**	(2)	—
Total financing expenses	**124**	16	8

Cash interest payments in 2002 totalled $134 million (2001 — $129 million; 2000 — $104 million).

14. Inventories



The replacement cost at December 31, 2002, of crude oil and refined product inventories valued at LIFO exceeded their carrying value by $84 million (2001 — $5 million).

15. Accounting for Intersegment Revenues

In 2001, the company changed the methodology of accounting for sales from its upstream operations to its downstream operations from a deeming concept to one based on actual product shipments.

The impact of this prospective change in methodology on 2002 was to increase both operating revenues and purchases of crude oil and products by $1,164 million (2001 — $473 million). There was no impact on consolidated and segmented net earnings.

16. Sales of the Retail Natural Gas Marketing Business and Oil Shale Project

(a) In 2002, the company sold its retail natural gas marketing business in the Energy Marketing and Refining segment for cash consideration of $62 million, net of related closing costs and adjustments of $4 million, resulting in an after-tax gain of $35 million.

(b) In 2001, the company sold its interest in the Stuart Oil Shale Project for consideration of $5 million comprised of common shares and share options in SPP. During 2002, the company reduced the carrying value of the SPP shares by $1 million (2001 — $3 million) to reflect the decline in their value.

17. Related Party Transactions

The following table summarizes the company's related party transactions before eliminations for the year. These transactions are in the normal course of operations and have been carried out on the same terms as would apply with unrelated parties.

($ millions)	2002	2001	2000
Operating revenues			
Sales to Energy Marketing and Refining segment joint ventures:			
Refined products	**612**	602	600
Petrochemicals	**142**	131	128

The company has exclusive supply agreements with two Energy Marketing and Refining segment joint ventures for the sale of refined products. The company also has a non-exclusive supply agreement with an Energy Marketing and Refining segment joint venture for the sale of petrochemicals.

Sales to and balances with Energy Marketing and Refining segment joint ventures are established and agreed to by the related parties and approximate fair value.

At December 31, 2002, amounts due from Energy Marketing and Refining segment joint ventures were $46 million (2001 — $33 million).

18. Supplemental Information

($ millions)	2002	2001	2000
Export sales (a)	**501**	590	478
Exploration expenses			
Geological and geophysical	**13**	11	10
Other	**2**	1	2
Cash costs	**15**	12	12
Dry hole costs	**11**	10	41
Cash and dry hole costs (b)	**26**	22	53
Leasehold impairment (c)	**10**	9	10
	36	31	63
Taxes other than income taxes			
Excise taxes (d)	**340**	343	336
Production, property and other taxes	**34**	24	25
	374	367	361
Allowance for doubtful accounts	**3**	3	

(a) Sales of crude oil, natural gas and refined products to customers in the United States and sales of petrochemicals to customers in the United States and Europe.

(b) Included in exploration expenses in the Consolidated Statements of Earnings.

(c) Included in depreciation, depletion and amortization in the Consolidated Statements of Earnings.

(d) Included in operating revenues in the Consolidated Statements of Earnings.

In 2000, the carrying values of certain assets of the company's Natural Gas business were written down to their net estimated recoverable amount and a provision for estimated restructuring costs was recorded. During 2001, some of these properties that were previously written down were sold and provisions for estimated restructuring costs were revised to reflect increased employee termination costs. The impact of these adjustments on 2002 is nil (2001 — increased net earnings by $1 million; 2000 — decreased net earnings by $30 million).

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

The consolidated financial statements have been prepared in accordance with Canadian GAAP. The application of United States GAAP (U.S. GAAP) would have the following effects on earnings and comprehensive income as reported:

($ millions)	Notes	2002	2001	2000
Net earnings as reported, Canadian GAAP		**761**	388	377
Adjustments net of applicable income taxes				
Stock-based compensation	(b)	**(12)**	(14)	(22)
Preferred securities	(c)	**(29)**	(27)	(22)
Start-up costs	(d)	**—**	10	8
Income taxes	(e)	**—**	6	(6)
Write-off of oil shale assets	(f)	**—**	64	(64)
Derivatives and hedging activities	(a)	**6**	(55)	—
Cumulative effect of change in accounting principles	(a)	**—**	47	—
Net (earnings) loss attributable to discontinued operations	(g)	**(56)**	5	5
Net earnings from continuing operations, U.S. GAAP		**670**	424	276
Net earnings (loss) from discontinued operations, U.S. GAAP	(g)	**56**	(5)	(5)
Minimum pension liability, net of income taxes of $10 (2001 — $11; 2000 — $1)	(h)	**(20)**	(26)	(2)
Derivatives and hedging activities, net of income taxes of $54 (2001 — $16)	(a)	**(118)**	29	—
Comprehensive income, U.S. GAAP		**588**	422	269
Per common share (dollars)				
Net earnings per share from continuing operations				
Basic		**1.50**	0.95	0.62
Diluted		**1.47**	0.94	0.62
Net earnings per share from discontinued operations				
Basic		**0.12**	(0.01)	(0.01)
Diluted		**0.12**	(0.01)	(0.01)

The application of U.S. GAAP would have the following effects on the consolidated balance sheets as reported:

($ millions)	Notes	2002 As Reported	2002 U.S. GAAP	2001 As Reported	2001 U.S. GAAP
Total current assets	(a)	**722**	**767**	622	694
Property, plant and equipment, net	(c)	**7 641**	**7 674**	7 141	7 174
Deferred charges and other	(a,c,h)	**185**	**231**	199	210
Future income taxes	(a,c,h)	**135**	**165**	132	159
Total assets		**8 683**	**8 837**	8 094	8 237
Total current liabilities	(a)	**797**	**933**	773	806
Long-term debt	(a,c)	**2 686**	**3 251**	3 113	3 649
Accrued liabilities and other	(b,h)	**226**	**306**	251	336
Future income taxes	(a,c)	**1 516**	**1 539**	1 177	1 220
Preferred securities	(c)	**523**	**—**	525	—
Share capital and additional paid-in capital	(b)	**578**	**626**	555	555
Retained earnings		**2 357**	**2 319**	1 700	1 670
Accumulated other comprehensive income	(a,h)	**—**	**(137)**	—	1
Total liabilities and shareholders' equity		**8 683**	**8 837**	8 094	8 237

(a) Derivative Financial Instruments

The company accounts for its derivative financial instruments under Canadian GAAP as described in note 5 to the Consolidated Financial Statements. Statement 133 "Accounting for Derivative Instruments and Hedging Activities", as amended by Statement 138, (the Standards), establishes U.S. GAAP accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. Generally, all derivatives, whether designated in hedging relationships or not, and excluding normal purchases and normal sales, are required to be recorded on the balance sheet at fair value. If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk, are recognized in the statements of earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income ("OCI") and are recognized in the statements of earnings when the hedged item is recognized. Accordingly, ineffective portions of changes in the fair value of hedging instruments are recognized in earnings immediately for both fair value and cash flow hedges. Gains or losses arising from hedging activities, including the ineffective portion, are reported in the same earnings statement caption as the hedged item. Gains or losses from derivative instruments for which hedge accounting is not applied are reported in other income.

Adoption of the Standards

For U.S. GAAP purposes, the company's adoption of Statement 133 effective January 1, 2001 would have increased assets by $176 million, increased liabilities by $302 million, decreased OCI by $173 million, net of income taxes of $87 million, and increased net income due to the cumulative effect of a change in accounting principles by $47 million, net of income taxes of $28 million.

Commodity Price Risk

The company periodically enters into derivative financial instrument contracts such as forwards, futures, swaps and options to hedge against the potential adverse impact of market prices for its petroleum and natural gas products. The company manages its Canadian dollar crude price exposure by entering into U.S. dollar WTI derivative transactions and in some instances combines U.S. dollar WTI derivative transactions and Canadian/U.S. foreign exchange derivative contracts. As at December 31, 2002 the company had hedged a portion of its future cash flows subject to commodity price risk for up to three years.

Interest Rate Risk

The company periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to minimize exposure to changes in cash flows of interest-bearing debt. At December 31, 2002 the company has interest rate derivatives classified as cash flow hedges outstanding for one year and fair value hedges outstanding for nine years.

During 2001, the company terminated the cross-currency interest rate swaps related to its Series C 7.4% Debentures. For Canadian GAAP purposes, the resulting gain of $4 million, net of income taxes of $2 million, has been deferred and is being amortized over the term to maturity of the Debentures, resulting in a decrease in interest expense during the year ended December 31, 2002 of $1 million, net of income taxes of $1 million. For U.S. GAAP purposes, the entire $4 million gain would have been recognized during 2001.

Non-designated Hedging Instruments

In 1999, the company sold inventory and subsequently entered into a derivative contract with an option to repurchase the inventory at the end of five years. The company realized an economic benefit as a result of liquidating a portion of its inventory. The derivative did not qualify for hedge accounting as the company does not have purchase price risk associated with the repurchase of the inventory. This derivative does not represent a U.S. GAAP difference as the company records this derivative at fair value for Canadian purposes.

During the fourth quarter of 2001, the company made a payment of $29 million to terminate a long-term natural gas contract. The contract had been designated as a hedge under Canadian GAAP, and the resulting settlement loss of $18 million, net of income taxes of $11 million, was to be deferred and recognized as the hedged item was settled. During 2002, in connection with the sale of the company's retail natural gas marketing business (see note 19g), the company disposed of the related hedged item. Accordingly, for Canadian GAAP purposes, the company recognized the entire settlement loss of $18 million during 2002. For U.S. GAAP purposes, the long-term contract would have been designated as a normal purchase and sale transaction, and the after-tax loss of $18 million would have been recognized in 2001 on the initial settlement of the contract.

The company has entered into a cross-currency interest rate swap related to US$126 million of variable rate debt. Although the swap transaction could have qualified as a fair value hedge of the related foreign currency risk had it been designated as such, the company chose not to designate it. Accordingly, the company has valued the swap at fair value and the debt has been revalued at the rate in effect at the related balance sheet date. Had the swap been designated as a fair hedge, the net effect on the company's net income would have been the same.

Accumulated OCI

A reconciliation of changes in accumulated OCI to derivative hedging activities for the years ended December 31 is as follows:

($ millions)	2002	2001
Accumulated OCI attributable to derivatives and hedging activities, beginning of period, net of income taxes of $13	**29**	—
Net hedging losses arising from implementation of the Standards, net of income taxes of $87	**—**	(173)
Current period net hedging losses arising from cash flow hedges, net of income taxes of $57 (2001 — $38)	**(123)**	79
Net hedging losses at beginning of the period reclassified to earnings during the period, net of income taxes of $3 (2001 — $62)	**5**	123
Accumulated OCI attributable to derivatives and hedging activities, end of period, net of income taxes of $41 (2001 — $13)	**(89)**	29

During the year ended December 31, 2002, assets increased by $87 million and liabilities increased by $178 million as a result of recording all derivative instruments at fair value.

The loss associated with hedge ineffectiveness on derivative contracts designated as cash flow hedges during the period was $19 million, net of income taxes of $9 million (2001 — $32 million, net of income taxes of $15 million). The company estimates that $72 million of hedging losses will be reclassified from OCI to current period earnings within 2003 as a result of forecasted sales occurring.

(b) Stock-based Compensation

Under Canadian GAAP, compensation expense has not been recognized for common share options granted in connection with the company's new SunShare long-term incentive plan. Under U.S. GAAP, certain of these options would have been accounted for using the variable method of accounting for employee stock compensation. As at December 31, 2002 no compensation expense would have been recognized on these options for U.S. GAAP purposes.

Under Canadian GAAP, compensation expense has not been recognized for common share options, including the common shares received by employees as described in note 11b under the company's previous long-term employee incentive plan that matured April 1, 2002. Under U.S. GAAP, compensation expense would have been recognized ratably over the life of the incentive plan for these options and common shares. For the year ended December 31, 2002, net earnings would have been reduced by $12 million (2001 — $14 million; 2000 — $22 million). As settlement of the incentive plan was made through issuance of options and common stock from treasury, share capital and additional paid-in capital was increased by $48 million.

Under Canadian GAAP, had the company accounted for its stock options using the fair value method, pro forma net earnings and pro forma basic earnings per share for the year ended December 31, 2002 would have been reduced by $32 million (2001 — $9 million; 2000 — $7 million) and $0.07 per share (2001 — $0.02; 2000 — $0.02), respectively. Under U.S. GAAP, had the company accounted for its options using the fair value method (excluding the SunShare and long-term employee incentive options identified above), pro forma net earnings and pro forma basic earnings per share for the year ended December 31, 2002 would have been reduced by $24 million (2001 — $9 million; 2000 — $7 million) and $0.05 per share (2001 — $0.02; 2000 — $0.02), respectively.

(c) Preferred Securities

Under Canadian GAAP, preferred securities are classified as share capital and the interest distributions thereon, net of income taxes, are accounted for as dividends. Under U.S. GAAP, the preferred securities would have been classified as long-term debt and the interest distributions thereon would have been accounted for as financing expenses. Preferred securities denominated in U.S. dollars of US$ 163 million would have been revalued at the rate in effect at the related balance sheet date, with any foreign exchange gains (losses) recognized in the statements of earnings. Further, under U.S. GAAP the interest distributions would have been eligible for interest capitalization.

Under Canadian GAAP, issue costs of the preferred securities, net of the related income tax credits, are charged against share capital. Under U.S. GAAP, these issue costs would have been deferred and amortized to earnings over the term of the related long-term debt.

The impact of these differences would have reduced net earnings for U.S. GAAP purposes for the year ended December 31, 2002 by $29 million, net of income taxes of $20 million (2001 — $27 million, net of income taxes of $18 million; 2000 — $22 million, net of income taxes of $17 million).

Under Canadian GAAP, the 2002 interest distributions on the preferred securities for the year ended December 31, 2002 of $48 million (2001 — $48 million; 2000 — $47 million) are classified as financing activities in the consolidated statements of cash flows. Under U.S. GAAP, the interest distributions and the amortization of issue costs for the year ended December 31, 2002 of $3 million (2001 — $3 million; 2000 — $7 million) would have been classified as operating activities.

The preferred securities, which are publicly traded, had a fair value, based on quoted market prices, of $568 million at December 31, 2002 (2001 — $575 million; 2000 — $544 million).

(d) Start-up Costs

In 2001, under Canadian GAAP, all remaining capitalized start-up costs associated with the Stuart Oil Shale Project were written down. Under U.S. GAAP, these start-up costs would have been fully expensed in 1999. As a result, net earnings for U.S. GAAP purposes for 2001 would have been increased by $10 million, net of income taxes of $7 million (2000 — increased net earnings by $8 million, net of income taxes of $6 million).

(e) Income Taxes

Under Canadian GAAP, changes in tax laws and rates are recognized when they are considered substantially enacted, whereas under U.S. GAAP, changes in tax laws and rates are only considered after they have been enacted into law. The impact of this GAAP difference would have been to increase U.S. GAAP net earnings for the year ended December 31, 2001 by $6 million (2000 — decrease net earnings by $6 million).

(f) Asset Impairment

Under Canadian GAAP, the company reduced the carrying amount of its interest in the Stuart Oil Shale Project in 2000, based on a non-

discounted cash flow analysis. Had the carrying amount been determined using a discounted cash flow analysis as required under U.S. GAAP, an additional write-down of $64 million, net of income taxes of $55 million, would have been recorded in 2000. Effective April 5, 2001, the company sold its interest in the project. Due to the difference in determining the carrying value of the project for Canadian and U.S. GAAP purposes in 2000, net earnings for U.S. GAAP purposes for the year ended December 31, 2001 would have increased by $64 million.

(g) Discontinued Operations

During 2002, the company disposed of its retail natural gas marketing business for net proceeds of $62 million, and recognized a $35 million after-tax gain on the sale for Canadian GAAP purposes. The retail natural gas marketing business was not considered significant to the company's overall business operations, and was not classified as a business segment for the purposes of discontinued operations reporting. Accordingly, financial results of the retail natural gas marketing business were not segregated from the financial results of the company's other operations prior to the date of disposal of the business.

For U.S. GAAP purposes, the company would have adopted Statement 144 "Accounting for the Impairment and Disposal of Long-Lived Assets," effective January 1, 2002. For the purposes of Statement 144, the retail natural gas marketing business would have been considered a distinguishable component of the company, and reflected as a discontinued operation for the three years ended December 31, 2002. For segmented reporting purposes, the retail natural gas marketing business was included in the Energy Marketing and Refining operating segment in 2002, 2001 and 2000.

Selected financial information regarding the discontinued retail natural gas marketing business for U.S. GAAP purposes is as follows for the years ended December 31:

($ millions)	2002	2001	2000
Revenues from discontinued operations	**81**	196	116
Income (loss) from discontinued operations, net of income taxes of $4 (2001 — $3; 2000 — $3)	**8**	(5)	(5)
Gain on disposal of discontinued operations, net of income taxes of $10	**48**	—	—

Assets and liabilities related to the discontinued operations as at December 31 were comprised as follows:

($ millions)	2002	2001
Accounts receivable	**—**	20
Accounts payable	**—**	54

(h) Minimum Pension Liability

Under U.S. GAAP, recognition of an additional minimum pension liability is required when the accumulated benefit obligation exceeds the fair value of plan assets to the extent that such excess is greater than accrued pension costs otherwise recorded. No such adjustment is required under Canadian GAAP.

Under U.S. GAAP, at December 31, 2002, the company would have recognized a minimum pension liability of $80 million (2001 — $52 million; 2000 — $3 million), an intangible asset of $10 million (2001 — $12 million; 2000 — nil) and other comprehensive loss of $48 million, net of income taxes of $22 million (2001 — $28 million, net of income taxes of $12 million). Other comprehensive income for the year ended December 31, 2002, would have been reduced by $20 million, net of income taxes of $10 million (2001 — $26 million, net of income taxes of $11 million; 2000 — $2 million, net of income taxes of $1 million).

(i) Shipping and Handling Costs

The company reports upstream shipping and handling costs billed to customers as a reduction of operating revenues. Under U.S. GAAP, amounts billed to customers for shipping and handling are classified as revenues. The related shipping and handling costs are classified as expenses.

This impact is one of reclassification only and does not affect net earnings. The result would have been to increase operating revenues and operating, selling and general expenses for the year ended December 31, 2002 by $128 million (2001 — $95 million; 2000 — $96 million), respectively.

Recently Issued Accounting Standards

Asset Retirement Obligations

In August 2001, Statement 143, "Accounting for Asset Retirement Obligations," was issued. This statement changes the method and timing of accruing for costs arising from legal obligations associated with the retirement of tangible capital assets and the associated asset retirement costs. The company is continuing to evaluate the U.S. GAAP impact of implementing Statement 143, effective January 1, 2003.

Exit or Disposal Activities

In June 2002, Statement 146, "Accounting for Costs Associated with Exit or Disposal Activities," was issued. Statement 146 supercedes previous accounting guidance, principally Emerging Issues Task Force (EITF) No. 94-3. Statement 146 applies to exit and disposal activities initiated after December 31, 2002 and requires that the fair value of a liability for a cost associated with an exit or disposal activity be recognized in the period in which the liability is incurred. Under EITF 94-3, a liability was to be recognized at the date of the company's commitment to an exit plan. The company is not currently engaged in any exit or disposal activities.

Stock-based Compensation, Transition and Disclosure

Statement 148, "Accounting for Stock-based Compensation, Transition and Disclosure," issued in December 2002, provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. Statement 148 also requires that disclosures of the pro forma effect of using the fair value method be displayed in a tabular format in both annual and interim reports. Statement 148 is effective for the company's 2002 fiscal year. The company has no current plans to adopt the fair value method of accounting for stock-based compensation. The pro forma effect of using the fair value method is disclosed in (b) Stock-based Compensation above.

Variable Interest Entities

Interpretation No. 46 ("FIN 46"), "Consolidation of Variable Interest Entities" (VIE), was issued in January 2003 (see Special Purpose Entities as described in note 9c). FIN 46 requires certain variable interest entities to be consolidated by the primary beneficiary of the entity if the other equity investors do not have a controlling financial interest in, or do not have sufficient equity at risk to allow the entity to finance its activities without

additional subordinated financial support from other parties. FIN 46 is effective for all new variable interest entities created or acquired after January 31, 2003. For variable interest entities created or acquired prior to February 1, 2003, the provisions of FIN 46 must be applied for the company's third quarter 2003 interim report. The company is currently evaluating the effect that possible consolidation of these VIEs may have on its results of operations and financial condition.

EXHIBIT 3

Management's Discussions and Analysis for the fiscal year ended December 31, 2002, dated February 27, 2003

Management's Discussion and Analysis

This Management's Discussion and Analysis contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. See page 38 for additional information. All financial information is reported in Canadian dollars unless noted otherwise. Natural gas converts to crude oil equivalent at a ratio of six thousand cubic feet to one barrel. References to "Suncor" or "the company" mean Suncor Energy Inc., its subsidiaries and joint venture investments, unless the context otherwise requires. "Notes" refers to the notes to Suncor's 2002 Consolidated Financial Statements.

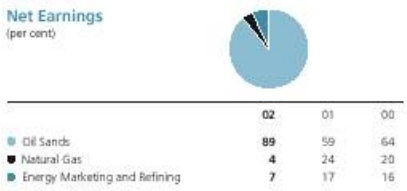
The tables and charts in this document form an integral part of Management's Discussion and Analysis.

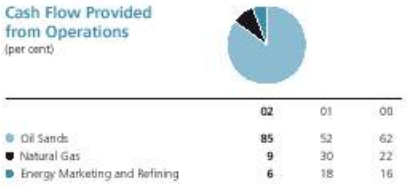
Suncor Overview and Strategic Priorities

Suncor Energy Inc. is an integrated Canadian energy company with its corporate head office located in Calgary, Alberta. Suncor's core business segment, Oil Sands, mines and upgrades oil sands near Fort McMurray, Alberta, to produce refinery feedstock and diesel fuel. Suncor's conventional Natural Gas business (NG) produces natural gas in Western Canada, providing revenues and creating a price hedge against the company's internal natural gas consumption. The Energy Marketing and Refining business (EM&R) refines crude oil and markets finished petroleum products to customers primarily in Ontario and Quebec, including retail customers in Ontario under the Sunoco brand.

Suncor's overall corporate strategy is based on:

- Developing Oil Sands large resource base through mining and in-situ technology.
- Expanding Oil Sands facilities to increase the production of crude oil.
- Controlling costs through a strong operational focus, economies of scale and improved management of engineering, procurement and construction on major projects.
- Reducing risk associated with natural gas price volatility by producing volumes exceeding internal demand.
- Developing new marketing and refining opportunities that further integrate Suncor's upstream and downstream businesses.
- Managing environmental and social performance to earn continued support among community, government and other stakeholders for Suncor's ongoing operations and growth plans.







Net Earnings Components

Year ended December 31

($ millions)	2002	2001	2000
Net earnings before the following items:	**710**	424	414
Natural Gas divestments and restructuring	**—**	5	39
Stuart Oil Shale Project asset write-down	**—**	(3)	(80)

Sale of retail natural gas marketing business	**35**	—	—
Oil Sands project start-up costs(1)	**(2)**	(90)	(9)
Unrealized foreign exchange gains on U.S. dollar denominated long-term debt	**8**	—	—
Impact of income tax rate reductions on opening future tax balances(2)	**10**	52	13
Net earnings	**761**	388	377

Cash Flow Provided from Operations Components
Year ended December 31

($ millions)	2002	2001	2000
Cash flow provided from operations before the following items:	**1 443**	1 061	1 009
Natural Gas divestments and restructuring	**—**	(1)	(9)
Oil Sands project start-up costs and overburden removal(1)	**(3)**	(229)	(42)
Cash flow provided from operations	**1 440**	831	958

(1) Project start-up costs refer to costs associated with Project Millennium in 2000 and 2001 and costs associated with the Firebag In-situ Oil Sands Project in 2002.

(2) See note 8.

The above tables are intended to enhance readers' understanding of some of the factors impacting Suncor's net earnings and cash flow provided from operations. For comparability purposes readers should rely on the reported net earnings and cash flow provided from operations, which are prepared and presented in the Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles.

Earnings Analysis

Net Earnings and Cash Flow Analysis

Net earnings for 2002 increased to $761 million from $388 million in 2001, primarily as a result of higher sales revenues from increased Oil Sands production and improved crude oil price realizations. Net earnings were also positively impacted by reduced project start-up costs at Oil Sands, a gain on the sale of EM&R's retail natural gas marketing business and an unrealized foreign exchange gain. These increases were partially offset by higher crude oil hedging losses and higher cash and non-cash operating expenses, financing costs and higher income taxes. The higher 2002 income taxes are partly a result of the positive earnings impact of enacted rate reductions in 2001 on the company's future income tax liabilities.

Cash flow provided from operations in 2002 was $1.44 billion, compared with $831 million in 2001. The increase was primarily due to the same factors that increased net earnings, excluding the gain on the sale of the company's retail natural gas marketing business. These favourable factors were partially offset by payments under Suncor's long-term employee incentive plan and increased overburden removal expenditures.

Consolidated Financial Results
Year ended December 31

($ millions)	2002	2001	2000
Net earnings	**761**	388	377
Cash flow provided from operations	**1 440**	831	958
Investing activities	**861**	1 680	1 607
Dividends			
Common shares	**77**	75	75
Preferred securities	**48**	48	47
Long-term debt	**2 686**	3 113	2 192
Return on capital employed (%) (1)	**14.6**	17.8	16.6
Return on capital employed (%) (2)	**13.8**	7.5	9.3

(1) Net earnings adjusted for after-tax long-term interest expense, divided by average capital employed. Average capital employed is the total of shareholders' equity and short-term and long-term debt, less capitalized costs of major projects in progress, at the beginning and end of the year, divided by two.

(2) Average capital employed includes capitalized costs related to major projects in progress.

Industry Indicators

(Average for the year unless otherwise noted.)	2002	2001	2000
WTI crude oil US$/barrel at Cushing	**26.10**	25.90	30.25
Canadian 0.3% par crude Cdn$/barrel at Edmonton	**40.75**	39.34	44.56
Light/heavy crude oil differential US$/barrel WTI @ Cushing/Bow River @ Hardisty	**5.95**	9.50	6.85
Natural gas US$/thousand cubic feet (mcf) at Henry Hub	**3.25**	4.40	3.90
Natural gas (Alberta spot) Cdn$/mcf at AECO	**4.05**	6.30	5.00
New York Harbour 3-2–1 crack US$/barrel(1)	**3.35**	4.45	5.45
Refined product demand (Ontario) percentage change over prior year	**0.8(2)**	(2.6)	2.6
Exchange rate: Cdn$:US$	**0.64**	0.64	0.67

(1) New York Harbour 3-2-1 crack is an industry indicator measuring the margin on a barrel of oil for gasoline and distillate. It is calculated by taking two times the New York Harbour gasoline margin plus one times the New York Harbour distillate margin and dividing by three.

(2) Estimate.

Consolidated Earnings Analysis

Revenues were $4.904 billion in 2002, compared to $4.199 billion in 2001. This increase was primarily the result of the following items:

- The **Project Millennium** expansion increased Oil Sands sales to an average 205,300 barrels per day (bpd) from 121,500 bpd in 2001. In addition, expanded hydrotreating capacity increased the sales mix percentage of higher value sweet crude oil and diesel fuel relative to lower value sour crude oil and bitumen to 62/38% in 2002 from 58/42% in 2001. Increased production and a higher value sales mix were the most significant factors in the overall increase in consolidated revenues.

  Project Millennium
  A $3.4 billion expansion of Suncor's Oil Sands mining and upgrading operations was commissioned in December 2001.

- Suncor's overall crude oil price realization increased in 2002, averaging $33.65 per barrel (including the effect of pretax hedging losses of $243 million), compared to $29.17 per barrel in 2001 (including the effect of pretax hedging losses of $224 million). The increase was due to the strengthening of the West Texas Intermediate (WTI) benchmark price during 2002, higher Oil Sands production and the narrowing of sour crude oil and bitumen price differentials.
- Marketing revenue for third party crude oil and bitumen increased to $149 million in 2002 from $99 million in 2001. This marketing is undertaken to increase market intelligence and create new markets and customers for Suncor's proprietary crude oil.

The above factors were partially offset by the following:

- NG revenues in 2002 were $315 million, compared to revenues of $458 million in 2001. Suncor's average natural gas sales price decreased to $3.91 per thousand cubic feet (mcf) in 2002, from $6.09 per mcf in 2001.
- Sales in EM&R were $2.361 billion in 2002, compared to $2.588 billion in 2001. The decrease primarily reflects lower refining volumes, lower product prices and the impact of the sale of the retail natural gas marketing business in 2002.

Purchases of crude oil and products decreased to $1.298 billion in 2002 from $1.595 billion in 2001. The decrease was primarily due to reductions in EM&R's purchase requirements where improved refinery reliability, lower downstream sales levels and the sale of its retail natural gas marketing business, reduced the need for third party product purchases.

Operating, selling and general expenses were $1.292 billion in 2002, compared to $1.012 billion in 2001. The increase primarily relates to the higher expense of operating the expanded facilities at Oil Sands, including additional expenses related to unplanned maintenance shutdowns, employee benefits and insurance costs. These factors were partially offset by decreases in long-term incentive compensation costs (see note 11b), research and development costs and the absence of costs in 2002 related to the Stuart Oil Shale Project.

The continued weak performance of equity markets increased Suncor's employee future benefits cost to $52 million in 2002 from $30 million in 2001. Benefit costs are expected to increase to about $60 million in 2003. Annual costs beyond 2003 may change depending on market performance and/or changes in assumptions (see note 7).

In 2002 insurance expenses were $22 million reflecting an increase of $14 million due to higher premiums as a result of tightening insurance market capacity. In 2003, the company anticipates a further $5 million increase reflecting continued tight capacity.

To mitigate its exposure to property and business interruption losses, the company has purchased insurance policies with a combined coverage up to US$1.150 billion, net of deductible amounts. The policies stipulate a property loss deductible of US$10 million per incident and a business interruption loss deductible per incident based on the greater of US$50 million or 30 days of gross earnings lost (as defined in the respective insurance policies). Gross earnings can be influenced by such factors as production levels and commodity prices.

Depreciation, depletion and amortization increased to $585 million in 2002, compared to $360 million in 2001. Depreciation on Project Millennium assets that came into service in January 2002 accounted for approximately half of the increase. Overburden amortization was also up in 2002 reflecting increased production levels, higher removal costs and, to a lesser extent, a higher composite life-of-mine overburden stripping ratio of 0.47 compared to 0.43 in 2001.

Exploration costs in 2002 increased to $26 million, compared to $22 million in 2001. The increase primarily relates to lease retention costs incurred with respect to the **Firebag In-situ Oil Sands Project**.

Firebag In-situ Oil Sands Project
Firebag is designed to recover bitumen from deep oil sands deposits using horizontal drilling technology with minimal surface disturbance.

Royalty expenses decreased to $98 million in 2002, from $134 million in 2001, primarily due to lower natural gas prices. This decrease was partly offset by higher Oil Sands royalties due to higher production. The Oil Sands Crown royalty rate in 2002 was unchanged from 2001 at 1% of gross revenue.

Financing expenses (after capitalization of interest on projects) increased to $124 million in 2002, from $16 million in 2001. In 2001 interest of $103 million was capitalized on Project Millennium. Overall, financing costs (before capitalization of interest on projects) increased in 2002 to $155 million from $143 million in 2001, reflecting higher average debt levels in 2002.

Income tax expense increased to $383 million in 2002 from $125 million in 2001. Suncor's effective income tax rate in 2002 was 33%. This reflected a higher than anticipated 10% net reduction related to the federal resource allowance deduction and non-deductible Crown royalties (see note 8). Suncor's 2001 effective income tax rate was 24%, primarily reflecting a future income tax reduction of 6% related to federal resource allowance and non-deductible Crown royalties, as well as the effect of an 11% reduction in federal and provincial income tax rates on the revaluation of future income taxes.

Suncor anticipates its effective tax rate in 2003 will be about 35%. The effective rate can vary depending on changes in such factors as enacted tax rates, the resource allowance deduction and non-deductible Crown royalties. Based on prior years' investment levels and planned future

investment plans, Suncor does not expect its upstream operations to be cash taxable until 2010. This expectation can change depending on such factors as commodity prices, profitability, capital investments and changes in tax rates and laws.

Dividends
During 2002, Suncor's annual common share dividend, after accounting for the two-for-one stock split in May 2002, was $0.17 per share, unchanged from 2001. Dividend levels are reviewed quarterly in light of Suncor's growth-related initiatives, financial position, financing requirements, cash flow and other factors considered relevant by the Board of Directors.

Corporate Office Expenses
Corporate office after-tax expenses increased to $128 million in 2002 from $92 million in 2001. The increase reflects the higher financing costs discussed above, partially offset by lower long-term compensation costs and lower research and development expenditures.

The corporate office had a net cash deficiency of $225 million in 2002, compared to $165 million in 2001. The increase is a result of the payments associated with the long-term compensation plan and higher capital expenditures, partially offset by lower net income tax payments.

Trading Activities
In 2002, Suncor's Board of Directors approved commencement of energy trading activities and after developing an appropriate control framework, the company began limited trading activities in November. Trading activities are principally focused on the commodities the company produces, adding potential for new revenue and providing a new window into energy product markets. The company uses the mark-to-market method of accounting for the new energy trading activities. Under mark-to-market accounting, physical and financial energy contracts are recorded at fair value at each balance sheet date. The net gain or loss from the revaluation of these contracts is recorded in the Statement of Earnings for the period. Net trading losses were negligible for the period ended December 31, 2002.

A separate risk management function directs and monitors practices and policies and provides independent verification and valuation of Suncor's trading and marketing activities.

Critical Accounting Policies

Suncor's critical accounting policies are defined as those that are both important to the portrayal of the company's financial position and operations and require management to make judgments based on underlying estimates and assumptions about future events and their effects. Underlying estimates and assumptions are based on historical experience and other factors that are believed by management to be reasonable under the circumstances. These estimates and assumptions are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as Suncor's operating environment changes. The company believes the following are the most critical accounting policies and estimates used in the preparation of its consolidated financial statements. For information concerning the company's other significant accounting policies, see "Summary of Significant Accounting Policies" on page 41 of the Consolidated Financial Statements.

Property, Plant and Equipment
Suncor accounts for upstream exploration and production activities using the "successful efforts" method. The application of the successful efforts method of accounting requires Suncor's management to determine the proper classification of activities designated as developmental or exploratory, which ultimately determines the appropriate accounting treatment of the costs incurred. The results from a drilling program can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Where it is determined that exploratory drilling will not result in commercial production, the exploratory costs are written off and reported as "dry hole" costs (see note 18). Despite this, properties that are assumed to be productive may, over a period of time, actually deliver oil and gas in quantities insufficient to be economic. Tests of impairment of capitalized properties are based on estimates of future cash flow from the properties. Estimates of future cash flows are subject to significant management judgment concerning oil and gas prices, production quantities and operating costs. Where management assesses that a property is fully or partially impaired, the book value of the property is either completely removed from the company's records ("written off") or partially removed from the company's records ("written down").

The company's plant and equipment, including upgrading and refining assets, are amortized on a straight-line basis over the estimated useful life of the assets. The company determines useful life based on prior experience with similar assets and, as necessary, in consultation with others who have expertise with the assets in question. However, the actual useful life of the assets may differ from management's original estimate due to factors such as technological obsolescence, regulatory requirements and maintenance activity.

Employee Future Benefits
The company provides a range of benefits to its employees and retired employees, including pensions and other post-retirement health and dental care benefits as described in note 7. The determination of obligations under the company's benefit plans and related expenses requires the use of actuarial valuation methods and assumptions. Assumptions typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, return on plan assets, mortality rates and future medical costs. The fair value of plan assets is determined using market values. Actuarial valuations are subject to management judgment. As a result, the accrued benefit obligation and net periodic benefit cost for both pensions and other post-retirement benefits may differ significantly if different assumptions are used, as described in note 7.

Reclamation and Environmental Remediation Costs
Suncor's reclamation and environmental remediation costs represent the costs of reclaiming the environment or restoring a site to a useful and acceptable condition, as determined by statutory or regulatory authorities, by contractual agreement, or by Suncor management. The scope of the activities and the nature of the costs are normally outlined in the current reclamation or environmental remediation plan. These include costs specifically related to the reclamation or environmental remediation project and any other costs that can be clearly identified with the project.

Estimated reclamation costs at Oil Sands and NG are accrued on the unit of production basis based on proved and probable reserves. Estimated environmental remediation costs in EM&R are accrued in the period for those sites where assessments indicate that such work is required. Reclamation and environmental remediation costs are charged against earnings and reported as operating, selling and general expenses.

On an annual basis at Oil Sands and NG, the most probable costs of reclamation are estimated in current-year dollars, based on current information, the estimated timing of remedial actions, existing regulatory requirements and technology. If it is not possible to determine a most probable estimate, the lowest estimate in the range of equally probable estimates is used.

The greatest area of judgment and uncertainty with respect to the company's reclamation estimates relates to its Oil Sands mining leases where there is a requirement to provide for land productivity equivalent to predisturbed conditions. To reclaim tailings ponds, Suncor is using a process referred to as consolidated tailings. At this time no ponds have been fully reclaimed using this technology, although work is under way. The success and time to reclaim the tailings ponds could increase or decrease the current reclamation cost estimates. The company continues to monitor and assess other possible technologies and/or modifications to the consolidated tailings process now being used.

Suncor currently estimates remaining cash reclamation expenditures will be $610 million over the next 40 years. A 10% change in this estimate could impact Oil Sands annual reclamation provision by $3 million pretax.

Reserve Estimates

On an annual basis Suncor engages Gilbert Laustsen Jung Associates Ltd. (GLJ), independent petroleum consultants to either audit (Oil Sands mining leases) or conduct independent evaluations (Firebag in-situ and NG's conventional leases) of the company's reserve (1) estimates. The accuracy of any reserve estimate is a matter of interpretation and judgment and is a function of the quality and quantity of available data gathered over time.

Reserve Reconciliation(1)

	Oil Sands Mining Leases (millions of barrels of gross synthetic crude oil)			Firebag In-situ Leases (millions of barrels of gross synthetic crude oil)			Natural Gas Leases (billions of gross cubic feet)
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved
December 31, 2000	422	2 034	2 456	—	—	—	797
Additions	—	—	—	—	1 664(2)	1 664(2)	27
Revisions	(1)	(5)	(6)	—	—	—	(3)
Production	(45)	—	(45)	—	—	—	(65)
Dispositions	—	—	—	—	—	—	(1)
December 31, 2001	376	2 029	2 405	—	1 664	1 664	755
Additions	3	45	48	144	32	176	53
Revisions	54	(511)	(457)	—	—	—	(35)
Production	(75)	—	(75)	—	—	—	(65)
Dispositions	—	—	—	—	—	—	(2)
December 31, 2002	**358**	**1 563**	**1 921**	**144**	**1 696**	**1 840**	**706**

(1) In their audits or evaluations of Suncor's mining and in-situ leases, GLJ state they believe there is a 90% probability and 50% probability that proved and probable reserves estimates, respectively, will be exceeded. Accordingly, Suncor's probable oil sands reserves have not been further reduced for risk associated with obtaining production from such reserves. GLJ's mining and in-situ reserves estimates consider recovery from leases for which regulatory approvals have been granted, and are stated before the deduction of Crown and other royalties. Suncor reports its proved and probable reserves in accordance with Canadian disclosure requirements. The terms "proved" and "probable" reserves have the meanings ascribed to them in National Policy 2B of the Canadian Securities Administrators. U.S. companies are prohibited from disclosing estimates of probable reserves for non-mining properties in filings with the United States Securities and Exchange Commission. As a result, Suncor's reserve estimates may not be comparable to those made by U.S. companies.

(2) For Firebag reserves, the additions in 2001 and the year-end 2001 closing balance have been adjusted from a bitumen value of 2.029 billion barrels based on assumed coker (synthetic crude) yields of between 80% and 82%.

Oil Sands Mining Reserves

Proved and probable oil reserves estimates on Oil Sands mining leases are based on a detailed geological assessment, including drilling density and laboratory tests. Estimates also consider current production capacity and upgrading yields, current mine plans, operating life and regulatory constraints.

Subsequent to year-end 2002, management completed its reserve review and received the report of the independent consultants. As a result of this review, there was a revision to Suncor's probable Oil Sands mining reserves. Approximately half of this probable reserve revision reflects management's decision not to mine in less economic areas, as permitted by regulatory changes. The company could decide to mine these leases in the future. The balance of the revision incorporates additional knowledge and understanding of the Millennium mine.

Management will reflect the impact of the negative reserve revision in Oil Sands results beginning in 2003.

Firebag In-situ Reserves

For the Firebag Project, reserve estimates increased in 2002 primarily through the recognition of 144 million barrels of proved non-producing reserves. This increase reflects reclassification of a portion of probable reserves to proved status, now that the first stage of construction of the project is nearly complete and other similar industry projects have demonstrated commercial success of the in-situ process.

Natural Gas Reserves

Suncor's NG proved reserves declined in 2002 as a result of production in the year and revisions due to operating experience. These factors were only partially offset by drilling additions.

Overburden
As part of the process of mining oil sands, it is necessary to remove surface material such as muskeg, glacial deposits and sand. Overburden removal may precede mining of the oil sands deposit by as much as two years. Accordingly, the quantity of overburden removed in a given period may not bear any relationship to the quantity of oil sands actually mined in the period.

In order to ensure a proper matching of costs with revenues (such that each tonne of oil sands mined is allocated a proportionate share of overburden removal costs), the company has adopted the deferral method of accounting for overburden removal costs, whereby all such costs are initially set up as a deferred charge (see note 3).

To allocate the deferred overburden charges, a life-of-mine approach has been adopted for each mine pit, relating the removal of all overburden to the mining of all of the oil sands ore on leases where there is regulatory approval. By adopting this approach, an overburden stripping ratio is calculated that allows for the matching of revenues and expenses such that overburden removal costs are averaged over the life of the mine. Over time, through a combination of increased mine areas (as with the Millennium mine expansion), additional drilling activity and operational experience, the company has seen its stripping ratios vary, which can increase or decrease the overburden amortization costs charged to the earnings statement (see Oil Sands Overview on page 27).

Outlook

Production Growth at Oil Sands
Suncor is targeting an increase in production capacity to 260,000 bpd in 2005. Work is also under way to finalize plans for the Voyageur growth strategy, which has a goal of increasing production to 500,000 bpd to 550,000 bpd by 2010 to 2012. (For further details, see Oil Sands Overview on page 27).

Integration
The company continues to assess downstream integration opportunities to capture greater long-term value from its oil sands production. Natural gas production and the use of the natural gas in Suncor's operations is also a component of the corporate integration strategy (see Natural Gas Overview on page 32 and Energy Marketing and Refining Overview on page 35).

Capital Spending
In 2003, Suncor plans capital spending of more than $1 billion, with $496 million directed towards Oil Sands growth projects. This includes spending to support stage one of the Firebag Project as well as construction of a new vacuum unit for the Oil Sands upgrading facilities. Another $215 million will be spent to maintain Oil Sands operations, which includes completing a maintenance shutdown. In the downstream, the company plans to spend $145 million in 2003. The bulk of this spending will be allocated towards projects at Suncor's Sarnia refinery to meet pending gasoline and distillate desulphurization initiatives and integrate production streams from Oil Sands. Spending will also be directed to the Sunoco retail network to help maintain its competitive position in the Ontario market. The balance of Suncor's capital budget for 2003 is allocated to support the company's goal of growing

natural gas production ($160 million), and fund technology upgrades and renewable energy investments ($35 million).

Climate Change
Suncor's effort to reduce greenhouse gas emissions is reflected in its pursuit of greater internal energy efficiency, investment in emissions offsets and carbon capture research and development.

Suncor continues to consult with governments about the impact of the Kyoto Protocol and plans to continue to actively manage its greenhouse gas emissions. Suncor currently estimates that in 2010 the impact of the **Kyoto Protocol** on Oil Sands cash operating costs would be about $0.20 to $0.27 per barrel. This estimate assumes a reduction obligation of 15% from 2010 **business-as-usual energy intensity** and that the maximum price for carbon credits would, as the Government of Canada indicated in late 2002, be capped at $15 per tonne of carbon dioxide equivalent. Based on these assumptions, Suncor does not currently anticipate the cost implications of the Kyoto Protocol will have a material impact on its business or future growth plans. The ultimate impact of Canada's anticipated implementation of the Kyoto Protocol, however, remains subject to numerous risks, uncertainties and unknowns. These include the outcome of discussions between the federal and provincial governments, the form, impact and effectiveness of implementing legislation, the ultimate allocation of reduction obligations among economic sectors, and other details of Canada's implementation plan, as well as international developments. In addition, the Government of Canada has not yet indicated what, if any, limitations will be placed on the price of carbon credits after 2012. It is not possible to predict how these and other Kyoto related issues will ultimately be resolved.

Kyoto Protocol

An international agreement to reduce emissions of greenhouse gases. Canada ratified the Kyoto Protocol in December 2002.

business-as-usual energy intensity

Reflects the level of greenhouse gas emissions that would have occurred in the absence of energy efficiency and process improvements after 1990.

Renewable Energy
As the company expands its hydrocarbon-based businesses, Suncor expects to continue to work toward the development of renewable energy, which has the potential to reduce environmental impacts and create additional business investment opportunities.

This strategy was reflected in the company's announcement to invest $100 million between 2000 and 2005 on renewable energy projects.

In 2002, Suncor officially launched the SunBridge Wind Power Project, a partnership with Enbridge Inc. In 2003, Suncor's goal is to launch investment plans for additional wind power projects.

Risk/Success Factors Affecting Performance

Suncor believes that while its business strategies will provide strategic advantages, they also present issues that will require prudent risk

management. The issues Suncor must manage include, but are not limited to, commodity prices, environmental regulations, stakeholder support for growth plans, regional labour issues and the further specific issues discussed under Risk/Success Factors Affecting Performance for each Suncor business as well as the more detailed risk factors described in Suncor's most recent Annual Information Form/Form 40-F, filed with securities regulatory authorities.

Commodity Prices

Suncor's future financial performance remains closely linked to hydrocarbon commodity prices, which can be influenced by many factors including global and regional supply and demand, worldwide political events and the weather. These factors, among others, can result in a high degree of price volatility. For example, from 2000 to 2002 the monthly average price for benchmark WTI crude oil ranged from a low of US$19 per barrel to a high of US$34 per barrel. During the same period, the natural gas Henry Hub benchmark monthly average price ranged from a low of US$1.89 per mcf to a high of US$9.79 per mcf.

Crude oil and natural gas prices are based on a U.S. dollar benchmark that results in Suncor's realized prices being influenced by the Canadian/U.S. currency exchange rate, creating an element of uncertainty for the company. However, the impact of foreign exchange fluctuations on earnings is partially mitigated by the company's U.S. dollar denominated long-term debt and preferred securities. The company estimates that a

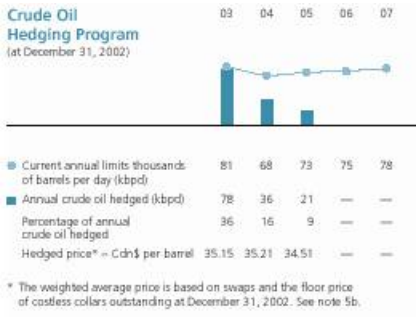
$0.01 change in the Cdn$:US$ exchange rate would have a $10 million after-tax impact on net earnings with respect to U.S. dollar denominated long-term debt and a $3 million after-tax impact on net earnings attributable to common shareholders related to U.S. dollar denominated preferred securities.

During 2002, the fluctuation of the Canadian dollar against the U.S. dollar resulted in a net $8 million after-tax unrealized foreign exchange gain on the company's U.S. dollar denominated long-term debt and a $1 million after-tax unrealized foreign exchange gain with respect to Suncor's U.S. dollar denominated preferred securities.

Hedging

Suncor cannot control or accurately predict the prices of crude oil or natural gas, or currency exchange rates. For this reason, the company has a hedging program that fixes a price or range of prices for crude oil for a percentage of Suncor's total production (see note 5). Suncor's risk management objective with its hedging program is to reduce its exposure to market volatility and support the company's ability to finance growth.

The Audit Committee and the Board of Directors meet with management regularly to assess Suncor's hedging thresholds in light of its price forecast and cash requirements. To add more certainty to Suncor's ability to finance future capital programs and repay debt, the Board authorized hedging approximately 35% of the company's crude oil volumes in 2003 and up to 30% for the period 2004 to 2006. In 2002, hedging decreased Suncor's earnings by $160 million. In 2001, hedging decreased earnings by $148 million.



	03	04	05	06	07
Current annual limits thousands of barrels per day (kbpd)	81	68	73	75	78
Annual crude oil hedged (kbpd)	78	36	21	—	—
Percentage of annual crude oil hedged	36	16	9	—	—
Hedged price* – Cdn$ per barrel	35.15	35.21	34.51	—	—

* The weighted average price is based on swaps and the floor price of costless collars outstanding at December 31, 2002. See note 5b.

Environmental Regulation

Environmental legislation affects nearly all aspects of Suncor's operations, imposing certain standards and controls on activities relating to oil and gas mining and conventional exploration, development and production. Environmental legislation also affects refining, distribution and marketing of petroleum products and petrochemicals and requires companies engaged in those activities to obtain necessary permits to operate. Environmental assessments and approvals are required before initiating most new projects or undertaking significant changes to existing operations.

In addition to these specifically known requirements, Suncor expects changes to environmental legislation could impose further requirements on companies operating in the energy industry. Some of the issues include the possible cumulative impacts of oil sands development in the Athabasca region; the need to reduce or stabilize various emissions; issues relating to global climate change, including the uncertainties and risks associated with Canada's implementation of the Kyoto Protocol and uncertainties associated with predicting emission intensity levels from Suncor's future production; and other potential impacts of government regulation in areas such as land reclamation and restoration, water quality and reformulated fuels to support lower vehicle emissions. Changes in environmental regulation could have an adverse effect on Suncor in terms of product demand, product formulation and quality, methods of production and distribution and operating costs. The complexity of these issues makes it difficult to predict their future impact on the company. Management anticipates capital expenditures and operating expenses could increase in the future as a result of the implementation of new and increasingly stringent environmental regulations.

Other Factors

Other critical factors affecting Suncor's financial results include volumes and margins of refined product sales, success of the natural gas exploration and development program including coal bed methane initiatives, interest rates and the company's ability to manage both day-to-day operating costs as well as reclamation and remediation costs and project costs on existing and future projects.

Sensitivity Analysis

	2002 Average	Change	Approximate Change in Pretax Cash Flow from Operations	Approximate Change in After-tax Earnings
Oil Sands				
Price of crude oil ($/barrel)	Cdn$ 33.65	US$ 1.00	81	54
Sweet/sour differential ($/barrel)	Cdn$ 7.86	US$ 1.00	28	19
Sales (barrels/day)	205 300	1,000	11	7
Natural Gas				
Price of natural gas ($/mcf)	Cdn$ 3.91	0.10	5	2
Production of natural gas (mmcf/d)	179	10	11	4
Energy Marketing and Refining				
Retail gasoline margins (cents/litre)	6.6	0.1	2	1
Refining/wholesale margin (cents/litre)	4.8	0.1	5	3
Consolidated				
Exchange rate: Cdn$:US$	0.64	0.01	34	32
Interest rate — on variable rate borrowings	3.1%(1)	1%	14	9

(1) Borrowing with interest at weighted average variable rates of 3.1% at December 31.

The sensitivity analysis shows the main factors affecting Suncor's annual pretax cash flow from operations and after-tax earnings (in Cdn$ millions) based on actual 2002 operations. The table illustrates the potential financial impact of these factors applied to Suncor's 2002 results. A change in any one factor could compound or offset other factors.

Liquidity and Capital Resources

Net debt decreased to $2.671 billion at the end of 2002, a reduction of $462 million, excluding the $10 million effect of an unrealized foreign currency translation gain. As at December 31, 2002, the company had fixed-term debt (before the effect of interest rate swap transactions) of approximately $1.8 billion, with the balance comprised of variable rate borrowings and fixed-term capital leases.

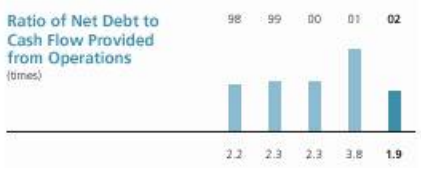
Suncor has sufficient lines of credit to meet working capital requirements and will continue to monitor capital markets for opportunities to refinance bank debt with long-term debt. Suncor's undrawn lines of credit at December 31, 2002 were approximately $1.1 billion.

In the first quarter of 2002, Suncor issued US$500million of 7.15% unsecured notes due 2032 from a US$1 billion unallocated shelf prospectus. The net proceeds from the sale were used to repay commercial paper and bank borrowings. Also in the first quarter of 2002, Suncor filed a shelf prospectus with Canadian securities regulatory authorities, enabling it to issue up to a further $500 million in medium-term notes in Canada if required. No notes were issued under the Canadian shelf prospectus during the year.

Interest expense continues to be influenced by the composition of the company's debt portfolio (in particular its variable rate borrowings) with short-term floating interest rates at historic lows. To manage its fixed versus floating rate exposure, Suncor has entered into a number of interest rate swaps with investment grade counterparties, resulting in the swapping of $490 million of net fixed rate debt to variable rate borrowings.

Suncor's capital resources at December 31, 2002, consist primarily of cash flow provided from operations, available lines of credit and the remaining debt and equity capacity under the shelf prospectuses. Suncor's level of earnings and cash flow provided from operations depends on many factors, including commodity prices, production levels and downstream margins. Suncor believes it will be able to fund its 2003 capital spending program of approximately $1 billion from the above-noted capital resources.

Debt reduction is a priority for Suncor as it prepares for the next stages of growth. Management believes a phased approach to future growth projects should improve its ability to manage project costs and provide further opportunities for debt reduction. This approach, along with anticipated higher Oil Sands sales levels and the hedging of approximately 35% of crude oil



production in 2003, should allow Suncor to continue reducing both the absolute debt level and the ratio of net debt to cash flow provided from operations. Suncor's long-term target for this ratio is 2.0 times at mid-cycle commodity pricing. At the end of 2002 this ratio was 1.9 times compared to 3.8 times as at December 31, 2001. The decrease is due to a combination of increased cash flow from operations, lower year-end net debt and lower project spending with the completion of Project Millennium.

Aggregate Contractual Obligations and Off-balance Sheet Financing

	Payments Due by Period				
($ millions)	**Total**	**2003**	**2004 — 2005**	**2006 — 2007**	**Later years**
Commercial paper	548	—	—	548	—
Bank debt	199	—	199	—	—
Fixed-term debt and capital leases	1 939	12	223	406	1 298
Operating lease agreements and pipeline capacity and energy services commitments	5 207	216	413	409	4 169

Total	**7 893**	**228**	**835**	**1 363**	**5 467**

At December 31, 2002 Suncor had three off-balance sheet arrangements with Special Purpose Entities (SPE) as described in note 9c. In 2002, the company had in place a securitization program to sell, on a revolving, fully serviced and limited recourse basis, up to $170 million of accounts receivable having a maturity of 45 days or less to a third party SPE. In 1999, the company sold 2,130,000 barrels of its crude oil inventory for $49 million to a SPE while retaining use of the inventory for its operations through a five-year agreement. Also in 1999, the company entered into an equipment sale and leaseback arrangement with a SPE for proceeds of $30 million.

The company is currently in the process of assessing the impact of recently issued U.S. accounting interpretations and will assess new Canadian accounting interpretations when issued. These new standards may require consolidation of one or more of the above-noted off-balance sheet arrangements.

Planning Assumptions

	2002 Actual Average for the year	Current Plan Average next 3-year range	2001 Plan Average next 3-year range
Crude oil — WTI US$ per barrel	**26.10**	20.00 - 22.00	19.00 - 21.00
Natural gas — US$/thousand cubic feet @ Henry Hub	**3.25**	3.40 - 3.60	3.00 - 3.45
Exchange rate: Cdn$:US$	**0.64**	0.65	0.65 - 0.69

The above are planning assumptions and are not estimates or predictions of actual future events or circumstances. This table does not incorporate potential cross-relationships, and does not necessarily accurately predict future results.

Recently Issued Accounting Standards

For a discussion of recently issued Canadian accounting standards relating to “Hedging Relationships” and “Asset Retirement Obligations,” see “Summary of Significant Accounting Policies” on page 41.

Oil Sands Overview

Suncor’s Oil Sands business, located near Fort McMurray, Alberta, continues to be the primary focus of the company’s development plans throughout the next decade. The business mines oil sands ore, extracting and upgrading the bitumen into refinery feedstock and diesel fuel.

Oil Sands strategy is based on:

- Increasing oil production by applying proven technologies to develop Suncor’s **oil sands** resources.

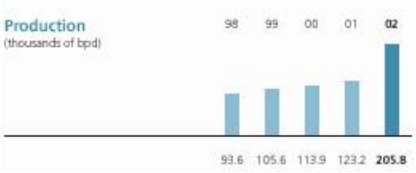
  oil sands
  Oil sands are naturally occurring mixtures of bitumen, water, sand and clay.

- Reducing costs through application of technologies, economies of scale, direct management of growth projects, strategic alliances with key suppliers and continuous improvement of operations.
- Building strategic business relationships to mitigate downstream risk and capture value from the production and marketing of synthetic crude oil and by-products.

Summary of Results
Year ended December 31

($ millions unless otherwise noted)	2002	2001	2000
Revenue	**2 659**	1 385	1 336
Production (thousands of bpd)	**205.8**	123.2	113.9
Average sales price ($/barrel)	**33.65**	29.17	31.67
Net earnings	**793**	283	315
Cash flow provided from operations	**1 480**	486	655
Total assets	**6 896**	6 409	5 079
Investing activities	**630**	1 476	1 715
ROCE (%)(1)	**16.8**	20.1	22.8
ROCE (%)(2)	**15.6**	6.4	10.6

(1) Excluding capitalized costs related to major projects in progress.
(2) Includes capitalized costs related to major projects in progress.



Analysis of Net Earnings

Oil Sands net earnings were $793 million in 2002, compared with $283 million in 2001. Increased earnings were primarily the result of higher

sales revenues from both increased production and the strengthening of benchmark crude prices over the course of the year. Net earnings also benefited from an improved sales mix of higher value sweet crude oil and diesel fuel relative to lower value sour crude oil and bitumen, lower product differentials and the absence of Project Millennium start-up costs. Partially offsetting these factors were higher cash and non-cash expenses, higher hedging losses, and a higher effective tax rate in 2002 compared to 2001. The 2001 effective tax rate was lower due to the positive earnings impact of enacted provincial rate reductions in 2001 applied to Oil Sands future income tax liabilities.

During 2002, Oil Sands production increased to an average of 205,800 barrels per day (bpd), compared to 123,200 bpd in 2001. The higher production resulted in

increased average sales of 205,300 bpd, compared to 121,500 bpd in 2001. The impact of higher sales levels increased year-over-year net earnings by $593 million.

The increase in production and sales was primarily the result of Suncor's Project Millennium expansion, which was commissioned in December 2001. Project Millennium increased Oil Sands production capacity to 225,000 bpd. However, challenges in bringing the new Millennium facilities to capacity during the first half of 2002 impacted production and sales levels for the year. Oil Sands production steadily climbed to 227,600 bpd in the fourth quarter from the first quarter average of 179,300 bpd. By the end of 2002, the Millennium assets were performing well with what management believes were relatively few technical issues for a plant of its scale and complexity.

Net earnings were also favourably impacted by an increase in Oil Sands crude oil price realization that averaged $33.65 per barrel (including pretax hedging losses) in 2002 compared to $29.17 per barrel (including pretax hedging losses) in 2001.

The increase in average price realization was due to three factors:

- A strengthening of the 2002 WTI benchmark price throughout the year, which corresponded with increasing production. On an overall basis, the WTI benchmark price averaged US$26.10 per barrel in 2002, compared to US$25.90 per barrel in 2001.
- Improved sweet crude oil and diesel product mix, which increased to 62% of total Oil Sands production from 58% in 2001.
- Narrowing of sour crude oil and bitumen price differentials partially offset by the narrowing of the diesel premium.

The impact of these favourable factors increased Oil Sands 2002 net earnings by $204 million.

Royalties

Crown royalties in effect for Oil Sands mining operations require payments to the Government of Alberta of 25% of net revenues less allowable costs (including the deduction of capital expenditures), subject to a minimum payment of 1% of gross revenues before hedging activity. In both 2002 and 2001, Oil Sands was subject to the minimum 1% rate. However, as a result of increased sales levels, Crown royalties increased to $28 million in 2002 from $15 million in 2001.

Based on current assumptions in Suncor's annual planning cycle relating to future oil prices, production levels, operating costs and capital expenditures, the company expects to continue to pay the minimum 1% rate until 2010.

The Firebag in-situ leases, which are not yet in production, will be under the same royalty regime as Suncor's mining leases.

In addition to Crown royalties, Suncor paid royalties to Anadarko Petroleum Corporation (Anadarko) for mining a lease on which Anadarko had a royalty interest. Royalties paid to Anadarko were $5 million in 2002, compared to $15 million in 2001. Mining on the lease was substantially completed in 2002 and Suncor does not anticipate paying significant royalties to Anadarko in future years. In 2002, Suncor commenced mining on a lease subject to a royalty in favour of Petro-Canada, calculated at 1.5% of the net sale proceeds from the lease. No royalties were payable to Petro-Canada in 2002.

The increase in Crown and other royalties year-over-year reduced Oil Sands after-tax income by $2 million.

Expenses

Cash operating costs (excluding project start-up costs) increased to $829 million compared to $493 million in 2001, reducing Oil Sands after-tax earnings by approximately $205 million. The increase was primarily due to higher structural operating costs associated with the increase in production capacity, including higher natural gas consumption, maintenance and increased labour costs. Oil Sands also incurred additional costs related to a two-day power outage in the first quarter, work performed on the new Millennium facilities during the first half of the year and an unplanned maintenance shutdown in the third quarter of 2002.

Project start-up costs were $3 million in 2002, compared to $141 million in 2001. The decrease reflects reduced costs resulting from the completion of Project Millennium. The decrease resulted in an after-tax earnings improvement of $88 million.

During 2002, Oil Sands incurred exploration costs of $9 million related to retention activities on its Firebag leases, reducing Oil Sands after-tax earnings by $6 million. There were no such costs in 2001. During 2003, Oil Sands anticipates a similar level of costs pertaining to its Firebag leases.

Non-cash charges (depreciation, depletion and amortization) increased to $450 million in 2002 from $233 million in 2001. The increase was

primarily due to additional depreciation related to the Project Millennium assets and $99 million in higher overburden amortization costs. These factors decreased after-tax earnings by $141 million.

The higher overburden amortization in 2002 primarily reflects increased production levels, higher removal costs and, to a lesser extent, a higher composite life-of-mine overburden stripping ratio.

In 2002, Oil Sands composite stripping ratio was 0.47 cubic metres of overburden for every tonne of ore mined. In 2001 this ratio was 0.43 cubic metres per tonne.

The higher composite stripping ratio in 2002 was a result of a higher proportion of production from Millennium, which had a higher stripping ratio (0.58) than Steepbank (0.36). In 2003, the Millennium mine pit ratio will change to 0.56. Over time, with a greater proportion of total mining production expected to come from Millennium, and assuming no other changes, the composite stripping ratio will approach the estimated Millennium life-of-mine ratio of 0.56. This will increase the overburden amortization cost.

Partially offsetting expected higher overburden amortization costs is an expected improvement in bitumen recovery. The company estimates that on a life-of-mine basis, the bitumen recovery per tonne of ore in the Millennium mine pit will be approximately 0.69 barrels, compared to 0.61 in Steepbank.



Selling price – The average price from the sale of crude oil, including the impact of hedging activities.

Cash margin – The difference between the selling price received for products sold and cash operating cost per barrel (excluding start-up costs) plus royalties per barrel.



Cash operating costs were higher than the company's original goal of $10.00 to $10.50 per barrel and increased over 2001. The increase is primarily attributed to higher costs and lower than anticipated sales.

Due to the use of judgment and the extended time frame associated with the company's stripping ratio and bitumen recovery estimates, actual results may differ and these differences may be material.

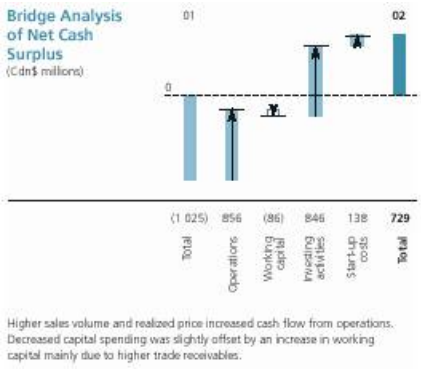
Net Cash Surplus Analysis

Cash flow provided from operations was $1.48 billion in 2002, compared with $486 million in 2001. The increase was primarily due to the factors that increased net income as described above, partially offset by an increase in overburden expenditures.

Oil Sands working capital increased by $121 million in 2002, compared to an increase of $35 million in 2001. This $86 million year-over-year increase in working capital is primarily due to higher trade receivables as a result of both higher sales levels and a higher WTI benchmark at year-end 2002, partially offset by increased accrued hedging losses.

Investing activities decreased to $630 million in 2002 from $1.476 billion in 2001. The decrease was primarily due to lower capital expenditure requirements in 2002 with the completion of Project Millennium in 2001, partially offset by increased capital spending on the Firebag Project and related upgrader improvements of $408 million.

These combined factors resulted in a net cash surplus of $729 million in 2002, compared to a net cash deficiency of $1.025 billion in 2001.



Higher sales volume and realized price increased cash flow from operations. Decreased capital spending was slightly offset by an increase in working capital mainly due to higher trade receivables.

Outlook

The foundation of Suncor's growth plans is the resource base estimated to be in place on the company's oil sands leases. Independent estimates currently place total Oil Sands mining and in-situ recoverable bitumen **resources** at nearly 13 billion barrels including proved and unrisked probable in-situ and mining bitumen reserves estimated at approximately 4.7 billion barrels.

resources
Resources include proved and probable reserves (see page 21). Resources also include quantities of oil and gas that are estimated, on a given date, to be potentially recoverable from known accumulations and undiscovered accumulations, that are not proved or probable reserves. Resources are a higher risk and are generally believed to be less likely to be recovered than proved and probable reserves. Total resources include synthetic crude oil estimates for both mining leases and for in-situ oil sands leases. Information on probable reserves and resources included in Management's Discussion and Analysis are reported in accordance with Canadian disclosure requirements. U.S. companies are prohibited in filings with the United States Securities and Exchange Commission from disclosing estimates of probable reserves and resources for non-mining properties. As a result, Suncor's reserve estimates may not be comparable to those made by U.S. companies.

Suncor's future plans for Oil Sands remain focused on activities expected to increase production, decrease operating costs and improve environment, health and safety performance.

Production Plans
In 2003, production at Oil Sands is expected to average about 215,000 bpd. Production will be lower than the plant's 225,000 bpd capacity as a result of a 30-day maintenance shutdown, currently scheduled for the second quarter of 2003. The maintenance work will result in the shutdown of Upgrader #1. Production at Oil Sands is expected to average 110,000 bpd during the maintenance period. Costs for the maintenance shutdown are budgeted at $65 million to $70 million. These costs will be amortized over the period to the next planned shutdown, tentatively scheduled for 2005 or 2006.

During the maintenance shutdown, Suncor plans to tie a new fractionator into the upgrader complex, replacing the existing unit, which has been in operation since 1967.

Operating Costs
Reducing operating costs is a strategic priority for Oil Sands. The business's goal for 2003 is to reduce its average cash operating cost to $12.50 per barrel (excluding project start-up costs). This goal assumes a production rate average of 215,000 bpd, reflecting both the production and cost impact of the 30-day maintenance shutdown.

The company expects production rates will improve following the maintenance shutdown. The higher production, combined with cost-saving initiatives Oil Sands expects to implement, have resulted in a target of reducing cash operating costs during the fourth quarter of 2003 to as low as $10 to $11 per barrel (excluding project start-up costs).

Suncor's cash operating cost goals assume the price of natural gas will average about US$3.60 per thousand cubic feet during 2003. Continued high natural gas prices will pose a significant challenge to reaching year-end cost reduction goals. A change of US$1 per thousand cubic feet in the Henry Hub price of natural gas would result in a change of approximately Cdn$0.50 per barrel to cash operating costs. However, because Suncor is a net producer of natural gas, continued high prices will have a positive impact on earnings.

Beyond 2003, Oil Sands will continue to pursue cost reductions while also developing and integrating new technologies and processes that have the potential to further improve competitiveness.

Firebag In-situ Oil Sands Project
The first stage of the Firebag In-situ Oil Sands Project is expected to begin commercial bitumen production in 2004. Full production from the first stage, targeted at 35,000 barrels per day of bitumen, is not expected until mid-2005. Combined with associated investments in the upgrader, the Firebag Project is expected to contribute to a planned increase in Oil Sands production capacity to 260,000 bpd in 2005, at a total cost of approximately $1 billion. The project remains on schedule and on budget. Engineering is under way on the second stage of Firebag.

Voyageur

In late 2001, Suncor issued a public disclosure document for the Voyageur growth strategy, which targets increasing production to 500,000 to 550,000 bpd in 2010 to 2012. When Suncor originally announced plans, the company stated it would apply for regulatory approval in late 2002.

Following initial stakeholder consultation and preliminary engineering, Suncor modified its Voyageur plan, deferring applications for regulatory approval until further details about each project phase are known and can be more fully discussed with stakeholders. Although the timing of Suncor's regulatory approval strategy has changed, the company's goal of increasing production capacity to 500,000 to 550,000 bpd in 2010 to 2012 remains the same.

Cost estimates for the Voyageur growth strategy will be provided once preliminary engineering is completed for each phase. Ultimate development of the Voyageur growth project requires approval of regulators and Suncor's Board of Directors.

Risk/Success Factors Affecting Performance

Management believes the strategic advantages of Oil Sands growth include:

- Economies of scale associated with higher levels of production from the existing Oil Sands infrastructure.
- Parallel processing in the extraction and upgrading processes that provides flexibility to schedule periodic plant maintenance while continuing to generate production from the remaining units.
- Access to nearly 13 billion barrels of bitumen resources with the potential to generate production growth without the level of exploration risk associated with conventional oil and gas operations.

Certain issues Suncor must manage that may affect performance include, but are not limited to the following:

- Suncor's ability to finance Oil Sands growth in a volatile commodity pricing environment. Also refer to Corporate Overview, Liquidity and Capital Resources on page 25.
- The ability to complete future Oil Sands growth projects both on time and on budget. This could be impacted by competition from other projects (including other oil sands projects) for skilled people, increased demands on the Fort McMurray, Alberta infrastructure (housing, roads, schools, etc.), or higher prices for the products and services required to operate and maintain the Oil Sands plant. Suncor continues to address these issues through a comprehensive recruitment and retention strategy, working with the community to determine infrastructure needs, designing Oil Sands expansion to reduce unit costs, seeking strategic alliances with service providers and developing internal core competency in engineering, procurement and project management.
- Potential changes in the demand for refinery feedstock and diesel fuel. Suncor believes it can reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding its customer base and offering customized blends of refinery feedstock to meet customer specifications.
- Volatility in crude oil and natural gas prices and exchange factors and the light/heavy and sweet/sour crude oil differentials. Prices and differentials are difficult to predict and impossible to control.
- Unplanned production or operational outages and slowdowns. Outages can impact both production levels and costs.
- Suncor's relationship with its trade unions. Work disruptions have the potential to adversely affect Oil Sands operations and growth projects. Suncor's current collective agreement with the Communications, Energy and Paperworkers Union, Local 707 expires May 1, 2004.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 38 under "Forward-looking Statement." Also refer to Corporate Overview, Risk/Success Factors Affecting Performance on page 23.

Natural Gas Overview

Suncor's Natural Gas business (NG) produces conventional natural gas in Western Canada and is exploring potential opportunities for coal bed methane production in North America. NG's production provides a price hedge for the natural gas consumed internally within Suncor's oil sands operations and downstream refinery.

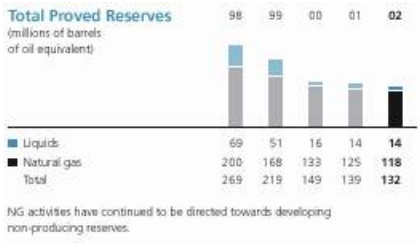
In 2002, NG continued to advance its four-point strategy for profitable growth:

- Focusing on natural gas production to keep pace with growing projected internal consumption to maintain a **price hedge**.

  price hedge
  Suncor-generated natural gas production that exceeds internal consumption provides the company a degree of protection from volatile market prices. In 2002, Suncor produced 179 million cubic feet per day (mmcf/d) of natural gas compared to consumption of approximately 110 mmcf/d.

- Building competitive operating areas.
- Improving base business efficiency.
- Creating new, low-capital business opportunities.

NG's 2002 average natural gas and liquids production volume of 33,700 barrels of oil equivalent per day (boe/d) was comparable to the 2001 average of 33,400 boe/d. Volume additions from new production in NG's core Western Canada operating areas were partially offset by natural reservoir declines in existing wells. Natural gas volumes as a percentage of total NG production remained constant at 88% in 2002 and 2001.

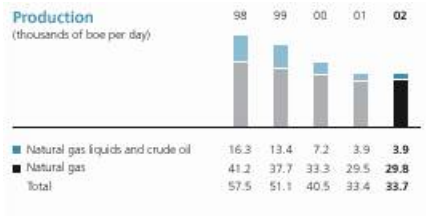


Summary of Results

Year ended December 31

($ millions unless otherwise noted)	2002	2001	2000
Revenue	**315**	458	428
Production (thousands boe/d)	**33.7**	33.4	40.5
Natural gas (mmcf/day)	**179**	177	200
Natural gas liquids (thousands bpd)	**2.4**	2.4	3.0
Crude oil (thousands bpd)	**1.5**	1.5	4.2
Average sales price			
Natural gas ($/thousand cubic feet)	**3.91**	6.09	4.72
Natural gas liquids ($/barrel)	**29.35**	34.38	36.66
Crude oil ($/barrel)	**31.72**	33.92	29.50
Net earnings	**35**	117	98
Cash flow provided from operations	**164**	280	238
Total assets	**765**	722	762
Investing activities	**158**	113	(186)
ROCE (%)	**9.2**	32.1	17.2

Natural gas converts to barrels of oil equivalent (boe) at a 6:1 ratio (six thousand cubic feet of natural gas:barrel of oil)

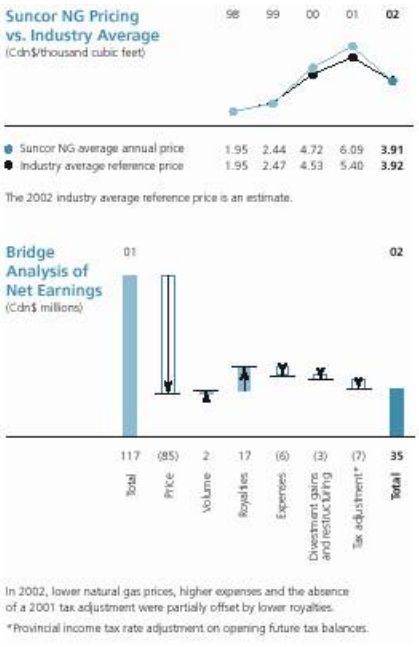


Analysis of Net Earnings

NG's net earnings decreased to $35 million in 2002, from $117 million in 2001. The decrease was primarily due to lower natural gas prices, increased expenses and a higher effective income tax rate in 2002 compared to 2001, partially offset by lower royalty expenses. The 2001 effective tax rate was lower due to the positive earnings impact of enacted provincial rate reductions in 2001 applied to NG's future income tax liabilities.

Pricing

In 2002, NG's average price realized for natural gas was $3.91 per thousand cubic feet (mcf), 36% lower than the average $6.09 per mcf realized in 2001. High industry inventory levels at the beginning of 2002 and weaker industrial demand due to economic recession in the United States contributed to lower prices during the year. Prices for crude oil, which accounts for about 5% of NG production, were marginally lower at $31.72 per barrel (including hedging losses), compared to $33.92 per barrel (including hedging losses) in 2001. Natural gas liquids, accounting for the remaining 7% of production, averaged $29.35 per barrel in 2002, compared to $34.38 per barrel in 2001. The combined impact of the above pricing factors decreased earnings by $85 million compared to 2001.



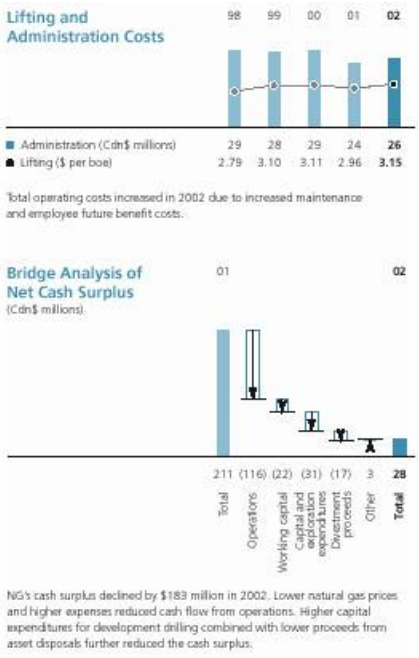
Total Expenses

Royalties on NG production decreased to $65 million ($5.27 per boe) in 2002, from $104 million ($8.56 per boe) in 2001, reflecting lower average commodity prices. Lower royalties had a positive impact on earnings of $17 million for 2002.

Total expenses, excluding royalties, restructuring costs and divestment gains, increased to $179 million in 2002 from $168 million in 2001. Natural gas purchases were $7 million higher reflecting increased purchases made by NG on behalf of Suncor's Sarnia refinery. Operating expenses increased to $69 million in 2002 from $64 million in 2001 due to increased maintenance and higher costs related to employee benefits. Non-cash depreciation, depletion and amortization expenses of $75 million in 2002 increased by $5 million as a result of higher depletion rates. Offsetting these items were exploration expenses, which decreased by $5 million in 2002 due to lower seismic expenditures as a result of reduced exploration activities. The combined impact of the above expense items decreased earnings by $6 million compared to 2001.

Net Cash Surplus Analysis

NG had a net cash surplus of $28 million in 2002, compared to a net cash surplus of $211 million in 2001. Cash flow provided from operations decreased to



$164 million in 2002, from $280 million in 2001 primarily as a result of lower prices and higher expenses, partially offset by lower royalty payments. Working capital decreased by $22 million in 2002, compared to a decrease of $44 million in 2001, due to a reduction in accounts receivable. Investing activities increased to $158 million in 2002, compared to $113 million in 2001. The $45 million increase reflects increased development drilling in existing focus areas, partially offset by lower divestment proceeds.

Outlook

NG's long-term goal is to achieve a sustainable return on capital employed of a minimum of 12% at mid-cycle natural gas prices (US$3.00 to US$3.50/mcf). To meet this target, management plans to increase production and continue work to improve base business efficiency, with a focus on reducing operating costs and capturing supply chain management benefits.

NG's long-term strategy is to increase production to exceed growing internal natural gas demands at the company's other integrated businesses. Internal demand in the latter half of 2003 is expected to grow to approximately 120 mmcf/d from 110 mmcf/d in 2002 in response to steam requirements for the Firebag In-situ Oil Sands Project. Internal demand is expected to continue to increase as subsequent stages of the Firebag Project begin production.

Suncor has budgeted $160 million in capital spending to support NG's 2003 production target of 185 to 190 mmcf/d of natural gas and approximately 3,300 barrels per day of liquids. The company plans to continue to leverage its expertise and existing assets to bring established reserves into production in western Alberta and northeastern British Columbia. However, increasing production will likely require expansion through industry arrangements such as **farm-ins**, joint ventures and acquisitions, which could expand the size and number of operating areas.



farm-ins
Acquisitions of all or part of the operating rights from the working interest owner. The acquirer assumes all or some of the burden of development in return for an interest in the property. The assignor usually retains an overriding royalty but may retain any type of interest.

Risk/Success Factors Affecting Performance

Certain issues Suncor must manage that may affect performance of the NG business include, but are not limited to, the following:

- Consistently and competitively finding and developing reserves that can be brought on stream economically. Positive or negative reserve revisions arising from technical and economic factors can have a corresponding positive or negative impact on asset valuation and depletion rates.
- The impact of market demand for land and services on capital and operating cost. Market demand and the availability of opportunities also influences the cost of acquisitions and the willingness of competitors to farm-out prospects.
- Risks and uncertainties associated with obtaining regulatory approval for exploration and development activities. These risks could add to costs or cause delays to projects.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 38 under "Forward-looking Statement." Also refer to the Corporate Overview, Risk/Success Factors Affecting Performance on page 23.



Energy Marketing and Refining Overview

Suncor's Energy Marketing and Refining (EM&R) business markets the company's refined products to industrial, wholesale and commercial customers principally in Ontario and Quebec, and to retail customers in Ontario through Sunoco-branded and joint venture operated retail networks. EM&R operates Suncor's refinery in Sarnia, Ontario, which has capacity to process 70,000 barrels per day of crude oil into gasolines, distillates and petrochemicals.

EM&R's downstream strategy is focused on:

- Enhancing the profitability of refining operations by improving reliability and product yields and enhancing operational flexibility to process a variety of feedstock.
- Increasing the profitability and efficiency of retail networks by improving average site throughput and growing non-fuel ancillary retail revenue.
- Creating downstream integration opportunities to capture greater long-term value from Oil Sands production.

EM&R's retail networks in Ontario provide marketing channels for the company's refined products, accounting for approximately 62% of EM&R's total 2002 sales volumes of 91,100 barrels per day (bpd). EM&R's retail networks include 287 Sunoco-branded retail service stations, 18 Sunoco-

branded Fleet Fuel Cardlock sites, and two 50% retail joint venture(1) businesses comprising 148 Pioneer retail service stations, 50 UPI retail service stations and 15 UPI bulk distribution facilities for rural and farm fuels.

(1) Pioneer Group Inc. is an independent company with which Suncor has a 50% joint venture partnership. UPI Inc. is a 50% joint venture company with GROWMARK Inc., a Midwest U.S. retail farm-supply and grain marketing co-operative.

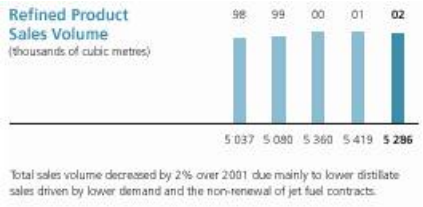
Wholesale and industrial gasoline and distillates sales were approximately 33% of EM&R's refined product sales in 2002. The remaining 5% was comprised of petrochemicals sold through Sun Petrochemicals Company, a 50% joint venture between a Suncor subsidiary and a U.S. based company.

Prior to April 2002, EM&R also marketed natural gas to approximately 125,000 commercial and residential customers in Ontario. EM&R divested its Ontario retail natural gas marketing business during the second quarter of 2002 in order to focus on its core refined products business.

Summary of Results

Year ended December 31

($ millions unless otherwise noted)	2002	2001	2000
Revenue	**2 361**	2 588	2 604
Refined product sales (thousands of cubic metres)			
Sunoco retail gasoline	**1 642**	1 575	1 539
Total	**5 286**	5 419	5 360
Net earnings (loss) breakdown:			
Rack Back	**10**	47	69
Rack Forward	**16**	23	(1)
Gain on sale of retail natural gas marketing business	**35**	—	—
Tax adjustments	**—**	10	13
Total net earnings	**61**	80	81
Cash flow provided from operations	**107**	165	174
Investing activities	**34**	71	59
Net cash surplus	**63**	111	155
ROCE (%)	**12.5**	18.4	20.5



Analysis of Net Earnings

EM&R's 2002 net earnings were $61 million, compared with $80 million in 2001. Excluding the net earnings effects of the gain on the sale of the retail natural gas marketing business, net earnings were $26 million in 2002, compared to $80 million in 2001. This decrease was primarily due to reduced refining margins and higher cash operating costs, partially offset by the benefits of higher refinery crude utilization. Net earnings in 2002 were also lower compared to 2001 as 2001 earnings included the positive impact of a tax rate reduction on EM&R's future income tax liabilities.

Rack Back

Net earnings for **Rack Back** were $10 million in 2002, compared with $47 million in 2001, including the impact of a $9 million gain on liquidation of excess natural gas supplies in 2001. The decrease was primarily due to lower refining margins and higher operating expenses, partially offset by improved refinery yield.

Rack Back and Rack Forward

EM&R's financial reporting is based on its Rack Back/Rack Forward organizational structure. The Rack Back division includes the procurement and refining of crude oil and feedstock, and sales and distribution to the Sarnia refinery's largest industrial and reseller customers. Rack Forward includes retail operations, cardlock and industrial/commercial sales, and the UPI and Pioneer joint venture businesses.

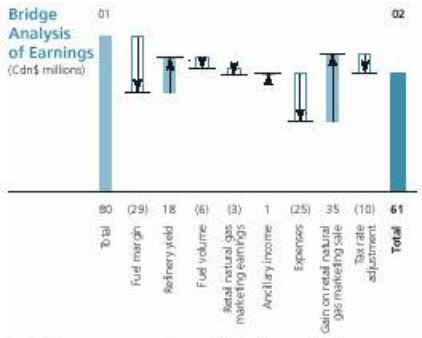
Refining margins decreased 16% to 4.8 cents per litre (cpl) in 2002, compared to 5.7 cpl in 2001, reflecting weak gasoline and distillates margins across North America. Lower margins reduced earnings for 2002 by $32 million, more than offsetting an $18 million improvement in earnings due to higher refinery yield and lower product purchase costs.

Rack Back sales volumes (including volumes sold to the Rack Forward business) averaged 14,500 cubic metres per day (91,100 bpd), down from 14,800 cubic metres per day (93,400 bpd) in 2001. Reduced sales volumes reflect the non-renewal of jet fuel contracts and lower distillate sales driven by weakened demand, partially offset by higher gasoline and petrochemical sales volumes. This resulted in a decline in Rack Back earnings of $3 million compared to 2001. EM&R's refined product market share in its primary market of Ontario declined to 17% in 2002, compared to 18% in 2001. Approximately 86% of EM&R's refined products were sold to the Ontario market in 2002.

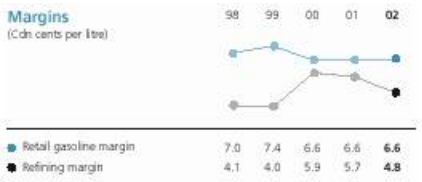
In addition to a 34-day planned maintenance shutdown on a portion of the refinery's operations in the second quarter, there were a number of unplanned outages in 2002 that affected plant availability. Following planned and unplanned maintenance work, all units returned to normal performance level with an improved crude utilization rate of 100% and 108% in the last two quarters of 2002, respectively. Overall, the refinery's crude utilization averaged 95% in 2002, compared to 92% in 2001. Despite additional product purchases that were made to satisfy customer

demand during the planned and unplanned periods of lower production, total product purchases made in 2002 were lower compared to 2001 due to the improvement in refinery reliability.

Rack Back's after-tax expenses were $20 million higher in 2002 compared to 2001, due in part to higher employee future benefits of $4 million, higher electricity costs of $3 million due to deregulation of the Ontario electricity market and increased maintenance and other general and administrative expenses. Expenses were also higher in 2002 compared to 2001 as 2001 results included a $9 million gain on liquidation of excess natural gas supplies.



Reduced downstream margins, lower fuel sales volumes and higher expenses were partially offset by improved refinery yield and a gain on the sale of the retail natural gas marketing business. No tax adjustment was recorded in 2002.



The refining margin declined 16% from 2001 in response to weakened demand and high inventory levels in North America. Retail gasoline margin remained stable relative to 2001.

Rack Forward

Rack Forward net earnings for 2002 increased to $51 million, compared to $23 million in 2001. Excluding the net earnings effect of a $35 million gain on the sale of the retail natural gas marketing business, Rack Forward net earnings decreased to $16 million compared to $23 million in 2001. The decrease was primarily attributable to lower earnings from the commercial and reseller sales channels and higher employee future benefits costs, which were partially offset by improved retail gasoline volumes. Also impacting Rack Forward's results was a $3 million reduction in retail natural gas marketing earnings over 2001. This business was sold at the beginning of the second quarter of 2002.

Gasoline sales volumes in the Sunoco-branded retail network grew by more than 4% in 2002 despite the closure of 19 sites, contributing to an earnings improvement of $2 million. Average site throughput was 5.8 million litres per site in 2002, a 7% improvement from the 5.4 million litres per site in 2001, reflecting continued improvement in network efficiency. EM&R's Ontario retail gasoline market share, including all Sunoco and joint venture operated retail sites, remained constant at 20%. EM&R's Sunoco- branded retail gasoline margin averaged 6.6 cpl, unchanged from 2001.

Royalty and **ancillary income** was $1 million higher than 2001, reflecting continued expansion of non-fuel products and services in the retail network. Due to aggressive price competition and commodity price volatility throughout 2002, earnings from the commercial and reseller sales channels declined by $2 million.

ancillary income
Income earned from non-fuel products and services such as car washes, sale of fast foods and confectionery items.

Rack Forward expenses were $5 million higher compared to 2001 primarily due to higher employee future benefits and higher marketing costs.

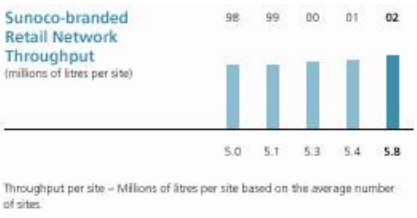
Net earnings from the retail joint ventures with Pioneer and UPI totalled $5 million in 2002, unchanged from 2001.

Net Cash Surplus Analysis

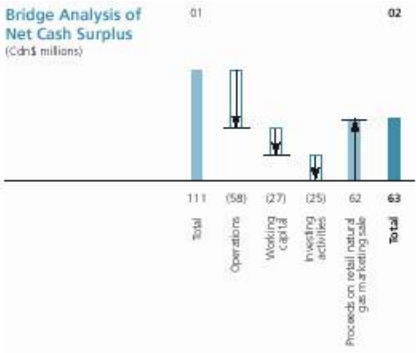
Cash flow from operations decreased to $107 million in 2002 from $165 million in 2001 as a result of lower earnings as described above. Working capital increased by $10 million in 2002, compared to a decline of $17 million in 2001 reflecting the impact of the sale of the retail natural gas marketing business and a net increase in trade receivables reflecting higher commodity prices.

Cash used in investing activities was $34 million in 2002, compared to $71 million in 2001. Higher capital spending and deferred maintenance costs in 2002 were more than offset by the $62 million net proceeds from the sale of the retail natural gas marketing business. Investing activities in 2002 also included $18 million for the planned maintenance shutdown at the Sarnia refinery, compared to $9 million in 2001.

The impact of these factors decreased the 2002 net cash surplus to $63 million, compared to $111 million in 2001.



Throughput per site – Millions of litres per site based on the average number of sites.



Net cash surplus declined by $48 million in 2002. Lower earnings led to reduced cash flow from operations. Increased working capital requirements and capital expenditures further reduced the net cash surplus. These reductions were partially offset by proceeds from the sale of the retail natural gas marketing business.

Outlook

To enhance competitiveness and to position the Sunoco-branded retail network for growth, EM&R plans to develop new Sunoco retail sites, upgrade existing facilities and close down low-volume, under-performing retail assets. EM&R will also target increased fuel and non-fuel revenue by focusing marketing initiatives on premium petroleum and ancillary offerings.

To further integrate the company's upstream and downstream businesses, EM&R continues to assess new marketing and refining investment opportunities to capture the greatest long term value from Suncor's Oil Sands production.

Regulation regarding low-sulphur gasoline specifications prescribes limits for sulphur levels in gasoline to an average of 150 parts per million (ppm) from mid-2002 to the end of 2004, and a maximum of 30 ppm by 2005. To meet these specifications, EM&R is constructing a desulphurization unit at the Sarnia refinery at an estimated cost of $40 million. The project is expected to be completed in 2003, more than a year ahead of the legislated deadline.

In 2002, the Canadian government passed legislation limiting the concentration of sulphur in diesel fuel produced or imported for use in on-road vehicles. The legislation places a limit on sulphur levels of 500 ppm until May 31, 2006 and a maximum of 15 ppm thereafter. Capital spending required by EM&Rfor compliance is estimated to be approximately $225 million from 2003 through 2005.

Risk/Success Factors Affecting Performance

Certain issues Suncor must manage that may affect performance of the EM&R business include, but are not limited to, the following:

- While EM&R's margins improved in the second half of 2002, management expects fluctuations in demand for refined products, margin and price volatility and market competitiveness, including potential new market entrants, will continue to impact the business environment.
- Environment Canada is expected to finalize regulations reducing sulphur in off-road diesel and light fuel oil to take effect later in the decade. Capital spending required is subject to the development of such regulations and strategic assessment. Several strategic options are being evaluated by EM&R to enhance integration with Oil Sands and increase value through integration with the diesel desulphurization facilities.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed below. Also refer to the Corporate Overview, Risk/Success Factors Affecting Performance on page 23.

Forward-looking Statement

This Management's Discussion and Analysis contains certain forward-looking statements that are based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of its experience and its perception of historical trends.

All statements that address expectations or projections about the future, including statements about Suncor's strategy for growth, expected and future expenditures, commodity prices, costs, schedules and production volumes, operating and financial results, are forward-looking statements. Some of the forward-looking statements may be identified by words like "expects," "anticipates," "plans," "intends," "believes," "projects," "indicates," "could," "vision," "goal," "target," "objective" and similar expressions. These statements are not guarantees of future performance and involve a number of risks, uncertainties and assumptions. Suncor's business is subject to risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor.
Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements as a result of known and unknown risks, uncertainties and other factors.

The risks, uncertainties and other factors that could influence actual results include: changes in the general economic, market and business conditions; fluctuations in supply and demand for Suncor's products; fluctuations in commodity prices; fluctuations in currency exchange rates; Suncor's ability to respond to changing markets; the ability of Suncor to receive timely regulatory approvals; the successful implementation of its

growth projects including the Firebag In-situ Oil Sands Project and Voyageur; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development; future environmental laws; the accuracy of Suncor's production estimates and production levels and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures; actions by governmental authorities including increasing taxes, government fees, changes in environmental and other regulations; the ability and willingness of parties with whom Suncor has material relationships to perform their obligations to Suncor; and the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor. Many of these risk factors are discussed in further detail throughout this Management's Discussion and Analysis and in the company's Annual Information Form/Form 40-F on file with the Alberta Securities Commission and certain other securities regulatory authorities. Readers are also referred to the risk factors described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

EXHIBIT 4

Excerpts from pages 2 to 6 inclusive of Suncor Energy Inc.'s Management Proxy Circular dated February 27, 2003

ELECTION OF DIRECTORS

Suncor's Articles of Incorporation stipulate that there shall be not more than fifteen nor fewer than eight directors. There are currently eleven directors. In accordance with the Company's By-laws, the Board of Directors has determined that twelve directors will be elected at the Meeting.

Suncor's management will propose at the Meeting that the twelve nominees named herein be elected directors. The term of office of each director is from the date of the meeting at which he or she is elected or appointed until the next annual meeting of shareholders or until a successor is elected or appointed.

Unless it is specified in a proxy that the Common Shares it represents shall be withheld from voting in the election of directors, the persons named in the accompanying form of proxy intend to vote for the election of the nominees whose names appear in the table below.

The Board of Directors is required to have an Audit Committee. The Board of Directors also has a Board Policy, Strategy Review and Governance Committee, a Human Resources and Compensation Committee, and an Environment, Health and Safety Committee. For details of the membership and mandates of these committees, see the notes to the table below, "Report on Executive Compensation" and "Statement of Corporate Governance Practices".

Management does not expect that any of the nominees will be unable to serve as a director but, if that should occur for any reason prior to the Meeting, the persons named in the accompanying proxy reserve the right to vote for another nominee at their discretion unless the proxy specifies that the Common Shares are to be withheld from voting in the election of directors.

Information for each person proposed to be nominated for election as a director is as follows:

MEL BENSON(1)(2) Calgary, Alberta Periods of Service as a Director: April 19, 2000 to present Common Shares(3): 4,780 Deferred Share Units(4): 1,919 Directors' Options(8): 24,000	Mel Benson is President of Mel E. Benson Management Services Inc., an international management consulting firm based in Calgary, Alberta. From 1996 to 2000 Mr. Benson was the Senior Operations Advisor, African Development, Exxon Co. International. Mr. Benson is also an active member of several charitable and Aboriginal organizations including the Counsel for Advancement of Native Development Officers, the Canadian Aboriginal Professional Association and the National Aboriginal Business Association.
BRIAN A. CANFIELD(5)(6) Point Roberts, Washington Periods of Service as a Director: November 10, 1995 to present Common Shares(3): 7,000 Deferred Share Units(4): 9,794 Directors' Options(8): 72,000	Brian Canfield is the Chairman of TELUS Corporation, a telecommunications company. In addition to serving on the Suncor Energy Inc. Board of Directors, Mr. Canfield is also on the boards of BC Gas Inc., Trans Mountain Pipe Line Ltd. and the Toronto Stock Exchange.
SUSAN E. CROCKER Toronto, Ontario Periods of Services as a Director: Nominee Director Common Shares(3): Nil	Susan Crocker is a corporate director and management consultant who serves as a director on the board of Brascan Financial Corporation and on the board of RioCan Real Estate Investment Trust. Ms. Crocker also serves as a director of a number of arts and community organizations, including Canadian Stage Theatre Company, the AGO Foundation Board and the Toronto Community Foundation.

Deferred Share Units(4): Nil Directors' Options(8): Nil	She is a Managing Director and founder of IQ Alliance, a strategic advisory firm formed in 2002. From 1996 to 1999 she was Senior Vice President, Equity and Derivative Markets with The Toronto Stock Exchange and from 1999 to 2001 was the President and Chief Executive Officer of the Hospitals of Ontario Pension Plan.

BRYAN P. DAVIES(1)(2)
Etobicoke, Ontario

Periods of Service as a
Director: January 28, 1991 to April 23, 1996, and April 19, 2000 to present

Common Shares(3): 12,400

Deferred Share Units(4): 5,785

Directors' Options(8): 32,000

Bryan Davies is Superintendent of the Financial Services Commission of Ontario, an agency of the Ontario Ministry of Finance that regulates insurance, pension and deposit institutions. Prior to that he was Senior Vice President, regulatory affairs with the Royal Bank of Canada. Mr. Davies is also active in a number of not-for-profit charitable and professional organizations. He is a member of Council for the Champlain Society, is Chair of the Canadian Merit Scholarship Foundation, and is currently a director and Treasurer of the Ontario Heritage Foundation.

BRIAN FELESKY(1)(2)
Calgary, Alberta

Periods of Service as a
Director: April 26, 2002 to present

Common Shares(3): 5,270

Deferred Share Units(4): 505

Directors' Options(8): 16,000

Brian Felesky is a partner in the law firm of Felesky Flynn in Calgary, Alberta. Mr. Felesky also serves as a director on the board of TransCanada Power LP. Mr. Felesky is actively involved in not-for-profit and charitable organizations. He is the Chair of Homefront on Domestic Violence, a director of the United Way of Calgary & Area and the Canada West Foundation, as well as a member of the Board of Governors of the Council for Canadian Unity.

JOHN T. FERGUSON(2)(6)
Edmonton, Alberta

Periods of Service as a
Director: November 10, 1995 to present

Common Shares(3): 16,845

Deferred Share Units(4): 5,163

Directors' Options(8): 72,000

John Ferguson is Chairman of the Board of Princeton Developments Ltd., a real estate company in Edmonton, Alberta, as well as Chairman of the Board of TransAlta Corporation in Calgary, Alberta. Mr. Ferguson is also a director of Bellanca Developments Ltd. and the Royal Bank of Canada. In addition, he is also a director of the C.D. Howe Institute and the Canadian Institute for Advanced Research. His involvement in the community includes Chancellor of the University of Alberta.

RICHARD L. GEORGE(6)(7)
Calgary, Alberta

Periods of Service as a
Director: February 1, 1991 to present

Common Shares(3): 198,554

Deferred Share Units(4): 200,990

Directors' Options(8): N/A

Richard George is the President and Chief Executive Officer of Suncor Energy Inc. Mr. George is also a director of Enbridge Inc., Dofasco Inc., and the U.S. offshore and onshore drilling company, GlobalSantaFe Corporation.

JOHN R. HUFF(5)(6)
Houston, Texas

Periods of Service as a
Director: January 30, 1998 to present

Common Shares(3): 20,792

Deferred Share Units(4): 10,280

Directors' Options(8): 48,000

John Huff is Chairman and Chief Executive Officer of Oceaneering International Inc., an oil field services company. Mr. Huff is also a director of BJ Services Company. He is also active in a variety of non-profit organizations, serving as a director for the American Bureau of Shipping and the Marine Resources Foundation, Key Largo. He is also a trustee for the Houston Museum of National Science.

ROBERT W. KORTHALS(2)(6)
Toronto, Ontario

Periods of Service as a
Director: April 23, 1996 to present

Common Shares(3): 16,000

Deferred Share Units(4): 9,337

Directors' Options(8): 64,000

Robert Korthals is the former President of the Toronto-Dominion Bank. He is currently Chairman of the board of directors of the Ontario Teachers' Pension Plan, and also is a director of Jannock Properties Limited, Rogers Communications Inc., RTO Inc., Cognos Inc., Gerdau-Ameristeel Inc. and several publicly traded investment funds sponsored by Mulvihill Investments. He is also a commissioner with the Ontario Securities Commission, and in addition, serves as a director of the Canadian Parks and Wilderness Foundation.

M. ANN MCCAIG(1)(5)
Calgary, Alberta

Periods of Service as a
Director: October 1, 1995 to present

Common Shares(3): 10,329

Deferred Share Units(4): 10,770

Directors' Options(8): 72,000

Ann McCaig is the President of VPI Investments Ltd., a private investment holding company. Ms. McCaig is actively involved with charitable and community activities. She is currently Chair of the Alberta Adolescent Recovery Centre, the Co-chair of the Alberta Children's Hospital Foundation All for One — All for Kids $50 million Campaign, and a trustee of the Killam Estate. She is also Chancellor Emeritus of the University of Calgary.

MICHAEL O'BRIEN(1)
Canmore, Alberta

Periods of Service as a
Director: April 26, 2002 to present

Common Shares(3): 9,347

Deferred Share Units(4): none

Directors' Options(8): none

Michael O'Brien is the former Executive Vice President, Corporate Development and Chief Financial Officer of Suncor Energy Inc., having retired in 2002. Prior to that, Mr. O'Brien was Executive Vice President of Suncor's wholly-owned subsidiary, Suncor Energy Products Inc. (formerly Sunoco Inc.) from 1992 to 2000. Mr. O'Brien also serves on the boards of directors of PrimeWest Energy Inc. and BC Gas Inc. In addition, he is currently Chair of the board of trustees for Nature Conservancy Canada.

JR SHAW(5)(6)
Calgary, Alberta

Periods of Service as a
Director: January 30, 1998 to present

Common Shares(3): 191,900

Deferred Share Units(4): 20,177

Directors' Options(8): 48,000

JR Shaw has been the Chairman of the Board of Suncor Energy Inc. since 2001. He is also the Executive Chair of Shaw Communications Inc., the cable television company he founded in 1966. Mr. Shaw is also a director of Canadian Hydro Developers, Inc. and a director of the Shaw Foundation.

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(1) Member of the Environment, Health and Safety Committee.

(2) Member of the Audit Committee.

(3) "Common Shares" refers to the number of Common Shares beneficially owned, or over which control or direction is exercised by, the director as at February 27, 2003. The information relating to holdings of Common Shares, not being within the knowledge of Suncor, has been furnished by the respective nominees individually. Fractional Common Shares have been excluded from the numbers shown. The number of Common Shares held by Mr. George includes 164,972 Common Shares over which he exercises control or direction but which are beneficially owned by members of his family. Certain Common Shares held by Mr. Benson (400) are beneficially owned by his spouse. The number of Common Shares held by Mr. Shaw includes Common Shares over which he exercises control or direction, but which are beneficially owned jointly by Mr. Shaw and his spouse (13,900), Common Shares beneficially owned by his spouse (10,000), and Common Shares beneficially owned by his company (24,000).

(4) Deferred Share Units (DSUs) are not voting securities but are included in this table for informational purposes. See "Compensation of Directors" for a description of DSUs. The number of DSUs for each director is as at February 27, 2003, and fractional DSUs have been excluded from the numbers shown.

(5) Member of the Human Resources and Compensation Committee.

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(6) Member of the Board Policy, Strategy Review and Governance Committee. Mr. George was a member of this committee until November 14, 2002.

(7) Mr. George also serves as director and/or officer of certain subsidiaries of Suncor.

(8) Directors' options are not voting securities but have been included in this table for informational purposes. Directors' options comprise only options granted to non-employee directors, as described under the heading, "Compensation of Directors". Directors' options do not include options granted to executives and former executives in their capacities as such under Suncor's Executive Stock Plan and Sunshare Performance Stock Option Plan, respectively (together, the "Executive Plans"). Options held by Mr. George under the Executive Plans are reported in the table on page 15. Mr. O'Brien, a former executive of Suncor, holds 179,656 options granted to him under the Executive Plans while employed as an executive of Suncor. All of Mr. O'Brien's Executive Options expire on the earlier of their stated expiry date, or in July 2005, on the third anniversary of his retirement.

EXHIBIT 5

Consent of PricewaterhouseCoopers LLP



PricewaterhouseCoopers LLP
Chartered Accountants
111 5th Avenue SW, Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 (403) 509 7500
Facsimile +1 (403) 781 1825

Consent of Independent Accountants

We hereby consent to the incorporation by reference in this Annual Report on Form 40-F and the incorporation by reference in the registration statements on Form F-3 (File No. 333-7450), Form F-10 (File No. 333-14242), and on Form S-8 (File No. 333-87604), of Suncor Energy Inc. of our report dated January 17, 2003 relating to the consolidated financial statements, which appears in the Annual Report to Shareholders.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Accountants
Calgary, Alberta
March 27, 2003

PricewaterhouseCoopers refers to the Canadian firm of PricewaterhouseCoopers LLP and the other member firms of PricewaterhouseCoopers International Limited, each of which is a separate and independent legal entity.

EXHIBIT 6

Consent of Gilbert Laustsen Jung Associates Ltd.

Gilbert Laustsen Jung
Associates Ltd. Petroleum Consultants
4100, 400 – 3rd Avenue S.W., Calgary, Alberta, Canada T2P 4H2 (403) 266-9500 Fax (403) 262-1855

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of each Province of Canada

Re: Suncor Energy Inc.

We refer to the following reports prepared by Gilbert Laustsen Jung Associates Ltd.:

- the letter reports dated January 15, 2003, as to the synthetic crude oil reserves effective December 31, 2002 associated with the Suncor Energy Inc. oil sands operations located near Fort McMurray, Alberta;
- the letter report dated January 24, 2003 as to the Firebag Project effective December 31, 2002;
- the Reserve Determination and Evaluation of the Canadian Oil and Gas Properties of Suncor Energy Inc. Natural Gas effective December 31, 2002, dated January 28, 2003;
- the Suncor Energy Inc. Natural Gas Constant Price Analysis effective December 31, 2002, dated January 22, 2003;

(collectively the “Reports”)

We hereby consent to the use of our name, reference to and excerpts from the said reports by Suncor Energy Inc. in its Annual Information Form for the 2002 fiscal year (AIF) and its annual report on Form 40-F (Form 40-F), including Exhibit 1, Proved Oil and Gas Reserves Quantities, thereto, and the registration statements of Suncor Energy Inc. on Form F-3 (File No. 333-7450), Form F-10 (File No. 333-14242) and Form S-8 (File No. 333-87604).

We have read the AIF and the Form 40-F and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Reports or that are within our knowledge as a result of the services which we performed in connection with the preparation of the Reports.

Yours very truly,

GILBERT LAUSTSEN JUNG
ASSOCIATES LTD.

ORIGINALLY SIGNED BY

Wayne W. Chow, P. Eng.
Vice-President

Calgary, Alberta
Date: March 27, 2003

EXHIBIT 7

Certificate of the President and Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

The following certifications accompany the annual report on Form 40-F pursuant to 18 U.S.C. Section 1350, as enacted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, and shall not, except to the extent required by 18 U.S.C. Section 1350, as enacted pursuant to the Sarbanes-Oxley Act of 2002, be deemed filed by Suncor Energy Inc. for the purposes of Section 18 of the Securities Exchange Act of 1934.

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Suncor Energy Inc. (the "Registrant"), is filing its annual report on Form 40-F for the fiscal year ended December 31, 2002 (the "Report") with the Securities and Exchange Commission.

I, RICHARD L. GEORGE, President and Chief Executive Officer of the Registrant, certify, pursuant to 18 U.S.C. section 1350, as enacted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

(i) the Report fully complies with the requirements of section 13(a) or 15(d) of the Exchange Act; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of the operations of the Registrant.

"RICHARD L. GEORGE"
RICHARD L. GEORGE
President and Chief Executive Officer
Suncor Energy Inc.

DATE: April 3, 2003

EXHIBIT 8

Certificate of the Executive Vice President, Corporate Development and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

The following certifications accompany the annual report on Form 40-F pursuant to 18 U.S.C. Section 1350, as enacted pursuant to of the Sarbanes-Oxley Act of 2002, and shall not, except to the extent required by 18 U.S.C. Section 1350, as enacted pursuant to the Sarbanes-Oxley Act of 2002, be deemed filed by Suncor Energy Inc. for the purposes of Section 18 of the Securities Exchange Act of 1934.

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Suncor Energy Inc. (the "Registrant"), is filing its annual report on Form 40-F for the fiscal year ended December 31, 2002 (the "Report") with the Securities and Exchange Commission.

I, STEVEN W. WILLIAMS, Executive Vice President, Corporate Development and Chief Financial Officer of the Registrant, certify, pursuant to 18 U.S.C. section 1350, as enacted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

(i) the Report fully complies with the requirements of section 13(a) or 15(d) of the Exchange Act; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of the operations of the Registrant.

"STEVEN W. WILLIAMS"
STEVEN W. WILLIAMS
Executive Vice President, Corporate
Development and Chief Financial Officer
Suncor Energy Inc.

DATE: April 3, 2003
