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, 2004**

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**	**98-0343201**
(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	**As of December 31, 2004 there were 454,240,626 Common Shares issued and outstanding**
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 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

SUNCOR ENERGY INC. ANNUAL INFORMATION FORM

March 21, 2005

ANNUAL INFORMATION FORM

TABLE OF CONTENTS

TABLE OF CONTENTS ii
GLOSSARY OF TERMS iv
CONVERSION TABLE viii
CURRENCY viii
FORWARD-LOOKING STATEMENTS viii
NON GAAP FINANCIAL MEASURES ix
CORPORATE STRUCTURE 1
- Name and Incorporation 1
- Intercorporate Relationships 1

GENERAL DEVELOPMENT OF THE BUSINESS 2
- Overview 2
- Three-Year History 3

OIL SANDS (OS) 8
- Operations 8
- Principal Products 9
- Transportation 9
- Competitive Conditions 9
- Seasonal Impacts 9
- Sales of Synthetic Crude Oil and Diesel 10
- Environmental Compliance 10

NATURAL GAS (NG) 10
- Marketing, Pipeline and Other Operations 11
- Principal Products 11
- Competitive Conditions 12
- Environmental Compliance 12

ENERGY MARKETING & REFINING – CANADA (EM&R) 12
- Procurement of Feedstocks 13
- Refining Operations 13
- Principal Products 14
- Principal Markets 15
- Transportation and Distribution 15
- Competitive Conditions 16
- Environmental Compliance 16

REFINING & MARKETING – U.S.A. (R & M) 16
- Procurement of Feedstocks 16
- Refining Operations 16
- Principal Products 17
- Principal Markets 17
- Transportation and Distribution 18
- Competitive Conditions 18
- Environmental Compliance 19

MATERIAL CONTRACTS 19
RESERVES ESTIMATES 19
REQUIRED U.S. OIL AND GAS AND MINING DISCLOSURE 21
- Proved and Probable Oil Sands Mining Reserves 21
- Oil Sands Mining Operating Statistics 22
- Proved Conventional Oil and Gas Reserves 22
- Capitalized Costs Relating to Oil and Gas Activities 24
- Costs Incurred in Oil and Gas Acquisition, Exploration and Developmental Activities 24
- Results of Operations for Oil and Gas Production 25
- Standardized Measure of Discounted Future Net Cash Flows from Estimated Production of Proved Oil and Gas Reserves after Income Taxes 25
- 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 26
- Sales, Production, Well Data, Land Holdings and Drilling Activity - Conventional 26

Future Commitments to Sell or Deliver Crude Oil and Natural Gas 29
VOLUNTARY OIL SANDS RESERVES DISCLOSURE 29
Oil Sands Mining and In-Situ Firebag Reserves Reconciliation 29
SUNCOR EMPLOYEES 31
RISK/SUCCESS FACTORS 31
SELECTED CONSOLIDATED FINANCIAL INFORMATION 37
Selected Consolidated Financial Information 37
Dividend Policy and Record 38
MANAGEMENT'S DISCUSSION AND ANALYSIS 39
DESCRIPTION OF CAPITAL STRUCTURE 39
General Description of Capital Structure 39
Ratings 39
MARKET FOR OUR SECURITIES 40
Price Range and Trading Volume of Common Shares 41
DIRECTORS AND EXECUTIVE OFFICERS 41
Directors 41
Executive Officers 41
Additional Disclosure for Directors and Executive Officers 42
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS 43
TRANSFER AGENT AND REGISTRAR 43
INTERESTS OF EXPERTS 43
FEES PAID TO AUDITORS 44
Fees Paid to Auditors 44
Audit Committee Pre-Approval Policies for Non Audit Services 44
RELIANCE ON EXEMPTIVE RELIEF 44
LEGAL PROCEEDINGS 45
ADDITIONAL INFORMATION 45

GLOSSARY OF TERMS

Bitumen/Heavy Oil

A naturally occurring viscous tar-like mixture, mainly containing hydrocarbons heavier than pentane, which 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.

Developed Reserves

Developed reserves are those proved reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production.

Downstream

These business segments manufacture, distribute and market 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

Suncor's undivided percentage interest in production/reserves, as the case may be, 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 23, 2005, 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, 2004, which 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, 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[(1)]

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely [(2)] that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(1) We are subject to Canadian disclosure rules in connection with the reporting of reserves. However, we have received exemptive relief from Canadian securities administrators permitting us to report our proved reserves in accordance with U.S. disclosure practices. In addition, although U.S. companies do not disclose probable reserves for non-mining properties, we voluntarily disclose probable reserves for our Firebag in-situ leases as we believe this information is useful to investors. See "RESERVES ESTIMATES" on page 19 for a description of how our voluntary reserves disclosure differs from our U.S. required disclosure.

(2) In estimating our proved and probable reserves, our independent reserves evaluators, GLJ, have targeted the following levels of certainty: at least 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves. However, as our reserves have been prepared using deterministic, rather than probabilistic methods, consistent with industry practice, GLJ's estimates do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Proved oil and gas reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty(2) to be recoverable in future years from known reservoirs under assumed economic and operating conditions. For a discussion of pricing assumptions see the tables under the headings "REQUIRED US OIL AND GAS AND MINING DISCLOSURE – Proved Conventional Oil and Gas Reserves" and under "VOLUNTARY OIL SANDS RESERVES DISLOSURE - Oil Sands Mining and In-Situ Firebag Reserves Reconciliation".

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved Producing Reserves

Proved producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

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

Undeveloped acreage is considered to be lands on which wells have not been drilled or completed to a point that would permit production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves.

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 the 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. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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.

Return on Capital Employed (ROCE)

Net earnings adjusted for after-tax financing expenses or income for the twelve-month period ended December 31; divided by average capital employed. Average capital employed is the sum of shareholders’ equity and short-term debt plus long-term debt, less cash and cash equivalents, at the beginning and end of the year, divided by two, less average capitalized costs related to major projects in progress (as applicable). See “Non GAAP Financial Measures”, on page ix.

Return on Average Shareholders’ Equity

Net earnings as a percentage of average shareholders’ equity. Average shareholders’ equity is the sum 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 cubic metre m^3 (natural gas) = 35.49 cubic feet
1 cubic metre m^3 (overburden) = 1.31 cubic yards

1 tonne = 0.984 tons (long)
1 tonne = 1.102 tons (short)
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 our current expectations, estimates, projections and assumptions that we’ve made in light of our experience.

All statements that address expectations or projections about the future, including statements about our strategy for growth, expected future expenditures, commodity prices, costs, schedules, production volumes, operating and financial results and expected impact of future commitments, are forward-looking statements. Some of the forward-looking statements may be identified by words like “expects,” “anticipates,” “estimate”, “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 and uncertainties, some that are similar to other oil and gas companies and some that are unique to our experience. Our actual results may differ materially from those expressed or implied by our 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 the general economic, market and business conditions; fluctuations in supply and demand for our products; commodity prices and currency exchange rates; our ability to respond to changing markets, and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects (for example the continued investment in our Firebag in-situ development project) and regulatory projects (for example, the clean fuels refinery modifications projects in our downstream businesses); the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement of conception of the detailed engineering needed to reduce the margin of error or level of accuracy; the integrity and reliability of our capital assets; the cumulative impact of other resource development; future environmental laws; the

accuracy of our reserve, resource and future production estimates and our 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 and from companies that provide alternative sources of energy; the uncertainties resulting from the January 2005 fire at the oil sands facility and other uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties; changes in environmental and other regulations; the ability and willingness of parties with whom we have material relationships to perform their obligations to us; and the occurrence of unexpected events such as the recent fire, blowouts, freeze-ups, equipment failures and other similar events affecting us or other parties whose operations or assets directly or indirectly affect us. These 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 our MD&A, incorporated by reference herein. Readers are also referred to the risk factors described in other documents we file 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, or by referring to SEDAR at www.sedar.com, or by referring to EDGAR at www.sec.gov.

References herein to our 2004 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, 2004.

NON GAAP FINANCIAL MEASURES

Certain financial measures referred to in this AIF that are not prescribed by GAAP, namely, ROCE, cash flow from operations per common share and Oil Sands cash and total operating costs per barrel, are described and reconciled in the "Non GAAP Financial Measures", section of our MD&A, incorporated by reference herein.

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, we amalgamated with a wholly-owned subsidiary under the *Canada Business Corporations Act*. We amended our articles in 1995 to move our registered office from Toronto, Ontario, to Calgary, Alberta, and again in April 1997, to adopt our current name, "Suncor Energy Inc.". In April 1997, May 2000 and May 2002, we amended our articles to divide our issued and outstanding shares on a two-for-one basis.

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

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

Intercorporate Relationships

We have three principal subsidiaries.

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

Suncor Energy Marketing Inc., wholly-owned by Suncor Energy Products Inc., is incorporated under the laws of Alberta. We market, 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, through this indirect Suncor subsidiary. We also market, through this subsidiary, certain third party products, and procure crude oil feedstocks for Suncor's downstream businesses. Suncor Energy Marketing Inc. also has a petrochemical marketing division that holds a 50% interest in Sun Petrochemicals Company ("SPC"), a petrochemical products joint venture. In 2002, this subsidiary began procuring the natural gas supply for Suncor's Oil Sands and Energy Marketing and Refining businesses, and administering Suncor's energy trading activities. In 2003, this subsidiary began marketing certain natural gas volumes produced by, and purchased from, Suncor's Natural Gas business unit.

Suncor Energy (U.S.A.) Inc., indirectly wholly owned by Suncor Energy Inc., is incorporated under the laws of Delaware. Through this U.S. subsidiary, headquartered in Denver, Colorado, we refine crude oil at our refinery in Commerce City, Colorado, near Denver, into a broad range of petroleum products, and market our refined products to industrial, wholesale and commercial customers principally in Colorado and to retail customers in Colorado through Phillips 66 - branded sites. We also transport crude oil on our wholly or partly owned pipelines in Wyoming and Colorado.

Effective February 1, 2005, Suncor Energy Inc., as general partner and one of its wholly owned subsidiaries, as a limited partner, entered into a partnership, Suncor Energy Oil Sands Limited Partnership. The partnership holds certain net profits interests related to our oil sands business and natural gas business. This was an internal restructuring that has no effect on operations or on financial reporting.

We also have a number of other subsidiary companies. However, the total assets of such subsidiaries and partnerships 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

We are an integrated energy company, with corporate headquarters in Calgary, Alberta, Canada. We explore for, acquire, develop, produce and market crude oil and natural gas, transport and refine crude oil and market petroleum and petrochemical products. Periodically, we also market third party petroleum products. We also carry on energy trading activities focused principally on buying and selling futures contracts and other derivative instruments based on the commodities we produce.

We have four principal operating business units:

Our Oil Sands business unit, based near Fort McMurray, Alberta, recovers bitumen, primarily through oil sands mining and in-situ development, and upgrades it into refinery feedstock and diesel fuel. Bitumen feedstock is also occasionally supplemented by third party suppliers.

Our Natural Gas business unit, based in Calgary, Alberta, explores for, acquires, develops and produces natural gas from reserves in Western Alberta and Northeastern British Columbia. The sale of Natural Gas production provides a price hedge for natural gas purchased for consumption at our Oil Sands facility and our refineries in Sarnia, Ontario and near Denver, Colorado. In addition, our U.S. subsidiary, Suncor Energy (Natural Gas) America Inc., acquires land and explores for coal bed methane and conventional natural gas in the United States.

Our third business unit, Energy Marketing and Refining - Canada, headquartered in Toronto, Ontario, refines crude oil at Suncor's refinery in Sarnia, Ontario, into a broad range of petroleum products. These products are then marketed 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. We also engage in third party energy marketing and trading activities through this business unit.

Our fourth business unit, Refining and Marketing – U.S.A., headquartered in Denver, Colorado, refines crude oil at our refinery in Commerce City, Colorado, near Denver, into a broad range of petroleum products, and markets our refined products to industrial, wholesale and commercial customers principally in Colorado and to retail customers in Colorado through Phillips 66 - branded sites. We also transport crude oil on our wholly or partly owned pipelines in Wyoming and Colorado.

Finally, in addition to our hydrocarbon-based businesses, we pursue the development of low-emission and no-emission energy sources that have a reduced environmental impact. For financial reporting purposes, we report segmented financial data for these activities under the results of Suncor's "Corporate" segment.

In 2004, we produced approximately 263,300 BOE per day, comprised of 230,000 barrels per day (bpd) of crude oil and natural gas liquids and 200 million cubic feet per day of natural gas. In 2003, the most recent period with published results, we were the 5th largest crude oil and natural gas liquids producer (approximately 9% of Canada's crude oil production) and the 10th largest natural gas producer in Canada.

In 2004, we sold approximately 97,000 bpd (2003 – 94,400 bpd) or 15,400 m^3 per day (2003 – 15,000 m^3 per day) of refined products, mainly in Ontario but also in the United States and Europe through our Energy, Marketing & Refining business unit. Our refined product sales in Ontario represented approximately 19% (2003-19%) of Ontario's total refined product sales in 2004. In 2004, our Refining & Marketing business unit sold approximately 58,500 bpd or 9,300 m^3 of refined products in Colorado, including approximately 45,400 bpd or 7,200 m^3 per day of light oils (gasoline and distillates) (from August 1, 2003 to December 31, 2003, 56,900 bpd or 9,100 m^3 per day, including approximately 43,700 bpd or 7,000 m^3 per day of light oils). Our Refining & Marketing business unit supplies approximately 23% of Colorado's light oil product demand.

Three-Year History

Oil Sands (OS)

OS growth – In 2001, we completed Project Millennium, a $3.4 billion expansion that nearly doubled the production capacity of our operation to 225,000 bpd. During that same year, we also disclosed plans for a multi phased growth strategy designed to increase production capacity to 500,000 to 550,000 bpd by 2010 to 2012. Key components of this strategy include:

- Increasing bitumen supply through the development of the Firebag in-situ oil sands facility. The first phase of Firebag began producing bitumen in 2004 and we expect the second phase of Firebag to be completed in 2005.

- Increasing production capacity to 260,000 bpd in 2005 through the construction and commissioning of a new vacuum unit. The project, which is estimated to cost $425 million, is on schedule and on budget.

- Increasing production capacity to 350,000 bpd in 2008. This project is expected to reach several milestones during 2005 with fabrication and transport of major vessels expected to be completed during the year. The total cost of this project is estimated at $3.6 billion, including approximately $2.1 billion to expand Upgrader 2 and $1.5 billion to increase bitumen supply.

- In planning for expansion beyond 2008 and reaching the goal of 500,000 to 550,000 bpd, OS filed a regulatory application in March 2005 to construct a third upgrader and other facilities. Costs for this project are currently estimated at $5.9 billion. Approval of our Board of Directors is also required before the project can proceed.

Petro-Canada agreement - - Incremental bitumen to feed the expanded OS operation is also expected to be provided under a processing agreement between Suncor and Petro-Canada, slated to take effect in 2008. Under the agreement, we will process at least 27,000 bpd of Petro-Canada bitumen on a fee-for-service basis. Petro-Canada will retain ownership of the bitumen and resulting sour crude oil production of about 22,000 bpd. In addition, we will sell an additional 26,000 bpd of our proprietary sour crude oil production to Petro-Canada. Both the processing and sales components of the agreement will be for a minimum 10-year term.

Mine Extension – In March 2005 we also filed for approval to construct and operate an extension of the Steepbank mine. The proposed development would replace ore production that is expected to be depleted prior to the end of the decade. Currently, capital development costs are estimated at $350 million. Final approval from our Board of Directors is also required before construction can proceed. To support the company's mine development plan, we submitted a regulatory application in January 2005 to build a new primary extraction plant in closer proximity to our mining operations. The cost of constructing the new extraction facility and decommissioning the existing plant is estimated at $320 million.

Operating license renewal **-** During 2005, we will be required to update our ten year operating license by filing a renewal application with regulators. We do not expect the operating license renewal to affect our growth plans.

Kyoto Protocol - On December 17, 2002, the Government of Canada announced its ratification of the Kyoto Protocol. We continue to consult with governments about the impact of the Kyoto Protocol and plan to continue to actively manage our greenhouse gas emissions. We currently estimate that in 2010 the impact of the Kyoto Protocol on Oil Sands cash operating costs will be an increase of approximately $0.20 to $0.27 per barrel. Our estimates assume a reduction obligation of 15% from the 2010 business-

as-usual energy intensity [(3)] and that the maximum price for carbon credits would, as the Government of Canada indicated in 2002, be capped at $15 per tonne of carbon dioxide equivalents until 2012. Based on these assumptions, we do not currently anticipate that the cost implications of federal and provincial climate change plans will have a material effect on our business or future growth plans. The ultimate impact of Canada's implementation of the Kyoto Protocol remains subject to numerous risks, uncertainties and unknowns, and it is not possible to predict how these and other Kyoto related issues will ultimately be resolved.

Oil Sands Fire - A fire on January 4, 2005 caused significant damage to one of our two upgraders, reducing upgraded crude oil production capacity of 225,000 bpd from base operations to about 110,000 bpd. Repair work is underway and we expect our Oil Sands operations to return to full production capacity in the third quarter of 2005. The timeline for recovery work is preliminary and subject to change. Further inspection of the damaged equipment will occur as the repairs progress. Any new information could modify the timetable for returning to full production. To mitigate the impact of reduced production during the recovery period, we plan to bring forward as many maintenance projects as possible, including all, or significant portions of, a maintenance shutdown previously planned for the fall of 2005. Our preliminary findings into the cause of the fire suggest the issue was of an isolated nature. For additional information on our insurance policies refer to note 11 to our consolidated financial statements as well as "Significant Developments in 2004 and Subsequent Event" in the "Suncor Overview and Strategic Priorities" section of our MD&A which is incorporated by reference herein.

Natural Gas (NG)

Simonette Gas Plant - - In November 2004, our Natural Gas business unit divested of 62.5% of its interest in the Simonette gas plant for proceeds of $19 million. We retain a 37.5% ownership and continue to operate the gas plant. We, along with our partner are in the process of expanding the capacity of the plant and building a new pipeline to connect the facility with volumes produced from the Cabin Creek and Solomon fields in the Alberta Foothills.

Land Acquisition - - In December 2004, our Natural Gas business unit acquired assets in eastern British Columbia for $33 million. These assets generate approximately 6 mmcf/d of production, and consist of developed and undeveloped land.

Frontier Disposition - During 2003, our Natural Gas business unit disposed of our interest in Frontier properties (the Arctic and Northwest Territories) including 28 long-term "significant discovery licenses". There was no production from these interests.

Other Events - Also in December 2004, our Natural Gas business unit paid $18 million as a final arbitrated settlement relating to the termination of gas marketing contracts related to Enron Corporation's bankruptcy in December 2001.

Energy Marketing & Refining - Canada (EM&R)

Sarnia Regional Co-Generation Project - 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, supplies all of the steam and electricity requirements of EM&R's Sarnia Refinery in excess of that produced on-site using waste energy. The agreement mitigates EM&R's exposure to increases in energy costs and provides a supply of steam to the Sarnia Refinery at a competitive cost, while eliminating the need for EM&R to build its own steam generating boilers.

Sale of Retail Natural Gas Marketing Business - - In 2002, to focus on refining and marketing, EM&R sold its retail natural gas marketing business, resulting in an after-tax gain of $35 million. At the time of sale, the business was supplying natural gas to approximately 125,000 commercial and residential customer

(3) Reflects the level of greenhouse gas emissions that would have occurred in the absence of energy efficiency and process improvements after 2000.

accounts in Ontario.

Desulphurization Projects – Canadian 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. Construction of the 10,250 barrels per day capacity gasoline desulphurization unit was completed in the fourth quarter of 2003 with the unit placed into service before the 2003 year-end, at a cost of $44 million.

In 2002, the Canadian government 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, by June 1, 2006. The current maximum is 500 ppm. To meet these requirements, in October 2003, we and Shell Canada Products Inc. ("Shell") entered into a 20-year agreement under which we will build hydrotreating facilities at our Sarnia refinery to process high-sulphur diesel from both Shell's and our Sarnia refineries, to produce low sulphur diesel in compliance with the new on-road diesel limits. Under the agreement Shell will pay us a processing fee. Operating a single hydrotreating unit, instead of two separate units, is expected to result in cost benefits to us and Shell, as well as environmental benefits for the Sarnia-Lambton community as one larger unit is expected to consume comparatively less energy and have lower greenhouse gas emissions. Construction of the diesel desulphurization facilities commenced in 2004, and project completion is expected in early 2006.

Regulations reducing sulphur in off-road diesel and light fuel oil are also expected to take effect later in the decade. We believe that if the regulations are finalized as currently proposed, the new diesel desulphurization facilities for reducing sulphur in on-road diesel, should also allow us to meet the requirements for reducing sulphur in off-road diesel and light fuel oil.

In combination with the diesel desulphurization project, we are planning to expand the refinery's throughput capacity, enabling it to process approximately 40,000 bpd of Oil Sands sour crude blends. These modifications, as currently envisioned, are expected to lower feedstock costs over the long term. When all components of this project are completed in 2007, Suncor expects this project will cost approximately $800 million.

Ethanol Plant - In 2004, Suncor completed pre-development engineering, formal public consultation, preliminary project plans and regulatory application submissions for the planned ethanol plant in the Sarnia region. We also finalized the site location for the development of the plant. This facility is expected to produce ethanol at a capacity of 200 million litres per year for blending into our Sunoco-branded fuels and fuels sold through our joint venture operated networks. Construction of the facility is expected to begin in 2005 and the cost is currently estimated to be $120 million. In February 2004, we received approval from the Federal Government's Natural Resources Canada's Ethanol Expansion Program on our funding proposal for the project, which, subject to final approvals, will contribute $22 million towards our construction of the facility.

Energy Marketing & Trading - - In 2001, we commenced a physical energy marketing business to generate additional income by marketing third party crude oil and bitumen. This activity resulted in net pretax gains of $12 million in 2004 compared to $2 million in 2003 and $6 million for the year ended December 31, 2002.

In 2002, Suncor's Board of Directors approved commencement of financial derivatives trading activities ("energy trading") and after developing an appropriate control framework, we began limited energy trading activities in November 2002. A separate risk management function monitors practices and policies and provides independent verification and valuation of our trading and marketing activities. Trading activities are principally focused on the commodities we produce, adding potential for increased revenue and providing increased insight into global energy markets. Net financial trading losses, before taxes and general and administrative expenses, were negligible for the two month period ended December 31, 2002, $3 million for the year ended December 31, 2003, and net trading gains, before taxes and general and administrative expenses, were $11 million before tax for the year ended December 31, 2004.

Refining & Marketing – U.S.A. (R & M)

On August 1, 2003, we acquired a Denver refinery and related pipeline and retail assets from ConocoPhillips Company ("ConocoPhillips"). The acquisition was made with the expectation of providing us with the flexibility to move additional Oil Sands production into the U.S. marketplace. By December 31, 2004 we were processing approximately 6,000 bpd of Oil Sands crude oil at our Denver refinery. We paid US$150 million (about Cdn$210 million) for the assets, plus approximately US$44 million (about Cdn$62 million) for crude oil, product inventories and other closing adjustments. The acquisition included:

- a 60,000 bpd refinery located in the Denver area;

- 43 Phillips 66 - branded retail stations, primarily in the Denver area, plus contract agreements with approximately 150 Phillips-branded marketer outlets throughout Colorado; and

- the Rocky Mountain and Centennial pipeline systems, located in Wyoming and Colorado. Suncor has 100% ownership of the 480 kilometre (300 mile) Rocky Mountain pipeline system and 65% ownership of the 140 kilometre (87 mile) Centennial pipeline system.

As part of the agreement to acquire these assets, Suncor assumed obligations of ConocoPhillips at the refinery pursuant to a Consent Decree with the United States Environmental Protection Agency, the United States Department of Justice and the State of Colorado. These obligations are expected to require expenditures of Cdn$29 million (approximately US$24 million) through 2006. The expenditures, intended to reduce air emissions at the refinery, are expected to be primarily capital in nature.

Desulphurization Projects - R&M estimates it will spend a total of Cdn$360 million (approximately US$300 million) to meet requirements of fuels desulphurization legislation and to enable the refinery to process up to 15,000 bpd of Oil Sands sour crude oil, while also increasing the refinery's ability to process a broader slate of bitumen based crude oil. The fuel desulphurization legislation requires lower diesel sulphur levels (15 ppm) by June 2006 and lower gasoline sulphur levels (30 ppm average, 80 ppm cap) by 2009. The environmental permit application for all these proposed changes has been approved. Construction for the diesel desulphurization facilities commenced in 2004 and is planned to be completed in early 2006, including a new desulphurization unit, a new hydrogen plant, a new tail gas treating unit for the existing sulphur recovery plants, as well as modifications to other existing units.

We are currently assessing plans for potential additional refinery modifications after 2006 in order to have the potential to integrate up to an additional 30,000 bpd of Oil Sands crude oil. Cost estimates for this project are not yet available.

Other

Financing Activities

In 2000, we entered into a financing arrangement with a third party whereby we sold an undivided interest in our Oil Sands energy service assets for $101 million and leased the assets back from the third party. We repurchased the assets in December 2004, with financing from existing revolving credit facilities.

In January 2002, we issued US$500 million principal amount of 7.15% unsecured Notes due February 1, 2032, to investors in the United States (the "US") under our US$1 billion shelf prospectus.

In December 2003 we issued US$500 million of 5.95% unsecured Notes under the remaining capacity of the US$1 billion shelf prospectus. We have now utilized the complete capacity that was available under this shelf. The net proceeds of the debt offering, together with borrowings under our available credit and term loan facilities were used to repay our 7.4% Debentures maturing February 2004 ($125 million) and

to redeem our 9.05% and 9.125% Preferred Securities in March 2004 for total cash consideration of $493 million.

In 2004 we renewed our available credit facilities of approximately $1.7 billion. Our undrawn lines of credit at December 31, 2004 were approximately $1.5 billion. Our current long-term debt ratings are, A (low) by Dominion Bond Rating Service, A3 by Moody's Investors Service and A- by Standard & Poor's. All debt ratings have a stable outlook.

In June 2004, we repurchased approximately 2.1 million barrels of crude oil originally sold to a Variable Interest Entity ("VIE") in 1999, for net consideration of $49 million. As the company economically hedged the repurchase of the inventory, the net consideration paid was equal to the original proceeds we received in 1999, when the inventory was sold to the VIE.

During the second quarter of 2004, we received $40 million from the sale of certain proprietary technology.

Other Highlights

In September 2004, we, along with our joint venture partners, a subsidiary of Enbridge Inc. and EHN Wind Power Canada, Inc. officially opened the 30-megawatt Magrath Wind Power Project ("Magrath") in southern Alberta. Magrath's zero-emissions electricity production is expected to offset the equivalent of approximately 82,000 tonnes of carbon dioxide per year. The project has benefited from the support of the Federal Government's Wind Power Production Incentive

For further information on developments and issues referred to above and other highlights of 2004, and a discussion of other trends known to us that could reasonably be expected to have a material effect on the company, 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 (OS)

We produce a variety of refinery feedstock and diesel fuel by developing the Athabasca oil sands in northeastern Alberta and upgrading the bitumen extracted at our plant near Fort McMurray, Alberta. Our Oil Sands operations, accounting for virtually all of our conventional and

synthetic crude oil production in 2003 and 2004, represent a significant portion of our 2004 capital employed (78%)[4], cash flow from operations[4] (76%) and net earnings (81%). These percentages have been determined excluding the corporate and eliminations segment information.

Operations

Our integrated Oil Sands business involves four operations. First, bitumen is supplied from a combination of a mining operation using trucks and shovels, and third party bitumen supply. Commencing in 2004, the Firebag in-situ operation began producing bitumen which was primarily sold into the market as diluted bitumen. We expect that bitumen from Firebag will be upgraded beginning in 2005, with only excess production sold into the market. Second, extraction facilities recover the bitumen from the oil sands ore that is mined. Third, heavy oil upgrading process converts bitumen into crude oil products. Fourth, our energy service needs are met through Oil Sands facilities (operated by TransAlta), that provide steam and electricity to the operations along with energy from TransAlta's proprietary natural gas fired co-generation plant that commenced operations in 2001. We use all of the steam and a portion of the power from the TransAlta co-generation facility. Our energy services facilities primarily use petroleum coke, a by-product of the upgrading process, as fuel. They also consume natural gas.

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 extraction plants on the east and west sides 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 2004, approximately 8,400 bpd of bitumen were sold, representing approximately four percent of Oil Sands' 2004 sales. In 2003, bitumen sales of 6,400 bpd represented approximately three percent of Oil Sands' sales.

After the diluted bitumen is transferred 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, delineation of the resources and 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. Natural gas is used or consumed in the production of synthetic crude oil, particularly under the steam assisted gravity drainage (SAGD) method of bitumen production from our Firebag operations, and accordingly natural gas prices are a key variable component of synthetic crude oil production costs. 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.

(4) Refer to "Non GAAP Financial Measures" on page ix of this AIF.

Principal Products

Sales of light sweet crude oil represented 55% of Oil Sands' consolidated operating revenues in 2004, compared to 56% in 2003. Sales of other products including light sour crude, diesel and bitumen represented the remaining 45% of revenues in 2004 compared to 44% in 2003. Set forth below is information on daily sales volumes and the corresponding percentage of Oil Sands consolidated operating revenues by product for each of the last two years.

	2004		2003	
Product:	(thousands of barrels per day)	(% of Oil Sands consolidated revenues)	(thousands of barrels per day)	(% of Oil Sands consolidated revenues)
Light sweet crude oil	114.9	55	112.3	56
Other products (diesel, light sour crude oil and bitumen)	111.4	45	106.0	44
Total	226.3	100	218.3	100

Transportation

Our Oil Sands business unit has 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, our initial pipeline capacity for the transport of synthetic crude oil and diluted bitumen from Fort McMurray, Alberta, to Hardisty Alberta was 60,000 bpd in 1999, increasing to 170,000 bpd in 2005. This pipeline, together with our proprietary pipeline, is expected to meet our anticipated crude oil shipping requirements for expected future production levels up to 2008. We, along with other industry shippers, are assessing Athabasca region pipeline options beyond 2008.

The company markets its crude oil product blends for sale and distribution to customers in Canada, the United States and periodically, to offshore markets.

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

We also transport natural gas to our Oil Sands operations on the company-owned and operated Albersun pipeline, constructed in 1968. It extends approximately 300 kilometres south of the plant and connects with the TransCanada Pipeline's Alberta intra-provincial pipeline system. The Albersun pipeline has the capacity to move in excess of 100 mmcf/day of natural gas. We arrange for natural gas supply and control most of

the natural gas on the system under delivery based contracts. The pipeline moves natural gas both north and south for us and other shippers. In 2004, throughput on the Albersun pipeline was approximately 46 mmcf/day.

Our 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 during the winter season and in some situations can result in higher costs.

Sales of Synthetic Crude Oil and Diesel

Aside from on site fuel use, all of Oil Sands' production is sold to, and subsequently marketed by, Suncor Energy Marketing Inc.

In 1997, we entered into a long-term agreement with Koch Industries Inc. ("Koch") to supply Koch with up to 30,000 bpd (approximately 13% of our average 2004 total production) of sour crude from the Oil Sands operation. We began shipping the crude to Koch's terminal at Hardisty, Alberta (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 by either party. Neither party has provided notice at this time.

In 2000, we announced a long term sales agreement with Consumers' Co-operative Refineries Limited ("CCRL") under which we expected to begin supplying CCRL with 20,000 bpd of sour crude oil production from our Project Millennium expansion facilities by late 2002. After certain construction delays, CCRL began accepting delivery of sour crude in the first quarter of 2003. Prices for sour crude oil under these agreements are set at agreed differentials to market benchmarks.

In 2001, we 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. The diluent supply agreement is expected to end when the bitumen processing and sour crude oil supply agreement, described below, takes effect.

The processing agreement between the company and Petro-Canada is expected to take effect in 2008. Under the agreement, we will process at least 27,000 bpd of Petro-Canada bitumen on a fee for service basis. Petro-Canada will retain ownership to the bitumen and resulting sour crude oil production of about 22,000 bpd. In addition, we will sell an additional 26,000 bpd of our proprietary sour crude oil production to Petro-Canada. Both the processing and sales components of the agreement will be for a minimum 10-year term.

There were no customers that represented 10% or more of our consolidated revenues in 2004 or 2003. There was one customer in 2002 that represented 10% or more of our consolidated revenues.

A portion of our Oil Sands production is used in connection with our Sarnia refining operations. During 2004, the Sarnia refinery processed approximately 8% (2003 -10%) of Oil Sands crude oil production.

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 "Asset Retirement Obligations" under "Critical Accounting Estimates" in the "Suncor Overview and Strategic Priorities" section of our MD&A.

NATURAL GAS (NG)

Our 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's production provides a price hedge for natural gas purchased for consumption at our Oil Sands facility and our refineries in Sarnia, Ontario and near Denver, Colorado. In addition, our U.S. subsidiary, Suncor Energy (Natural Gas) America Inc., is acquiring land and exploring for coal bed methane and conventional natural gas in the United States.

In 2004, natural gas and natural gas liquids accounted for approximately 97% 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. We drill primarily medium to high-risk wells focusing on prospects that can be connected to existing infrastructure. In addition, our U.S. affiliate, Suncor Energy (Natural Gas) America Inc. is exploring for natural gas in western Montana and for coal bed methane in several of the U.S. states.

Marketing, Pipeline and Other Operations

We operate 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. Our capacity interest in these gas processing plants is approximately 103 mmcf/day. We also have varying undivided percentage interests in natural gas processing plants operated by other companies and processing agreements in facilities where we do not hold an ownership interest.

Approximately 78% of our 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, we are responsible for transportation arrangements to the point of sale. Some of the direct sales arrangements include some of the natural gas consumed in our Oil Sands plant at Fort McMurray and in our Sarnia refining operations.

Approximately 22% of our 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 our system sales volumes are contracted to Cargill Gas Marketing Ltd. (formerly TransCanada Gas Services) and Pan-Alberta Gas. These companies resell this natural gas primarily to eastern Canadian and Midwest and eastern United States markets.

To provide exposure to the Pacific North West and California markets, we have a long-term gas pipeline transportation contract on the National Energy Group Transmission Pipeline (formerly Pacific Gas Transmission).

Our conventional crude oil production is generally sold under spot contracts or under contracts that can be terminated on relatively short notice. Our 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.

Principal Products

Consistent with 2003, sales of natural gas represented 90% of NG's consolidated operating revenues in 2004, with the remaining 10% comprised of sales of natural gas liquids and crude oil. Set forth below is information on daily sales volumes and the corresponding percentage of Natural Gas' consolidated operating revenues by product for the last two years.

	2004		2003	
Product:	(thousands of barrels of oil equivalent per day)	(% of NG consolidated revenues)	(thousands of barrels of oil equivalent per day)	(% of NG consolidated revenues)
Natural gas	33.3	90	31.2	90
Natural gas liquids	2.5	7	2.3	6
Crude Oil	1.0	3	1.4	4
Total	36.8	100	34.9	100

Competitive Conditions

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

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 "Asset Retirement Obligations" under "Critical Accounting Estimates" in the "Suncor Overview and Strategic Priorities" section of our MD&A.

ENERGY MARKETING & REFINING – CANADA (EM&R)

Our EM&R business unit operates a refining and marketing business in Central Canada, and an energy marketing and trading business. Our refinery in Sarnia, Ontario, refines petroleum feedstock from Oil Sands and other sources into gasoline, distillates, and petrochemicals with the majority of these refined products being distributed in our primary market of Ontario. For information about EM&R's energy marketing and trading business, refer to "Energy Marketing and Refining – Canada (EM&R) Three-Year Highlights", under the "Energy Marketing & Trading" heading.

Approximately 58% of EM&R's petroleum products sales in 2004 (2003 – 58%) were sold through a distribution network in Ontario that sells gasoline and diesel fuel to retail customers. Approximately 37% (2003 – 37%) was sold to industrial, commercial, wholesale and refining customers in Ontario and Quebec, representing primarily jet fuels, diesel and gasoline. The remaining 5% (2003 - 5%) 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.

EM&R's external financial reporting structure changed in 2004 so that its Rack Back and Rack Forward divisions (described as follows) are now reported on a consolidated basis. 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 and the SPC joint venture. The Rack-Forward division is comprised of retail operations, 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 EM&R and The Pioneer Group Inc.

EM&R results also include the impact of Suncor's energy marketing and energy trading activities, which is comprised of both third party crude oil

marketing and financial and physical derivatives trading activities.

Procurement of Feedstocks

The Sarnia refinery uses both synthetic and conventional crude oil. In 2004, the Sarnia refinery procured approximately 41% (2003 – 53%) of its synthetic crude oil feedstock from our Oil Sands production. In 2004, 66% (2003 – 64%) 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. As a result of the fire at Oil Sands, during 2005, EM&R may be required to purchase additional synthetic crude oil feedstock to meet customer demand, resulting in higher purchased product costs.

We procure conventional crude oil feedstock for our Sarnia 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. We have 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 which can be terminated on short notice.

In 1998, EM&R signed a 10-year feedstock agreement with a Sarnia-based petrochemical refinery, Nova Chemicals (Canada) Ltd. Under this buy/sell agreement, we obtain feedstock that is more suitable for production of transportation fuels in exchange for feedstock more suitable for petrochemical cracking. We also enter into reciprocal buy/sell or exchange arrangements with other refining companies from time to time as a means of minimizing transportation costs, balancing product availability and enhancing refinery utilization. We also purchase 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 bpd of crude oil. Sarnia refinery sales in 2004 averaged approximately 94,300 bpd (2003 – 92,100 bpd). The 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 has the flexibility to vary the gasoline/distillate ratio. The hydrocracker has capacity to process approximately 23,300 bpd. Additional flexibility in gasoline, octane and petrochemical production is provided by the complementary operations of an alkylation unit with a capacity of 5,400 bpd. The alkylation unit produces a high octane gasoline blending component. The petrochemical facilities have a charge capacity of 13,100 bpd and produce benzene, toluene, mixed xylenes, orthoxylene and raffinate. The aromatic solvents unit produces about 1,000 bpd of A-100 and A-150. A gasoline desulphurization unit that came into service in the fourth quarter of 2003 has a capacity to process 10,250 bpd of gasoline components.

The refinery has a cracking capacity of 40,200 bpd 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 2004, a sustainability study to assess the catcracker concluded that, with planned 2005 improvements and upgrades, it can continue to be operated economically and safely for up to 10 years. A second phase of the study, planned to be completed in 2005, will assess configuration and investment options for replacing the catcracker within 10 years.

During the second quarter of 2004, EM&R completed scheduled and unscheduled maintenance shutdowns on various units within one of the refinery's plants. As a result, the refinery operated with

lower than capacity utilization rates during the second quarter of 2004.

Overall, crude utilization averaged 100% for the year, up 5% from 2003. 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	2004	2003
Average daily crude input (barrels per day)	69,900	66,300
Average crude utilization rate (%)(1)	100	95
Average cracking capacity utilization (%)(2)	91	87

Notes:

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

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

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

Principal Products

Sales of gasoline and other transportation fuels represented 72% of EM&R's consolidated operating revenues in 2004, unchanged from 2003. 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.

	2004		2003	
Product:	(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	4.6	29	4.4	29
Joint Ventures	3.1	16	3.1	16
Other	1.0	9	1.1	10
Jet Fuel	0.9	4	0.7	3
Diesel	3.1	14	3.0	14
Sub-total – Transportation Fuels	12.7	72	12.3	72
Petrochemicals	0.8	6	0.8	5
Heating Fuels	0.4	3	0.5	4
Heavy Fuel Oils	0.7	1	0.8	2
Other	0.8	3	0.6	2
Total Refined Products	15.4	85	15.0	85
Other Non-Refined Products(1)		3		6
Energy Marketing & Trading		12		9
Total %		100		100

Note:

(1) Includes ancillary revenues

Principal Markets

Approximately 58% (2003 – 58%) of EM&R's total sales volumes are marketed through retail networks, including the Sunoco-branded retail network, joint-venture operated retail stations and cardlock operations. In 2004, this network was comprised of:

278 (2003 – 279) Sunoco-branded retail service stations
147 (2003 – 147) Pioneer-operated retail service stations
52 (2003 – 53) UPI-operated service stations and a network of 14 bulk distribution facilities for rural and farm fuels
23 (2003 – 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 our premium high octane gasoline, and "Gold Diesel" used in respect of our premium low sulphur diesel product.

Approximately 37% (2003 – 37%) 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 other petrochemicals, primarily in Canada and the U.S., through SPC. EM&R has a 50% interest in SPC, a petrochemical marketing joint venture that markets products from our Sarnia Refinery and from a Toledo, Ohio, refinery owned by the joint venture partner. SPC 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 19% in 2004 (2003 – 19%). Transportation fuels accounted for 82% of EM&R's total sales volumes in 2004 (2003 – 82%); and petrochemicals accounted for 5% (2003 – 5%). 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. We have a separate supply agreement with each of UPI and Pioneer. These supply agreements are evergreen, subject to termination only in accordance with the terms of the various agreements between the parties.

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 us and 45% owned by another refiner. The pipeline operates as a private facility for its owners, serving terminal facilities in

Toronto, Hamilton and London, with a capacity of 126,000 bpd (20,000 cubic metres). EM&R utilized 55% of this capacity in 2004. Total utilization of the pipeline was 88% in 2004.

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.

We believe our own storage facilities, and those under long-term contractual arrangements with other parties, are sufficient to meet our current and foreseeable storage needs.

Competitive Conditions

Competitive conditions affecting our EM&R business are described under “Competition” 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, refer to the sections entitled “Outlook” and “Risk/Success Factors Affecting Performance” in the EM&R section of our 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 “Asset Retirement Obligations” under “Critical Accounting Estimates” in the “Suncor Overview and Strategic Priorities” section of our MD&A.

REFINING & MARKETING – U.S.A. (R & M)

Our R&M business unit, which was acquired August 1, 2003, operates a pipeline transportation, refining and marketing business primarily in Colorado and Wyoming. The Denver area refinery, located in Commerce City, Colorado, has a crude distillation capacity of 60,000 bpd, processing a mixture of Canadian heavy, high sulphur crudes, and domestic heavy, high sulphur and low sulphur crudes. The majority of the refined products from our Denver refinery are distributed in its primary market of Colorado.

Approximately 24% of R&M’s petroleum products sales in 2004 were sold through a distribution network in Colorado that sells gasoline and diesel fuel to retail customers. R&M’s retail network includes 43 Phillips 66-branded company operated sites, as well as contractual agreements with approximately 140 Phillips 66 - branded marketer outlets throughout Colorado. Approximately 60% of R&M’s petroleum product sales volumes were to industrial, commercial, wholesale and refining customers in Colorado, representing primarily jet fuels, diesel and gasoline. Asphalt sales comprise the remaining 16% of R&M’s refined product sales volumes for 2004.

Procurement of Feedstocks

The Denver refining operation uses conventional crude oil. Approximately 45% of the Denver refinery’s crude oil is purchased from Canadian sources, with the remainder supplied from sources in the United States, primarily in the Rocky Mountain region. The refinery’s crude oil purchase contracts have terms ranging from month-to-month to one year. In the event of a significant disruption in the supply of crude oil, the refinery has the flexibility to substitute other sources of sweet or sour crude oil on a spot purchase basis.

R&M has a buy/sell agreement with a third party refinery located in Cheyenne, Wyoming, whereby R&M sells residual coke from its refinery to the third party refinery and purchases coker gas oil, which is then further processed into finished products at R&M’s Denver refinery. This contract expires in July 2006.

Refining Operations

The Denver refinery has a crude distillation capacity of 60,000 bpd, processing a mixture of Canadian heavy, high sulphur crudes, and domestic heavy, high and low sulphur crudes. Upgrading units at the Denver refinery include a 19,000 bpd fluidized catalytic cracker, a 12,500 bpd distillate hydrotreater and a 14,000 bpd gas oil hydrotreater. The refined gasoline products from the Denver refinery supply R&M’s marketing operations in Colorado. Refining sales in 2004 averaged approximately 58,500 bpd (9,300 m^3 per day).

The Denver refinery is a high conversion refinery that produces a full range of products, including gasoline, jet fuels, diesel and asphalt. The refinery’s upgrading units enable it to process a crude slate containing nearly 50% heavy, high sulphur crude. Overall, crude utilization averaged 92% in 2004. The following chart sets out daily crude input, average refinery utilization rates and cracking capacity utilization for 2004 and the five month period in 2003 since acquisition.

Denver Refinery Capacity	January 1, 2004 to December 31, 2004	August 1, 2003 to December 31, 2003
Average daily crude input (barrels per day)	55,400	58,800
Average crude utilization rate (%)(1)	92	98
Average fluidized catalytic cracker capacity utilization rate (%)(2)	88	95

Notes:

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

(2) Based on cracking capacity and input to other units or sales made to customers.

Principal Products

Sales of gasoline and other transportation fuels represented 85% of R&M's consolidated operating revenues in 2004. Set forth below is information on daily sales volumes and percentage of R&M's consolidated operating revenues contributed by product group for 2004 and the five-month period post acquisition in 2003.

	January 1, 2004 to December 31, 2004		August 1, 2003 to December 31, 2003	
Product:	(Thousands of cubic meters per day)	(% of R&M's consolidated revenues)	(Thousands of cubic meters per day)	(% of R&M's consolidated revenues)
Transportation Fuels				
Gasoline				
Retail	0.7	8	0.7	13
Other	3.8	44	3.5	40
Jet Fuel	0.5	7	0.5	6
Diesel	2.2	26	2.3	26
Total Transportation Fuels	7.2	85	7.0	85
Asphalt	1.5	8	1.7	10
Other	0.6	3	0.4	2
Total Refined Product Sales	9.3	96	9.1	97
Other Non-Refined Product(1)		4		3
		100		100

Note:

(1) Ancillary revenues include non-fuel retail sales.

Principal Markets

Approximately 24% of R&M's total sales volumes are marketed through Phillips 66 - branded retail outlets. This network is comprised of:

- 43 owned Phillips 66 - branded retail sites, which account for approximately 7% of R&M's sales volumes.
- Supply agreements with approximately 140 Phillips-66 branded marketer outlets throughout the state of Colorado, which account for approximately 17% of R&M's sales volumes. These agreements are typically for three year terms with provision for automatic three year renewal periods on an evergreen basis.

We have an exclusive license from ConocoPhillips to use the Phillips-66 and related trademarks and brand names in Colorado until December 31, 2012.

The Denver refinery also supplies all of its asphalt production to KC Asphalt, a joint venture between ConocoPhillips and Koch Industries, Inc. Asphalt sales made up about 16% of R&M's total 2004 sales volumes.

Approximately 60% of R&M's total sales volumes are sold to industrial, commercial, wholesale, and refining customers, primarily in Colorado, of which approximately 40% was sold under a long-term supply agreement with ConocoPhillips in 2004. Under this agreement, R&M supplies ConocoPhillips with gasoline and distillates. Under the terms of the agreement, the supplied volumes are to decrease over time until approximately half of the current volumes will be supplied in the 10th year of the agreement.

R&M estimates its sales of total light fuels refined product in 2004 represented a market share, in its primary market of Colorado, of approximately 23%. Within this market, R&M's Phillips 66 - branded sites represent a 13% market share.

Transportation and Distribution

Almost all crude oil processed at the Denver refinery is transported via pipeline. R&M owns and operates the Rocky Mountain Crude system which runs from Guernsey, Wyoming to Denver, Colorado. This pipeline is a common carrier pipeline that transports crude for the Denver refinery as well as for other shippers. We also operate a joint venture crude pipeline, the Centennial pipeline, from Guernsey, Wyoming to Cheyenne, Wyoming. We own approximately 65% of this joint venture pipeline, with, the other 35% owned by another area refiner. In 2004, the Rocky Mountain Crude system utilized more than 100% of capacity due the use of a drag reducing agent, with average throughput of 34,200 bpd in the Guernsey to Cheyenne leg of the pipeline, and 65,200 bpd in the higher capacity Cheyenne to Denver leg. During the same period, the joint venture pipeline utilized approximately 97% of capacity, with an average throughput of approximately 59,100 bpd.

R&M has its own 30,000 bpd capacity truck-loading terminal at the Denver area refinery where customers can pick up product, a one mile long 7,000 bpd jet fuel pipeline that connects to a common carrier pipeline system for deliveries to the Denver International Airport, and a four mile long

14,000 bpd diesel pipeline that delivers diesel product directly to the Union Pacific railroad yard in Denver, Colorado.

We believe our own storage facilities, and those under long-term contractual arrangements with other parties, are sufficient to meet our current and foreseeable storage needs.

Competitive Conditions

Competitive conditions affecting our Refining & Marketing – U.S.A. business are described under the heading "Competition" in the "Risk/Success Factors" section of this Annual Information Form.

Environmental Compliance

Due to increasingly stringent regulations regarding water discharges, the Denver Refinery will have to add additional water treating equipment for the discharge of process waste water. It is estimated that this will cost approximately $3 million and be completed in the 2006 to 2008 timeframe. For a description of other impacts of environmental protection requirements on Refining & Marketing – U.S.A., refer to the R&M section of "Three Year History" of this Annual Information Form, and the sections entitled "Outlook" and "Risk/Success Factors Affecting Performance" in the Refining & Marketing – U.S.A. section of our MD&A. Also refer to "Environmental Regulation and Risk" and "Governmental Regulation" in the "Risk/Success Factors" section of this Annual Information Form, and "Asset Retirement Obligations" under "Critical Accounting Estimates" in the "Suncor Overview and Strategic Priorities" section of our MD&A.

MATERIAL CONTRACTS

During the year ended December 31, 2004 we have not entered into any contracts, nor are there any contracts still in effect, that are material to our business, other than contracts entered into in the ordinary course of business and the Shareholder Rights Plan dated April 28, 2002.

RESERVES ESTIMATES

We are a Canadian issuer and are subject to Canadian reporting requirements, including rules in connection with the reporting of our reserves. However, we have received an exemption from Canadian securities administrators permitting us to report our reserves in accordance with U.S. disclosure requirements. Pursuant to U.S. disclosure requirements, we disclose net proved conventional oil and gas reserves, including natural gas reserves and bitumen reserves from our Firebag in-situ leases, using constant dollar cost and pricing assumptions. As there is no recognized posted bitumen price, these assumptions are based on a posted benchmark oil price, adjusted for transportation, gravity and other factors that create the difference ("differential") in price between the posted benchmark price and Suncor's bitumen. Both the posted benchmark price and the differential are generally determined as of a point in time, namely December 31 ("Constant Cost and Pricing"). Our reserves from our Firebag in-situ leases are reported as barrels of bitumen, using these Constant Cost and Pricing assumptions (see "REQUIRED U.S. OIL AND GAS AND MINING DISCLOSURE – Proved Conventional Oil and Gas Reserves" for net proved conventional oil and gas reserves).

Pursuant to U.S. disclosure requirements, we also disclose gross proved and probable mining reserves. The estimate of our mining reserves is based in part on the current mine plan and estimates of extraction recovery and upgrading yields, rather than an analysis based on constant dollar or forecast pricing and cost assumptions. In accordance with these rules, we report mining reserves as barrels of synthetic crude oil based on a net coker, or synthetic crude oil yield from bitumen of 80 to 81%. We do not disclose our mining reserves on a net basis as we are continuing to discuss the terms of our option to transition to the Province of Alberta's generic bitumen based royalty regime in 2009 and accordingly, the net mining reserves calculation cannot be estimated (see "REQUIRED U.S. OIL AND GAS AND MINING DISCLOSURE – Proved and Probable Oil Sands Mining Reserves" for gross proved and probable mining reserves). Our Firebag in-situ leases are already subject to royalty based on bitumen, rather than synthetic crude oil. (For a full discussion of our oil sands crown royalties, see the "Oil Sands Crown Royalties and Cash Income Taxes" in the "Suncor Overview and Strategic Priorities" section of our MD&A.)

In addition to required disclosure, our exemption issued by Canadian securities administrators permits us to provide further disclosure voluntarily. We provide this additional voluntary disclosure to show aggregate proved and probable oil sands reserves, including both mining reserves and reserves from our Firebag in-situ leases. In our voluntary disclosure we report our aggregate reserves on the following basis:

(a) Gross proved and probable mining reserves, on the same basis as disclosed pursuant to U.S.

disclosure requirements (reported as barrels of synthetic crude oil based upon a net coker, or synthetic crude oil yield from bitumen of 80% to 81%); and

(b) Gross proved and probable bitumen reserves from Firebag in-situ leases, evaluated based on normalized constant dollar cost and pricing assumptions. These assumptions use a posted benchmark oil price as of December 31, but apply a differential generally intended to represent a normalized annual average for the year ("Annual Average Differential Pricing"), rather than a point in time differential, in accordance with Canadian Securities Administrators Staff Notice 51-315 ("CSA Staff Notice 51-315"). Bitumen reserves estimated on this basis are subsequently converted, for comparison purposes only, to barrels of synthetic crude oil based on a net coker or synthetic crude oil yield from bitumen of 82%.

Accordingly, our voluntary disclosures of proved and probable reserves from our Firebag in-situ leases will differ from our required U.S. disclosure in three ways. Reserves from our Firebag in-situ leases are:

(a) disclosed on a gross basis versus a net basis under U.S. disclosure requirements;

(b) converted from barrels of bitumen under U.S. disclosure requirements to barrels of synthetic crude oil for comparability purposes only; and

(c) evaluated based on Annual Average Differential Pricing assumptions, in accordance with CSA Staff Notice 51-315, versus Constant Cost and Pricing assumptions pursuant to U.S. disclosure requirements.

Under the U.S. disclosure requirements described above, we announced on January 21, 2005 that we debooked our proved reserves from our Firebag in-situ leases. December 31, 2004 point-in-time posted benchmark oil prices were unusually low and December 31, 2004 point-in-time diluent prices, which form part of the differential calculation, were unusually high. This combination resulted in a determination that our proved Firebag in-situ reserves were uneconomic as at December 31, 2004 (see "REQUIRED U.S. OIL AND GAS AND MINING DISCLOSURE - - Proved Conventional Oil and Gas Reserves").

Under our voluntary disclosure, using 2004 Annual Average Differential Pricing, our proved Firebag in-situ reserves were determined to be economic and accordingly, are disclosed under "VOLUNTARY OIL SANDS RESERVES DISCLOSURE - Estimated Gross Proved and Probable Oil Sands Reserves Reconciliation". Comparisons of these two reserve estimates will show material differences based primarily on the pricing assumptions used, but will also show differences based on whether the reserves are reported as barrels of bitumen or barrels of synthetic crude oil, and whether the reserves are reported on a gross or net basis.

All of our reserves have been evaluated as at December 31, 2004 by independent petroleum consultants, Gilbert Laustsen Jung Associates Ltd. ("GLJ"). In reports dated February 9, 2005, and February 17, 2005 ("GLJ Oil Sands Reports"), GLJ evaluated our proved and probable reserves on our oil sands mining leases and Firebag in-situ leases respectively, pursuant to both U.S. disclosure requirements using Constant Cost and Pricing assumptions, and pursuant to CSA Staff Notice 51-315, using 2004 Annual Average Differential Pricing assumptions.

Estimates in the GLJ Oil Sands Reports consider recovery from leases for which regulatory approvals have been granted. The mining reserve estimates are based on a detailed geological assessment and also consider industry practice, drill density, production capacity, extraction recoveries, upgrading yields, mine plans, operating life, and regulatory constraints.

For Firebag in-situ reserve estimates, GLJ considered similar factors such as our regulatory approval, project implementation commitments, detailed design estimates, detailed reservoir studies, demonstrated commercial success of analogous commercial projects, and drill density. Our proved and probable reserves are contained within the AEUB approval area. Our proved reserves are delineated with 40 to 80 acre spacing plus 3D seismic control while our probable reserves are delineated with 80 to 160 acre

spacing plus 3D seismic control. The major facility expenditures to develop our proved undeveloped reserves have been approved by our Board. Plans to develop our probable undeveloped reserves in subsequent phases are under way but we have not yet received final approval from our Board.

In a report dated February 17, 2005 ("GLJ NG Report"), GLJ also evaluated our proved reserves of natural gas, natural gas liquids and crude oil (other than reserves from our mining leases and the Firebag in-situ reserves) as at December 31, 2004.

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

REQUIRED U.S. OIL AND GAS AND MINING DISCLOSURE

Proved and Probable Oil Sands Mining Reserves

	Gross Oil Sands Mining Leases(2)		
(millions of barrels of synthetic crude oil)(1)	Proved	Probable	Proved & Probable
December 31, 2003	878	952	1,830
Revisions of previous estimates	140	(105)	35
Extensions and discoveries	—	—	—
Production	(79)	—	(79)
December 31, 2004	939	847	1,786

Notes:

(1) Synthetic crude oil reserves are based on a net coker, or synthetic crude oil yield from bitumen of 80 to 81%.

(2) Our gross mining reserves are based in part on our current mine plan and estimates of extraction recovery and upgrading yields, rather than an analysis based on constant dollar or forecast pricing and cost assumptions.

(3) We do not disclose our mining reserves on a net, after royalty basis as we continue to discuss the terms of our option to transition to the Province of Alberta's generic bitumen based royalty regime in 2009 and accordingly, the net mining reserves calculation cannot be estimated (see "Oil Sands Crown Royalties and Cash Income Taxes" in the "Suncor Overview and Strategic Priorities" section of our MD&A for a discussion of our royalty regime).

Oil Sands Mining Operating Statistics

The following table sets out certain operating statistics for the Oil Sands mining operations. Statistics for the Oil Sands Firebag in-situ operations are not included but are addressed under the heading "Proved Conventional Oil and Gas Reserves" and "Sales, Production, Well Data, Land Holdings and Drilling - Conventional".

	2004	2003	2002
Total mined volume (1) millions of tones	371.2	316.9	291.0
Mined volume to tar sands ratio(1)	41.6%	48.1%	50.6%
Tar sands mined millions of tones	154.3	152.5	147.3
Average bitumen grade (weight %)	11.2%	11.3%	11.2%
Crude bitumen in mined tar sands millions of tones	17.3	17.2	16.6
Average extraction recovery %	91.9%	92.0%	91.3%
Crude bitumen production millions of cubic meters(2)	15.7	15.7	15.0
Average upgrading yield % (net)	79.1%	79.4%	79.1%
Gross synthetic crude oil produced Thousands of barrels per day(3)	215.6	216.6	205.8

Notes:

(1) Includes pre-stripping of mine areas and reclamation volumes.

(2) Crude bitumen production is equal to crude bitumen in mined tar sands multiplied by the average extraction recovery and the appropriate conversion factor.

(3) Cubic meters are converted to barrels at the conversion factor of 6.29.

Proved Conventional Oil and Gas Reserves

The following data is provided on a net basis 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 our Oil Sands mining activities are excluded, while in-situ Firebag reserves are included.

NET PROVED RESERVES(2)

Crude Oil, Natural Gas Liquids and Natural Gas

Constant costs and pricing as at December 31,	Oil Sands business: Firebag – Crude Oil (millions of barrels of bitumen) (1),(3),(4)	Natural Gas business: Crude Oil and Natural Gas Liquids (millions of barrels) (5)	Total (millions of barrels)	Natural Gas business: Natural Gas (billions of cubic feet) (5)
December 31, 2001	—	10	10	545
Revisions of previous estimates	—	—	—	(18)
Purchases of minerals in place	—	—	—	—
Extensions and discoveries	151	1	152	39
Production	—	(1)	(1)	(48)
Sales of minerals in place	—	—	—	(2)
December 31, 2002	151	10	161	516
Revisions of previous estimates	273	(2)	271	(50)
Purchases of minerals in place	—	—	—	—
Extensions and discoveries	—	1	1	40
Production	—	(1)	(1)	(50)
Sales of minerals in place	—	—	—	—
December 31, 2003	424	8	432	456
Revisions of previous estimates	(420)(3)	1	(419)	(23)
Purchases of minerals in place	—	—	—	14
Extensions and discoveries	—	—	—	53
Production	(4)	(1)	(5)	(54)
Sales of minerals in place	—	—	—	—
December 31, 2004	—	8	8	446
Proved Developed				
December 31, 2001	—	8	8	416
December 31, 2002	—	8	8	426
December 31, 2003	92	6	98	403
December 31, 2004	—	7	7	385

Notes:

(1) Oil Sands business - Firebag net reserves means Suncor's undivided percentage interest in total reserves after deducting Crown royalties, freehold and overriding royalty interests. The calculation of these third party interests is uncertain and based on assumptions about future prices, production levels, operating costs and capital expenditures.

(2) Although Suncor is subject to Canadian disclosure rules in connection with the reporting of its reserves, we have received exemptive relief from Canadian securities administrators permitting us to report our proved reserves in accordance with U.S. disclosure practices. See Reliance on Exemptive Relief on pg 44.

(3) Estimates of proved reserves from our Firebag in-situ leases are based on Constant Cost and Pricing assumptions as at December 31. In 2004, due to unusually low year-end posted benchmark oil prices, and unusually high year-end diluent prices, our proved reserves were determined to be uneconomic as at this year end point in time.

(4) We have the option of selling the bitumen production from these leases and/or upgrading the bitumen to synthetic crude oil.

(5) Natural Gas business net reserves means Suncor's undivided percentage interest in total reserves after deducting the interest of third parties, including Crown royalties, freehold and overriding royalties, calculated following generally accepted guidelines, on the basis of prices and the royalty structure in effect at year end and anticipated production rates. The calculation of these third party interests is uncertain and based on assumptions about future natural gas prices, production levels, operating costs and capital expenditures. Royalties can vary, depending upon selling 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, 2004, other than the

potential effect of higher bitumen pricing subsequent to December 31, 2004, which may result in the re-booking of proved Firebag in-situ reserves. We do not have long-term supply agreements or contracts with governments or authorities in which we act as producer nor do we have any interest in oil and gas operations accounted for by the equity method.

Capitalized Costs Relating to Oil and Gas Activities (1)

($ millions)	For the years ended December 31, 2004	2003
Proved properties	1,395	1,904
Unproved properties	1,399	293
Other support facilities and equipment	18	18
Total cost	2,812	2,215
Accumulated depreciation and depletion	(695)	(590)
Net capitalized costs	2,117	1,625

Note:

(1) In 2004, capitalized costs do not include costs related to the associated upgrading expansion projects. Prior year amounts have been reclassified to conform to this presentation.

Costs Incurred in Oil and Gas Acquisition, Exploration and Developmental Activities (1)

($ millions)	For the years ended December 31, 2004	2003	2002
Property acquisition costs			
Proved properties	32	—	2
Unproved properties	10	29	12
Exploration costs	78	46	17
Development costs	545	489	441
Asset retirement obligations	4	5	—
Total capital and exploration expenditures	669	569	472

Note:

(1) In 2004, costs incurred do not include costs related to associated upgrading expansion projects. Prior year amounts have been reclassified to conform to this presentation.

Results of Operations for Oil and Gas Production

($ millions)	For the years ended December 31, 2004	2003	2002
Revenues			
Sales to unaffiliated customers	469	319	200
Transfers to other operations	64	61	16
	533	380	216
Expenses			
Production costs	122	44	39
Depreciation, depletion and amortization	130	76	66
Exploration	57	86	27
Gain on disposal of assets	(19)	(12)	(4)
Other related costs	73	37	10
	363	231	138
Operating profit before income taxes	170	149	78
Related income taxes	(48)	(40)	(43)
Results of operations	122	109	35

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. We caution against viewing this information as a forecast of future economic conditions or revenues, and do not consider it to represent the fair market value of our Firebag in-situ and Natural Gas properties. Figures are based on our actual year-end commodity prices. Readers are cautioned that commodity prices are volatile. To illustrate this volatility, the following table sets out certain commodity benchmark prices over the past three years:

	2004	2003	2002
Year end natural gas price (AECO- CDN$/GJ)	7.17	5.28	5.21
Year end crude oil price (WTI US$/bbl)	43.26	32.50	29.40
Year end light/heavy crude oil differential, WTI at Cushing less LLB at Hardisty (US$/bbl)	22.71	10.34	7.60

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 and royalties 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. 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, we have 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 estimated cash flows related to asset retirement obligations. Deducting future income tax expenses then further reduces the estimated pre-tax

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 pre-tax cash flows relating to our proved oil and gas reserves less the tax basis of the properties involved. Royalties are determined based upon the appropriate royalty rates and regimes in effect at year end for Firebag and natural gas production, and in the case of Firebag, assumes that Firebag is classified as a separate operation for royalty purposes, as described in our MD&A., (See “Oil Sands Crown Royalties and Cash Income Taxes” in the “Suncor Overview and Strategic Priorities” Section of our MD&A). 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”.

($ millions)	2004	2003	2002
Future cash flows	3,355	11,655	8,964
Future production and development costs	(704)	(5,141)	(3,007)
Other related future costs	(367)	(391)	(314)
Future income tax expenses	(460)	(1,694)	(2,094)
Subtotal	1,824	4,429	3,549
*Discount at 10%	(750)	(2,578)	(1,822)
Standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves after income taxes	1,074	1,851	1,727

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

($ millions)	2004	2003	2002
Balance, beginning of year	1,851	1,727	440
Sales and transfers of oil and gas produced, net of production costs	(359)	(306)	(192)
Net changes in prices and production costs	(1,786)	(1,010)	664
Changes in estimated future development costs	14	(13)	(38)
Extensions, discoveries and improved recovery, less related costs	131	95	1,387
Development costs incurred during the period	524	329	112
Revisions of previous quantity estimates	(47)	712	(45)
Purchases of reserves in place	32		
Accretion of discount	245	260	68
Net changes in income taxes	426	272	(697)
Other related costs	43	(215)	28
Balance, end of year	1,074	1,851	1,727

Sales, Production, Well Data, Land Holdings and Drilling Activity - Conventional

The following tables set out additional information on our conventional oil and gas producing activities, including our Firebag in-situ operation. Information with respect to our Oil Sands mining operations is not covered by the information below but is addressed in the preceding information under “Oil Sands Mining Operations”.

Sales Prices(1), (2)

For the year ended December 31,	2004	2003	2002
Crude Oil and Bitumen ($/bbl) (3)	37.71	40.29	31.72
NGL ($/bbl)	42.82	36.08	29.35
Natural Gas ($/mcf)	6.70	6.42	3.91

Notes:

(1) Production is based in Western Canada.

(2) Prices are calculated using our working interest production before royalties.

(3) Prices for 2003 and 2002 do not include sales of bitumen.

Production Costs

For the year ended December 31, ($ per BOE of gross production)	2004	2003	2002
Average production (lifting) cost of conventional crude oil and gas(1)	7.08	3.48	3.15

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, and Firebag central facilities. It does not include an estimate for future asset retirement costs. As our Firebag in-situ leases were not in operation until 2004, the 2002 and 2003 production costs only include the costs associated with Suncor’s Natural Gas business. For 2004, these costs represent a blended average of our Firebag and Natural Gas lifting costs.

Producing Oil and Gas Wells

	Crude Oil(3)		Natural Gas		Total	
As at December 31, 2004 number of wells	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Alberta	60	48	321	186	381	234
British Columbia	26	12	97	44	123	56
Total	86	60	418	230	504	290

Notes:

(1) Gross wells are the total number of wells in which an interest is owned.

(2) Net wells are the sum of fractional interests owned in gross wells.

(3) Well information includes Firebag.

Oil and Gas Acreage

As at December 31, 2004	Developed		Undeveloped(1)		Total	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
(thousands of acres)						
Canada						
Natural Gas	840	380	650	450	1,490	830
Firebag	1	1	285	285	286	286
Total Canada	841	381	935	735	1,776	1,116
USA						
Natural Gas	—	—	396	243	396	243
Total	841	381	1,331	978	2,172	1,359

Notes:

(1) Undeveloped acreage is considered to be those on which wells have not been drilled or completed to a point that would permit production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves. Gross acres mean all the acres in which we have either an entire or undivided percentage interest.

(2) Net acres represent the acres remaining after deducting the undivided percentage interest of others from the gross acres.

Drilling Activity

For the year ended December 31, 2004	Net Exploratory			Net Development		
	Productive	Dry Holes	Total	Productive	Dry Holes	Total
(number of net wells)						
Canada						
Natural Gas	5	5	10	15	—	15
Firebag	—	—	—	11	—	11
Total	5	5	10	26	—	26

For the year ended December 31, 2003	Net Exploratory			Net Development		
	Productive	Dry Holes	Total	Productive	Dry Holes	Total
(number of net wells)						
Canada						
Natural Gas	3	6	9	17	4	21
Firebag	—	—	—	20	—	20
Total	3	6	9	37	4	41

For the year ended December 31, 2002	Net Exploratory			Net Development		
	Productive	Dry Holes	Total	Productive	Dry Holes	Total
(number of net wells)						
Canada						
Natural Gas	2	4	6	18	4	22
Firebag	—	—	—	—	—	—
Total	2	4	6	18	4	22

At December 31, 2004, we were participating in the drilling of 19 gross (16 net) exploratory and development wells.

Future Commitments to Sell or Deliver Crude Oil and Natural Gas

Our Natural Gas business has entered into a number of natural gas sale commitments aggregating approximately 109 mmcf/day. These sales commitments consist of both short-and long-term contracts ranging from one year and for one agreement, for the life of a specified production field. All production comes from our reserves. All pricing under these agreements is based upon both a combination of variable, 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, we had previously entered into 36,000 bpd of crude oil swap contracts, to hedge our 2005 Canadian dollar revenues and cash flows from potential changes in commodity pricing. For further particulars of these hedging arrangements, see the information under the heading “Derivative Financial Instruments”, under “Risk/Success Factors Affecting Performance” in the “Suncor Corporate Overview and Strategic Priorities” section of our MD&A, and Note 7 to our 2004 Consolidated Financial Statements, which note is incorporated by reference herein.

VOLUNTARY OIL SANDS RESERVES DISCLOSURE

Oil Sands Mining and In-Situ Firebag Reserves Reconciliation

The following table sets out, on a gross [5] basis, a reconciliation of our proved and probable reserves of synthetic crude oil from Oil Sands mining leases and bitumen, converted to synthetic crude oil for comparison purposes only, from in-situ Firebag leases, from December 31, 2003 to December 31, 2004, based on the GLJ Oil Sands Reports, in accordance with CSA Staff Notice 51-315, using 2004 Annual Average Differential Pricing assumptions.

(5) Suncor's undivided percentage interest in reserves, before deducting Crown royalties, freehold and overriding royalty interests.

Estimated Gross Proved and Probable Oil Sands Reserves Reconciliation

(millions of barrels of synthetic crude oil)(1)	Oil Sands Mining Leases(1)(2)			In-situ Firebag Leases(1), (3) (Constant Pricing)			Total Mining and In-situ(4)
	Proved	Probable	Proved & Probable	Proved(3)	Probable(5)	Proved & Probable	Proved & Probable
December 31, 2003	878	952	1,830	387	1,721	2,108	3,938
Revisions of previous estimates	140	(105)	35	110	179	289	324
Extensions and discoveries	—	—	—	—	—	—	—
Production	(79)	—	(79)	(3)	—	(3)	(82)
December 31, 2004	939	847	1,786	494	1,900	2,394	4,180

Notes:

(1) Synthetic crude oil reserves are based upon a net coker, or synthetic crude oil yield from bitumen of between 80 and 81% for reserves under Oil Sands mining leases and of 82% for reserves under Firebag in-situ Leases. Although virtually all of our bitumen from the Oil Sands mining leases is upgraded into synthetic crude oil, we have the option of selling the bitumen produced from our Firebag in-situ leases and/or upgrading this bitumen to synthetic crude oil and accordingly, these bitumen reserves are converted to synthetic crude oil for comparison purposes only.

(2) Our gross mining reserves are evaluated in part, based on the current mine plan and estimates of extraction recovery and upgrading yields, rather than an analysis based on constant dollar or forecast pricing assumptions.

(3) Under “Required U.S. OIL AND GAS AND MINING DISCLOSURE”, we reported proved reserves from our Firebag in-situ leases. The disclosure in the table above reports proved reserves from these leases and differs in the following three ways. Reserves from our Firebag in-situ leases are:

(a) disclosed in this table on a gross basis versus a net basis;

(b) converted from barrels of bitumen to barrels of synthetic crude oil in this table for comparability purposes only; and

(c) evaluated based on Annual Average Differential Pricing assumptions versus point-in-time Constant Cost and Pricing assumptions as at December 31. Accordingly, Firebag in-situ reserve estimates under “Required U.S. OIL AND GAS AND MINING DISCLOSURE – Proved Conventional Oil and Gas Reserves” and Firebag in-situ proved reserve estimates in this table differ materially.

(4) U.S. companies do not disclose probable reserves for non-mining properties. We voluntarily disclose our probable reserves for Firebag in-situ leases as we believe this information is useful to investors, and allows us to aggregate our mining and in-situ reserves into a consolidated total for our Oil Sands business. As a result, our Firebag in-situ estimates are not comparable to those made by U.S. companies.

SUNCOR EMPLOYEES

The following table shows the distribution of employees among our four business units and corporate office for the past two years.

	as at December 31,	
	2004	2003
Oil Sands	2,523	2,290
Natural Gas	202	188
Energy Marketing & Refining – Canada	629	605
Marketing & Refining – U.S.A.	630	633
Corporate (1)	621	515
Total (2)	4,605	4,231

Notes:

(1) The increases in 2004 numbers principally reflect the addition of in-house engineering, procurement, construction and project management personnel, as well as additional staff associated with our enterprise resource planning implementation project.

(2) In addition to our employees, we also use independent contractors to supply a range of services.

The Communications, Energy and Paperworkers Union Local 707 represents approximately 1,500 Oil Sands employees. We entered into a three-year collective agreement with the union effective May 1, 2004. The terms of the agreement include a 9.5% wage increase over a three-year term.

Employee associations represent approximately 170 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 the agreement will be automatically renewed on its anniversary. The National Automobile, Aerospace, Transportation and General Workers Union of Canada (CAW-Canada) Local 27 represents three employees at EM&R's London Terminal. A three year agreement was signed with the CAW-Canada effective April 1, 2003. Management believes our positive working relationship with these unions and associations will continue.

The local Paper, Allied-Industrial Chemical and Energy Workers International Union, represents approximately 150 employees at R&M's Denver area refinery. A four-year contract, assumed from ConocoPhillips in August 2003, will expire in January 2006.

RISK/SUCCESS FACTORS

Volatility of Crude Oil and Natural Gas Prices. Our future financial performance is closely linked to crude oil prices, and to a lesser extent natural gas prices. The prices 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 us are affected primarily by North American supply and demand and by prices of alternate sources of energy. All of these factors are beyond our 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 and bitumen. Oil and natural gas prices have fluctuated widely in recent years and we expect continued volatility and

uncertainty in crude oil and natural gas prices. A prolonged period of low crude oil and natural gas prices could affect the value of our 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 in particular could have an adverse impact on our financial condition and liquidity and results of operations. A key component of our business strategy is to produce sufficient natural gas to meet or exceed internal demands for natural gas purchased for consumption in our operations, creating a price hedge which reduces our exposure to gas price volatility. However, there are no assurances that we will be able to continue to increase production to keep pace with growing internal natural gas demands.

We cannot control the factors that influence supply and demand for, or the prices of, crude oil or natural gas. In prior years, before the suspension of our strategic hedging program in the second quarter of 2004 as noted below, we entered into strategic hedges under which we have fixed the price for 36,000 bpd of crude oil until December 31, 2005, and 14,000 GJ/day of natural gas until the end of 2005 and 4,000 GJ/day of natural gas from January 1, 2006 through to December 31, 2007. Our objective in entering into strategic hedges was to manage exposure to market volatility and lend more certainty to our ability to finance growth. For more particulars of our hedging position as of year-end 2004, see Note 7 of our 2004 Consolidated Financial Statements, which note is incorporated by reference herein, as well as "Risk/Success Factors Affecting Performance" in the "Suncor Overview and Strategic Priorities" section of our MD&A.

We concluded in the second quarter of 2004 that Suncor has the financial capacity to mitigate these risks without the use of a hedging program and accordingly, have suspended any future strategic crude oil hedge activity. No new hedges have been entered into since the suspension of this program. During periods of operational upset, including as a result of the fire at Suncor's Oil Sands Plant in January 2005, we are required to continue to make payments under our hedging program if the actual price was higher than the hedged price, even though the level of our production is reduced.

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

Volatility of Downstream Margins. EM&R and R&M operations are sensitive to wholesale and retail margins for their 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. We expect that margin and price volatility and overall marketplace competitiveness, including the potential for new market entrants, will continue. As a result, our operating results for EM&R and R&M can be expected to fluctuate.

Major Projects. There are certain risks associated with the execution of our major projects, including without limitation, each of the Firebag stages, the Voyageur growth strategy, and the "clean fuels" environmental capital projects in our downstream businesses. These risks include: our ability to obtain the necessary environmental and other 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; our 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 targets and objectives. Our management believes the execution of major projects presents issues that require prudent risk management. There are also risks associated with project cost estimates provided by us. Some cost estimates are provided at the conceptual stage of projects and prior to commencement or completion of the final scope design and detailed engineering needed to reduce the margin of error. Accordingly, actual costs can vary from estimates and these differences can be material.

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. Commercial application of this technology is not yet commonplace and accordingly in the absence of operating history there can be no assurances with respect to the sustainability of SAGD operations.

Dependence on Oil Sands business. The Company's significant capital commitment to further our growth projects at Oil Sands, including Firebag and Voyageur, may require us to forego investment opportunities in other segments of our operations. The completion of future projects to increase production at Oil Sands will further increase our dependence on the Oil Sands segment of our business. For example, in 2004, the Oil Sands business accounted for approximately 86% (86% in 2003) of our upstream production, 81% (81% in 2003) of our net earnings and 76% (78% in 2003) of our cash flow from operations. These percentages have been determined excluding the corporate and eliminations segment information.

Interdependence of Oil Sands Systems. The Oil Sands plant is susceptible to loss of production due to the interdependence of its component systems. Through growth projects, we expect to mitigate adverse impacts of 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 us 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. We compete in virtually every aspect of our business with other energy companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers. We believe the competition for our crude oil production is other Canadian conventional and synthetic sweet and sour crude oil producers.

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 their existing operations. It is difficult to assess the number, level of production and ultimate timing of all of the potential new producers or where existing production levels may increase. 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 from approximately 925,000 bpd to almost two and a half million bpd 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 fuel market demand and supply can fluctuate. Margins for diesel fuel are typically higher than the margins for synthetic and conventional crude oil. The above noted expansion plans of our competitors could result in an increase in the supply of diesel fuel and weaken 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 our downstream business units, EM&R and R&M, participate in new product markets, they could be exposed to margin risk and volatility from either cost and/or selling price fluctuations.

Need to Replace Conventional Natural Gas Reserves. Future natural gas reserves and production of the Company's NG business unit are highly dependent on our success in discovering or acquiring additional

reserves and exploiting our current reserve base. This impacts both our cash flow from such production and our ability to maintain a price hedge against growing consumption of natural gas in our operations. Without natural gas reserve additions through exploration and development or acquisition activities, our conventional natural gas reserves and production will decline over time as reserves are depleted. For example, in 2004, our average natural gas reservoir decline rates were in the 24% range (2003 – 24%). Decline rates will vary with the nature of the reservoir, life-cycle of the well, and other factors. Therefore historical 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[(6)] is insufficient to generate sufficient capital and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our conventional natural gas reserves could be impaired. In addition, the long term performance of the NG business is dependent on our 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 we will be able to find and develop or acquire additional reserves to replace production at acceptable costs.

Operating Hazards and Other Uncertainties. Each of our four principal businesses, Oil Sands, NG, EM&R, and R&M require high levels of

investment and have particular economic risks and opportunities. Generally, our operations are subject to hazards and risks such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts, power outages 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 our operations are subject to all of the risks normally incident to transporting, processing and storing crude oil, natural gas and other related products.

At Oil Sands, mining oil sands and producing bitumen through in-situ methods, extracting bitumen from the oil sands, and upgrading bitumen into synthetic crude oil and other products, involves particular risks and uncertainties. Oil Sands is susceptible to loss of production, slowdowns, shutdowns, or restrictions on our ability to produce higher value products due to the interdependence of its component systems. **For further information on the Oil Sands Fire, refer to page 4 of this AIF.** Severe climatic conditions at Oil Sands can cause reduced production during the winter season and in some situations can result in higher costs. While there is virtually no finding cost associated with oil sands resources, delineation of the 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 production at Oil Sands are largely fixed and, as a result, operating costs per unit are largely dependent on levels of production.

There are risks and uncertainties associated with NG's operations including 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.

Our downstream business units, EM&R and R&M are subject to all of the risks normally inherent with 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 we maintain 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 the company. Refer to note 11 to our 2004 Consolidated Financial Statements, which is incorporated by reference herein, for further description of our insurance coverage.

Land Claims. First Nations peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain First Nations peoples have filed a claim against the Government of Canada,

(6) Refer to "Non GAAP Financial Measures" on page ix of this AIF.

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. In addition, First Nations peoples have filed claims against industry participants generally, relating in part to land claims which may affect our Natural Gas business. We are unable to assess the effect, if any, these claims would have on our Oil Sands or other operations. Other than these claims, to our knowledge the First Nations peoples have asserted no other land claims against us.

Technology Risk. There are risks associated with growth and other capital 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 in-situ technology, cannot be assured.

Risks of International Investments. There are also inherent risks, including political and foreign exchange risk, in investing in business ventures internationally. Our capital projects planned for the R&M business are expected to be funded in large part from Canadian operations. A weaker Canadian dollar relative to the U.S. dollar would result in higher funding requirements for these projects. However, a weaker Canadian dollar would positively impact the Canadian dollar value of earnings from R&M. (See "Exchange Rate Fluctuations", below). Other than the R&M business, we do not have material international investments, although we continue to assess downstream integration, coal bed methane and conventional natural gas opportunities in the U.S.

Interest Rate Risk. We are exposed to fluctuations in short-term Canadian interest rates as a result of the use of floating rate debt. We maintain a substantial portion of our debt capacity in revolving, floating rate bank facilities and commercial paper, with the remainder issued in fixed rate borrowings. To minimize our exposure to interest rate fluctuations, we occasionally enter 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 our MD&A.

Exchange Rate Fluctuations. Our 2004 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 our revenue is received by reference to U.S. dollar denominated prices, and a significant portion of our debt is denominated in U.S. dollars. Crude oil and natural gas prices are generally based in U.S. dollars, while a large portion of our sales of refined products are 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.

Environmental Regulation and Risk. Environmental regulation affects nearly all aspects of our operations. These regulatory regimes are laws of general application that apply to us in the same manner as they apply to other companies and enterprises in the energy industry. The regulatory regimes require us 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, we expect 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 to air and discharges to water; issues relating to global climate change, land reclamation and restoration; Great Lakes water quality; and reformulated gasoline to support lower vehicle emissions (For example, see the discussion relating to our clean fuels capital projects, under the "Three Year Highlights" section of this AIF.). Changes in environmental regulation could have a potentially adverse effect on us 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 us. 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.

Another area of risk involves reclaiming tailings ponds. To reclaim tailings ponds, we are using a process referred to as consolidated tailings technology. At this time, no ponds have been fully reclaimed using this technology. The success and time to reclaim the tailings ponds could increase or decrease the current asset retirement cost estimates. We continue to monitor and assess other possible technologies and/or modifications to the consolidated tailings process now being used.

We are required to and have posted annually with Alberta Environment an irrevocable letter of credit equal to $0.03 per bbl of crude oil produced as of December 31, 2004 ($14 million as at December 31, 2004) as security for the estimated cost of our reclamation activity on Oil Sands Mining Leases 86 and 17. For the Millennium and Steepbank mines, we have posted an irrevocable letter of credit equal to approximately $78 million, representing security for the estimated cost of reclamation activities up to the end of December 2004. For Firebag, we have posted an irrevocable letter of credit equal to approximately $9 million, representing security for the estimated cost of reclamation activities relating to Firebag up to the end of December 2004. For more information about our reclamation and environmental remediation obligations, refer to "Asset Retirement Obligations" under "Critical Accounting Estimates" in the "Suncor Overview and Strategic Priorities" section of our MD&A.

Over the past few years, legislation has been passed in Canada and the United States to reduce permitted levels of sulphur in transportation fuels. For a discussion of projects planned or underway at our EM&R and R&M operations, see the information under the EM&R and R&M sections of "Narrative Description of the Business", and under "Three Year Highlights", in this Annual Information Form. Projects to retrofit existing facilities to comply with these standards are subject to all risks inherent in large capacity projects, and to the additional risk that failure to meet legislated deadlines could have a material impact on the Company's ability to market its products, potentially having a material impact on revenues and earnings.

Uncertainty of Reserve and Resource Estimates. The reserves data and resource estimates for our Oil Sands and Natural Gas (NG) business units, included in our Annual Information Form, represent estimates only. There are numerous uncertainties inherent in estimating quantities and quality of these proved and probable reserves and resources, including many factors beyond our control.

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, pricing assumptions, future royalties 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 and resource 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 of 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 evaluation of mining reserves does not take into account the economic aspects of future reserves. Our actual production,

revenues, royalties, taxes and development and operating expenditures with respect to our reserves will vary from such estimates, and such variances could be material.

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

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 us unable to liquidate or offset a position, or unable to do so at or near the previous market price; we will not receive funds or instruments from our counterparty at the expected time; the counterparty will fail to perform an obligation owed to us; we will suffer a loss as a result of human error or deficiency in our systems or controls; or we will suffer a loss as a result of contracts being unenforceable or transactions being inadequately documented. A separate risk management function within the company develops and monitors practices and policies and provides independent verification and valuation of our trading and marketing activities. However, we may experience significant financial losses as a result of these risks.

Governmental Regulation. The oil and gas industry in Canada and the United States, including the oil sands industry and our downstream

segment, operates under federal, provincial, state 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, 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, we 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 our costs and have a material adverse effect on our 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, 2004 is derived from our 2004 Consolidated Financial Statements. Our consolidated financial statements for each of the years in the three-year period ended December 31, 2004 have been audited by PricewaterhouseCoopers LLP, Chartered Accountants. The information set forth below should be read in conjunction with our MD&A and our 2004 Consolidated Financial Statements.

($ millions except per share amounts)	Year ended December 31,(1) 2004	2003	2002
Revenues	8,621	6,571	5,032
Net earnings	1,100	1,075	749
Per common share (undiluted)	2.40	2.41	1.61
Per common share (diluted)	2.36	2.24	1.58
Cash flow from operations	2,021	2,079	1,440
Capital, acquisition and exploration expenditures	1,846	1,588	877

($ millions)	Year ended December 31, 2004	2003
Total assets	11,804	10,501
Long-term debt	2,217	2,448
Accrued liabilities and other(1)	749	616
Shareholders' equity	4,897	4,355

Note:

(1) See Note 8 to our 2004 Consolidated Financial Statements, which is incorporated by reference herein.

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

Revenues from: ($ millions)	2004	%	2003	%
Transportation fuel sales	4,293	50	2,986	45
Crude oil sales	3,064	36	2,371	36
Other	1,261	14	1,208	19
Total	8,618 (1)	100	6,565(1)	100

Note:

(1) Excludes interest income.

Dividend Policy and Record

Our Board of Directors has established a policy of paying dividends on a quarterly basis. We review our policy from time to time in light of our financial position, financing requirements for growth, cash flow and other factors which our Board of Directors considers relevant. In the second quarter of 2004, our Board of Director's approved an increase in the quarterly dividend to $0.06 per share from $0.05 per share.

During 1999, we 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). Our preferred securities were unsecured junior subordinated debt, due in 2048 and we redeemed these securities on March 15, 2004 for proceeds equal to the original principal amount of the preferred securities plus accrued and unpaid interest as at March 15, 2004. For accounting purposes, the preferred securities were classified as share capital in the consolidated balance sheet and the interest distributions thereon, net of income taxes, were classified as dividends in our 2004 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 we paid to shareholders during the last three years.

	Year Ended December 31,		
	2004	2003	2002
Common Shares cash dividends	$ 0.23	$ 0.1925	$ 0.17
Preferred securities cash interest distributions(1)	$ 0.02	$ 0.10	$ 0.11
Dividends paid in common shares	—	—	—

Note:

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

Our MD&A, dated February 23, 2005, is incorporated by reference herein and forms an integral part of this Annual Information Form, and should be read in conjunction with our 2004 Consolidated Financial Statements and the notes thereto.

DESCRIPTION OF CAPITAL STRUCTURE

General Description of Capital Structure

Our authorized capital consists of an unlimited number of common shares without nominal or par value and an unlimited number of preferred shares without nominal or par value, issuable in series. As at December 31, 2004, a total of 454,240,626 common shares were issued and outstanding and no preferred shares had been issued.

Each common share entitles the holder to receive notice of and to attend all meetings of our shareholders, other than meetings at which only the holders of another class or series are entitled to vote. Each common share entitles the holder to one vote. The holders of common shares, in the discretion of the board of directors, are entitled to receive out of any monies properly applicable to the payment of dividends, and after the payment of any dividends payable on the preferred shares of any series or any other series ranking prior to the common shares as to the payment of dividends, any dividends declared and payable on the common shares. Upon any liquidation, dissolution or winding-up of Suncor, or other distribution of our assets among our shareholders for the purposes of winding-up our affairs, the holders of the common shares are entitled to share on a share-for-share basis in the distribution, except for the prior rights of the holders of the preferred shares of any series, or any other class ranking prior to the common shares. There are no pre-emptive or conversion rights, and the common shares are not subject to redemption. All common shares currently outstanding and to be outstanding upon exercise of outstanding options are, or will be, fully paid and non-assessable.

Ratings

At December 31, 2004, our current long-term senior debt ratings are, A(low) by Dominion Bond Rating Service, A3 by Moody's Investor Service and A- by Standard & Poor's and our current commercial paper debt rating is R-1(low) (Dominion Bond Rating Services). All debt ratings have a stable outlook. In 2003, Moody's removed its negative outlook in response to our debt reduction over the previous two years.

Dominion Bond Rating Service's ("DBRS") credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A

rating of A (low) by DBRS is the third highest of nine categories and is assigned to debt securities considered to be of satisfactory credit quality. Protection of interest and principal is still substantial, but the degree of strength is less that with AA rated entities. Entities in the A category may be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher rated companies. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category. The "high" and "low" grades are not used for the AAA category.

Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. A rating of A3 by Moody's is the third highest of nine categories and is assigned to debt securities which are considered upper-medium grade obligations and are subject to low credit risk. Moody's appends numerical modifiers 1, 2 or 3 to each generic rating classification. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates that the issue ranks in the lower end of its generic rating category.

Standard and Poor's ("S&P") credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of A- by S&P is the third highest of eleven categories and indicates that the obligor is somewhat more susceptible to adverse effects of changes in circumstances and economic conditions than obligors in the higher-rated categories. However, the obligor's capacity to meet its financial commitment on the obligation is still strong. The addition of a plus (+) or minus (-) designation after a rating indicates the relative standing within a particular rating category.

DBRS's commercial paper credit ratings are on a on a short-term debt rating scale that ranges from R-1(high) to D, which represent the range

from highest to lowest quality of such securities rated. A rating of R-1(low) by DBRS is the third highest of ten categories and is assigned to debt securities considered to be of satisfactory credit quality. The overall strength and outlook for key liquidity, debt, and profitability ratios is not normally as favourable as with higher rating categories, but these considerations are still respectable, and any qualifying negative factors that exist are considered manageable, and the entity is normally of sufficient size to have some influence in its industry.

The credit ratings accorded to the notes by the rating agencies are not recommendations to purchase, hold or sell the notes inasmuch as such ratings do not comment as to the market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

MARKET FOR OUR SECURITIES

Our common shares are listed on the Toronto Stock Exchange in Canada, and on the New York Stock Exchange in the United States.

Price Range and Trading Volume of Common Shares

Toronto Stock Exchange
2004

	Price Range		Trading Volume
	High	Low	(000's)
January	35.05	31.62	33,917
February	35.52	32.82	26,579
March	38.02	34.60	37,385
April[	36.80	30.95	42,573
May	35.83	31.38	36,158
June	36.35	31.94	28,985
July	38.75	32.80	35,606
August	39.75	35.29	36,023
September	41.49	36.38	30,910
October	44.49	39.66	34,179
November	42.40	38.53	30,231
December	43.00	38.20	25,599

New York Stock Exchange
2004

	Price Range		Trading Volume
	High	Low	(000's)
January	27.03	24.68	15,517
February	26.73	24.70	13,732
March	28.75	26.06	15,872
April	28.09	22.55	21,544
May	25.95	23.20	17,155
June	26.68	23.60	20,555
July	29.18	24.90	18,114
August	30.00	27.01	24,468
September	32.63	27.84	21,938
October	36.15	31.35	25,285
November	35.54	32.11	20,834
December	35.69	31.16	20,417

DIRECTORS AND EXECUTIVE OFFICERS

Directors

Reference is made to the information under the heading, "Election of Directors" on pages 4 - - 7 inclusive of Suncor's Management Proxy Circular dated March 24, 2005 for information regarding our directors, which information is incorporated by reference into this Annual Information Form.

Executive Officers

The following individuals are the executive officers of Suncor. Except where otherwise indicated, these individuals held the offices set out opposite their respective names as at December 31, 2004 and as of the date hereof.

Name and Municipality of Residence	Office(1)
J. KENNETH ALLEY Calgary, Alberta	Senior Vice President and Chief Financial Officer

MIKE M. ASHAR Denver, Colorado	Executive Vice President, Refining and Marketing – U.S.A.
DAVID W. BYLER Cochrane, Alberta	Executive Vice President, Natural Gas and Renewable Energy
RICHARD L. GEORGE Calgary, Alberta	President and Chief Executive Officer
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	Executive Vice President, Major Projects
THOMAS L. RYLEY Toronto, Ontario	Executive Vice President, Energy, Marketing and Refining - Canada
STEVEN W. WILLIAMS Fort McMurray, Alberta	Executive Vice President, Oil Sands

Note:

(1) Offices shown are positions held by the officers in relation to business units of Suncor Energy Inc. and its subsidiaries on a consolidated basis. On a legal entity basis, Mr. Ashar is President of Suncor Energy (U.S.A.) Inc., Suncor's U.S. based downstream subsidiary, Mr. Ryley is the President of Suncor's Canadian based downstream subsidiaries, Suncor Energy Marketing Inc. and Suncor Energy Products Inc., respectively, and Mr. Nabholz is Executive Vice-President of Suncor Energy Services Inc., which provides major projects and other shared services to the Suncor group of companies.

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, we confirm that, as at the date hereof:

(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 relevant issuer access to any exemption under Canadian securities legislation for a period of more than 30 consecutive days;

(b) was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

(c) became bankrupt or 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 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 securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a 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 become 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.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer, or principal holder of Suncor securities or any associate or affiliate of these persons has, or has had, any material interest in any transaction or any proposed transaction that has materially affected or will materially affect us or any of our affiliates, within the three most recently completed financial years or during the current financial year.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for our common shares is Computershare Trust Company of Canada at its principal offices in Calgary, Montreal, Toronto and Vancouver and Computershare Trust Company Inc. in Denver, Colorado.

INTERESTS OF EXPERTS

As at the date hereof the principles of Gilbert Laustsen Jung Associates Ltd., as a group, beneficially owned, directly or indirectly, less than 1% of our outstanding securities, including the securities of our associates and affiliates.

FEES PAID TO AUDITORS

Fees Paid to Auditors

Reference is made to the information under the heading, “Appointment of Auditors” on page 8 of Suncor’s Management Proxy Circular dated March 24, 2005 for information regarding fees paid by Suncor to its auditors for the last two completed fiscal years, which information is incorporated by reference into this Annual Information Form.

Audit Committee Pre-Approval Policies for Non Audit Services

Our Audit Committee has considered whether the provision of services other than audit services is compatible with maintaining the auditors’ independence and has a policy governing the provision of these services. A copy of our policy relating to Audit Committee approval of fees paid to our auditors, in compliance with the *Sarbanes Oxley Act of 2002,* is attached as Schedule ”A” to this Annual Information Form.

RELIANCE ON EXEMPTIVE RELIEF

We are reporting our reserves data in accordance with, and are relying on, the terms of the following MRRS Decision Document: In the Matter of the Securities Legislation of Alberta, British Columbia, Saskatchewan, Manitoba, Ontario, Quebec, Nova Scotia, Newfoundland and Labrador, Yukon, Northwest Territories and Nunavut AND In the Matter of The Mutual Reliance Review System for Exemptive Relief Applications AND In the Matter of Suncor Energy Inc., December 22, 2003 (the “Decision Document”).

Our reserves data consists of the following:

- net proved working interest oil and gas reserve quantities relating to oil and gas operations, other than mining, estimated as at December 31, 2004 using constant dollar cost and pricing assumptions as of a point in time, namely December 31, 2004, and the related standardized measure;

- gross proved and probable working interest oil reserve quantities relating to surface mineable oil sands operations estimated as at December 31, 2004; and

- gross proved and probable working interest oil and gas reserve quantities relating to Firebag in-situ leases, estimated as at December 31, 2004 using constant dollar cost and pricing assumptions, generally intended to represent a normalized annual average for the year in accordance with CSA Staff Notice 51-315.

Our estimates of reserves and related standardized measure of discounted future net cash flows (the “standardized measure”) were evaluated or reviewed in accordance with the standards set out in the Canadian Oil and Gas Evaluation Handbook (the “COGE Handbook”) modified to the extent necessary to reflect the terminology and standards of US disclosure requirements, including:

- the information required by the United States Financial Accounting Standards Board, including Financial Accounting Standard No. 69;

- the information required by SEC Industry Guide 2 Disclosure of Oil and Gas Operations, as amended from time to time; and

- certain other information required in accordance with US disclosure practices.

If we had been reporting our reserves data in accordance with National Instrument 51-101 and had not been relying on the terms of the Decision Document, we would have been required to report gross and net reserves data consisting of the following:

- proved working interest oil and gas reserve quantities relating to oil and gas operations using constant prices and costs and related net present value of future net revenue, discounted at 10%; and

- proved and probable working interest oil and gas reserve quantities relating to oil and gas operations using forecast prices and costs and related net present value of future net revenue, discounted at 5%, 10%, 15% and 20%.

LEGAL PROCEEDINGS

There are no legal proceedings to which we are a party or of which any of our property is the subject, nor are there any proceedings known by us to be contemplated that involves a claim for damages exceeding ten percent of our current assets, other than the claims by John S. Rendall against us, our President and Chief Executive Officer, Syncrude (Canada), Inc., Shell (Canada) Inc., Exxon-Mobil, Inc., Deutsche Bank, AG, Raymond and Rawl (Exxon), Bob Pitmann, Al Hyndman, Helmar Kopper and Merrill Lynch and the claim by W. Jack Butler against us, Syncrude (Canada), Inc., Deutsche Morgan Grenfell, Inc., Exxon-Mobil Corporation, Deutsche Bank, AG and Merrill Lynch, Pierce Fenner and Smith, Inc., both recently dismissed by the Second Judicial District Court, County of Bernalillio, New Mexico, USA and subsequently appealed by the Plaintiffs. The total amount of the claims is $21.5 billion, plus unquantified damages and involves an allegation that we and various other defendants caused the bankruptcy of Solv-Ex. The claims involve allegations of breach of contract, fraud, aiding and abetting tortuous conduct, interference with economic advantage, breach of fiduciary duty, aiding and abetting such breaches, breach of trust, conspiracy under U.S. racketeering statutes and anti-trust law, intentional infliction of emotional distress and malicious abuse of process. The appeals were filed in early 2005.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in our most recent management proxy circular for our most recent annual meeting of our shareholders that involved the election of directors. Additional financial information is provided in our 2004 Consolidated Financial Statements.

Further information about Suncor, filed with Canadian securities commissions and the United States Securities and Exchange Commission (SEC), including periodic quarterly and annual reports and the Annual Information Form (AIF/40-F) is available online at www.sedar.com and www.sec.gov. In addition, our Standards of Business Conduct Code is available online at www.suncor.com.

SCHEDULE "A"

*****Approved and Accepted April 28, 2004*****

SUNCOR ENERGY INC.
POLICY AND PROCEDURES FOR PRE-APPROVAL OF AUDIT
AND NON-AUDIT SERVICES

Pursuant to the Sarbanes-Oxley Act of 2002 and Multilateral Instrument 52-110, the Securities and Exchange Commission and the Ontario Securities Commission respectively has adopted final rules relating to audit committees and auditor independence. These rules require the Audit Committee of Suncor Energy Inc ("Suncor") to be responsible for the appointment, compensation, retention and oversight of the work of its independent auditor. The Audit Committee must also pre-approve any audit and non-audit services performed by the independent auditor or such services must be entered into pursuant to pre-approval policies and procedures established by the Audit Committee pursuant to this policy.

I. STATEMENT OF POLICY

The Audit Committee has adopted this Policy and Procedures for Pre-Approval of Audit and Non-Audit Services (the "Policy"), which sets forth the procedures and the conditions pursuant to which services proposed to be performed by the independent auditor will be pre-approved. The procedures outlined in this Policy are applicable to all Audit, Audit-Related, Tax Services and All Other Services provided by the independent auditor.

II. RESPONSIBILITY

Responsibility for the implementation of this Policy rests with the Audit Committee. The Audit Committee delegates its responsibility for administration of this policy to management. The Audit Committee shall not delegate its responsibilities to pre-approve services performed by the independent auditor to management.

III. DEFINITIONS

For the purpose of these policies and procedures and any pre-approvals:

a) "Audit services" include services that are a necessary part of the annual audit process and any activity that is a necessary procedure used by the auditor in reaching an opinion on the financial statements as is required under generally accepted auditing standards ("GAAS"), including technical reviews to reach audit judgement on accounting standards;

The term "audit services" is broader than those services strictly required to perform an audit pursuant to GAAS and include such services as:

i) the issuance of comfort letters and consents in connections with offerings of securities;

ii) the performance of domestic and foreign statutory audits;

iii) Attest services required by statute or regulation;

iv) Internal control reviews; and

v) Assistance with and review of documents filed with the Canadian Securities administrators, the Securities and Exchange Commission and other regulators

---

having jurisdiction over Suncor and its subsidiaries, and responding to comments from such regulators;

b) "Audit-related services" are assurance (e.g. due diligence services) and related services traditionally performed by the external auditors and that are reasonably related to the performance of the audit or review of financial statements and not categorized under "audit fees" for disclosure purposes.

"Audit-related services" include:

i) employee benefit plan audits, including audits of employee pension plans;

ii) due diligence related to mergers and acquisitions;

iii) consultations and audits in connection with acquisitions, including evaluating the accounting treatment for proposed transactions;

iv) internal control reviews;

v) attest services not required by statute or regulation; and

vi) consultations regarding financial accounting and reporting standards;

Non-financial operational audits are not "audit-related" services;

c) "Tax services" include but are not limited to services related to the preparation of corporate and/or personal tax filings, tax due diligence as it pertains to mergers, acquisitions and/or divestitures and tax planning;

d) "All other services" consist of any other work that is neither an Audit service, nor an Audit-Related service nor a Tax service, the provision of which by the independent auditor is not expressly prohibited by Rule 2-01(c)(7) of Regulation S-X under the Securities and Exchange Act of 1934, as amended. (See Appendix A for a summary of the prohibited services.)

IV. GENERAL POLICY

The following general policy applies to all services provided by the independent auditor:

- All services to be provided by the independent auditor will require specific pre-approval by the Audit Committee. The Audit Committee will not approve engaging the independent auditor for services which can reasonably be classified as "tax services" or "all other services" unless a compelling business case can be made for retaining the independent auditor instead of another service provider.

- The Audit Committee will not provide pre-approval for services to be provided in excess of twelve months from the date of the pre-approval, unless the Audit Committee specifically provides for a different period.

- The Audit Committee has delegated authority to pre-approve services with an estimated cost not exceeding $100,000 in accordance with this Policy to the Chairman of the Audit Committee. The delegate member of the Audit Committee must report any pre-approval decision to the Audit Committee at its next meeting.

- The Chairman of the Audit Committee may delegate his authority to pre-approve services to another sitting member of the Audit Committee provided that the recipient has also

---

been delegated the authority to act as Chairman of the Audit Committee in the Chairman's absence. A resolution of the Audit Committee is required to evidence the Chairman's delegation of authority to another Audit Committee member under this policy.

- The Audit Committee will, from time to time, but no less than annually, review and pre-approve the services that may be provided by the independent auditor.

- The Audit Committee must establish pre-approval fee levels for services provided by the independent auditor on an annual basis. On at least a quarterly basis, the Audit Committee will be provided with a detailed summary of fees paid to the independent auditor and the

nature of the services provided and a forecast of fees and services that are expected to be provided during the remainder of the fiscal year.

- The Audit Committee will not approve engaging the independent auditor to provide any prohibited non-audit services as set forth in Appendix A.

- The Audit Committee shall evidence their pre-approval for services to be provided by the independent auditor as follows:

  a) In situations where the Chairman of the Audit Committee pre-approves work under his delegation of authority, the Chairman will evidence his pre-approval by signing and dating the pre-approval request form, attached as Appendix B. If it is not practicable for the Chairman to complete the form and transmit it to the Company prior to engagement of the independent audit, the Chairman may provide verbal or email approval of the engagement, followed up by completion of the request form at the first practical opportunity.

  b) In all other situations, a resolution of the Audit Committee is required.

- All audit and non-audit services to be provided by the independent auditors shall be provided pursuant to an engagement letter that shall:

  a) be in writing and signed by the auditors

  b) specify the particular services to be provided

  c) specify the period in which the services will be performed

  d) specify the estimated total fees to be paid, which shall not exceed the estimated total fees approved by the Audit Committee pursuant to these procedures, prior to application of the 10% overrun.

  e) include a confirmation by the auditors that the services are not within a category of services the provision of which would impair their independence under applicable law and Canadian and U.S. generally accepted accounting standards.

- The Audit Committee pre-approval permits an overrun of fees pertaining to a particular engagement of no greater than 10% of the estimate identified in the associated engagement letter. The intent of the overrun authorization is to ensure on an interim basis only, that services can continue pending a review of the fee estimate and if required, further Audit Committee approval of the overrun. If an overrun is expected to exceed the 10% threshold, as soon as the overrun is identified, the Audit Committee or its designate must be notified and an additional pre-approval obtained prior to the engagement continuing.

V. RESPONSIBILITIES OF EXTERNAL AUDITORS

To support the independence process, the independent auditors will:

a) Confirm in each engagement letter that performance of the work will not impair independence;

b) Satisfy the Audit Committee that they have in place comprehensive internal policies and processes to ensure adherence, world-wide, to independence requirements, including robust monitoring and communications;

c) Provide communication and confirmation to the Audit Committee regarding independence on at least a quarterly basis;

d) Maintain registration by the Canadian Public Accountability Board and the U.S. Public Company Accounting Oversight Board;

e) Review their partner rotation plan and advise the Audit Committee on an annual basis.

In addition, the external auditors will:

a) Provide regular, detailed fee reporting including balances in the “Work in Progress” account;

b) Monitor fees and notify the Audit Committee as soon as a potential overrun is identified.

VI. DISCLOSURES

Suncor will, as required by applicable law, annually disclose its pre-approval policies and procedures, and will provide the required disclosure concerning the amounts of audit fees, audit-related fees, tax fees and all other fees paid to its outside auditors in its filings with the SEC.

* * *

Appendix A

Prohibited Non-Audit Services

An external auditor is not independent if, at any point during the audit and professional engagement period, the auditor provides the following non-audit services to an audit client.

Bookkeeping or other services related to the accounting records or financial statements of the audit client. Any service, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor's financial statements, including:

Maintaining or preparing the audit client's accounting records;
Preparing Suncor's financial statements that are filed with the Securities and Exchange Commission ("SEC") or that form the basis of financial statements filed with the SEC; or
Preparing or originating source data underlying Suncor's financial statements.

Financial information systems design and implementation. Any service, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor's financial statements, including:

Directly or indirectly operating, or supervising the operation of, Suncor's information system or managing Suncor's local area network; or
Designing or implementing a hardware or software system that aggregates source data underlying the financial statements or generates information that is significant to Suncor's financial statements or other financial information systems taken as a whole.

Appraisal or valuation services, fairness opinions or contribution-in-kind reports. Any appraisal service, valuation service or any service involving a fairness opinion or contribution-in-kind report for Suncor, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor's financial statements.

Actuarial services. Any actuarially-oriented advisory service involving the determination of amounts recorded in the financial statements and related accounts for Suncor other than assisting Suncor in understanding the methods, models, assumptions, and inputs used in computing an amount, unless it is reasonable to conclude that the results of these services will not be subject to audit procedures during an audit of Suncor's financial statements.

Internal audit outsourcing services. Any internal audit service that has been outsourced by Suncor that relates to Suncor's internal accounting controls, financial systems, or financial statements, unless it is reasonable to conclude that the result of these services will not be subject to audit procedures during an audit of Suncor's financial statements.

Management functions. Acting, temporarily or permanently, as a director, officer, or employee of Suncor, or performing any decision-making, supervisory, or ongoing monitoring function for Suncor.

Human resources.

Searching for or seeking out prospective candidates for managerial, executive, or director positions;
Engaging in psychological testing, or other formal testing or evaluation programs;
Undertaking reference checks of prospective candidates for an executive or director position;
Acting as a negotiator on Suncor's behalf, such as determining position, status or title, compensation, fringe benefits, or other conditions of employment; or
Recommending, or advising Suncor to hire a specific candidate for a specific job (except that an accounting firm may, upon request by Suncor, interview candidates and advise Suncor on the candidate's competence for financial accounting, administrative, or control positions.)

Broker-dealer, investment adviser or investment banking services. Acting as a broker-dealer (registered or unregistered), promoter, or underwriter, on behalf of Suncor, making investment decisions on behalf of Suncor or otherwise having discretionary authority over Suncor's investments, executing a transaction to buy or sell Suncor's investment, or having custody of Suncor's assets, such as taking temporary possession of securities purchased by Suncor.

Legal services. Providing any service to Suncor that, under circumstances in which the service is provided, could be provided only by someone licensed, admitted, or otherwise qualified to practice law in the jurisdiction in which the service is prohibited.

Expert services unrelated to the audit. Providing an expert opinion or other expert service for Suncor, or Suncor's legal representative, for the purpose of advocating Suncor's interest in litigation or in a regulatory or administrative proceeding or investigation. In any litigation or regulatory or administrative proceeding or investigation, an accountant's independence shall not be deemed to be impaired if the accountant provides factual accounts, including testimony, of work performed or explains the positions taken or conclusions reached during the performance of any service provided by the accountant for Suncor.

Appendix B

Pre-approval Request Form

NATURE OF WORK	**ESTIMATED FEES (Cdn $)**

Total

Date Signature

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER INFORMATION

This is the form referred to in item 3 of section 2.1 of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("*NI 51-101*"), as amended pursuant to the MRRS Decision Document dated December 22, 2003, *In the Matter of Suncor Energy Inc.* (the "Decision Document").

Terms to which a meaning is ascribed in the Decision Document have the same meaning in this form.

Management of Suncor Energy Inc. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas and surface mineable oil sands activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) proved working interest oil and gas reserve quantities relating to oil and gas operations, other than mining, estimated as at December 31, 2004 using constant dollar cost and pricing assumptions as of a point in time, namely December 31, 2004, and the related standardized measure;

(b) proved and probable working interest oil reserve quantities relating to surface mineable oil sands operations estimated as at December 31, 2004; and

(c) proved and probable working interest oil and gas reserve quantities relating to Firebag in-situ leases, estimated as at December 31, 2004 using constant dollar cost and pricing assumptions, generally intended to represent a normalized annual average for the year in accordance with CSA Staff Notice 51-315.

Gilbert Laustsen Jung Associates Ltd., independent qualified reserves evaluators, have evaluated the Company's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Audit Committee of the board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Audit Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas and surface mineable oil sands activities and has reviewed that information with management. The board of directors has, on the recommendation of the Audit Committee, approved

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas and surface mineable oil sands information;

(b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

"RICHARD L. GEORGE"

RICHARD L. GEORGE
President and Chief Executive Officer

"J. KENNETH ALLEY"

J. KENNETH ALLEY

Senior Vice President and Chief Financial Officer

"JOHN T. FERGUSON"

JOHN T. FERGUSON
Director

"JR SHAW"

JR SHAW
Chairman of the Board of Directors

March 21, 2005

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

REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR

Suncor Energy Inc.
P.O. Box 38
112 – 4th Avenue S.W.
Calgary, AB T2P 2V5

To: The Board of Directors of Suncor Energy Inc.

Re: Form 51-101F2, as modified in accordance with exemptions from National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") contained in the MRRS Decision Document dated December 22, 2003, *In the Matter of Suncor Energy Inc.* (the "Decision Document")

We are providing this report in accordance with the terms of the Decision Document and any capitalized terms, not otherwise defined in this report, shall have the same meaning as set out in the Decision Document.

We have evaluated the Company's reserves data as at December 31, 2004. The reserves data consist of the following:

proved working interest oil and gas reserve quantities relating to oil and gas operations, other than mining, estimated as at December 31, 2004 using constant dollar cost and pricing assumptions as of a point in time, namely December 31, 2004, and the related standardized measure;
proved and probable working interest oil reserve quantities relating to surface mineable oil sands operations estimated as at December 31, 2004; and
proved and probable working interest oil and gas reserve quantities relating to Firebag in-situ leases, estimated as at December 31, 2004 using constant dollar cost and pricing assumptions, generally intended to represent a normalized annual average for the year in accordance with CSA Staff Notice 51-315.

The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We evaluated or reviewed the Company's estimates of reserves and related future net revenue (or, where applicable, related standardized measure of discounted future net cash flows (the standardized measure)) in accordance with the standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") modified to the extent necessary to reflect the terminology and standards of the US Disclosure Requirements.

Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook, as modified to the extent necessary to reflect the terminology and standards of the US Disclosure Requirements.

The following table sets forth the estimated standardized measure of future cash flows (before deducting income taxes) attributed to proved oil and gas reserve quantities not related to mining operations, estimated using constant prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended, December 31, 2004:

Preparation Date of Report	Location of Reserves	Standardized Measure of Future Cash Flows for Proved Oil and Gas Reserve Quantities (before income taxes, 10% discount rate) Evaluated	Reviewed	Total
February 17, 2005	Canada	$ 1,337 million (94%)	$ 85 million (6%)	$ 1,422 million (100%)

In addition, all proved plus probable company gross reserves have been evaluated for Suncor's oil sands mining properties located in Canada and all reserves and resources have been evaluated or reviewed for all of Suncor's oil and gas plus mining operations.

In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, as modified or amended as set out above. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

We have no responsibility to update our reports evaluating reserves data of the Company by us for the year ended December 31, 2004 for events and circumstances occurring after the preparation dates of our reports.

Reserves are estimates only, and not exact quantities. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GILBERT LAUSTSEN JUNG ASSOCIATES LTD.,
Calgary, Alberta, Canada

"GILBERT LAUSTSEN JUNG ASSOCIATES LTD."

Harry Jung, P. Eng.
President

Calgary, Alberta, Canada
March 21, 2005

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.

DISCLOSURE CONTROLS AND PROCEDURES

See page 34 and 35 of Exhibit 99-2.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

See page 55 of Exhibit 99-1.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See page 56 and 57 of Exhibit 99-1.

AUDIT COMMITTEE FINANCIAL EXPERT

See pages 25 and 37 of Appendix B of Exhibit 99-3.

CODE OF ETHICS

See pages 26 and 31 of Exhibit 99-3 and page 45 of our Annual Information Form.

FEES PAID TO PRINCIPAL ACCOUNTANT

See page 8 of Exhibit 99-3.

AUDIT COMMITTEE PRE-APPROVAL POLICIES

See page 44 of Annual Information Form.

APPROVAL OF NON-AUDIT SERVICES

See page 8 of Exhibit 99-3.

OFF-BALANCE SHEET ARRANGEMENTS

See pages 22 and 23 of Exhibit 99-2.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See pages 22 and 23 of Exhibit 99-2.

IDENTIFICATION OF THE AUDIT COMMITTEE

See page 28 of Exhibit 99-3.

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: March 30, 2005

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

EXHIBIT INDEX

Exhibit No.	Description
99-1	Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2004, including reconciliation to U.S. GAAP (Note 19)
99-2	Management's Discussion and Analysis for the fiscal year ended December 31, 2004, dated February 23, 2005
99-3	Excerpts from pages 8, 25, 26, 28, 31 and 37 inclusive of Suncor Energy Inc.'s Management Proxy Circular dated February 28, 2005
99-4	Consent of PricewaterhouseCoopers LLP
99-5	Consent of Gilbert Laustsen Jung Associates Ltd.
99-6	Certificate of President and Chief Executive Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-7	Certificate of Senior Vice President and Chief Financial Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-8	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
99-9	Certificate of the Senior Vice President 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

management's statement of responsibility for financial reporting

The management of Suncor Energy Inc. is responsible for the presentation and preparation of the accompanying consolidated financial statements of Suncor Energy Inc. on pages 58 to 92 and all related financial information contained in this Annual Report, including Management's Discussion and Analysis.

We, as Suncor Energy Inc.'s Chief Executive Officer and Chief Financial Officer, will certify Suncor's annual disclosure document filed with the United States Securities and Exchange Commission (Form 40-F) as required by the United States Sarbanes-Oxley Act.

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. They include certain amounts that are based on estimates and judgments relating to matters not concluded by year-end. Financial information presented elsewhere in this Annual Report is consistent with that contained in the consolidated financial statements.

In management's opinion, the consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies adopted by management as summarized on pages 58 to 61. If alternate accounting methods exist, management has chosen those policies it deems the most appropriate in the circumstances. In discharging its responsibilities for the integrity and reliability of the financial statements, management maintains and relies upon a system of internal controls designed to ensure that transactions are properly authorized and recorded, assets are safeguarded against unauthorized use or disposition and liabilities are recognized. These controls include quality standards in hiring and training of employees, formalized policies and procedures, a corporate code of conduct and associated compliance program designed to establish and monitor conflicts of interest, the integrity of accounting records and financial information among others, and employee and management accountability for performance within appropriate and well-defined areas of responsibility.

The system of internal controls is further supported by the professional staff of an internal audit function who conduct periodic audits of all aspects of the company's operations.

The company retains independent petroleum consultants, Gilbert Laustsen Jung Associates Ltd., to conduct independent evaluations of the company's oil and gas reserves.

The Audit Committee of the Board of Directors, currently composed of five independent directors, reviews the effectiveness of the company's financial reporting systems, management information systems, internal control systems and internal auditors. It recommends to the Board of Directors the external auditors to be appointed by the shareholders at each annual meeting and reviews the independence and effectiveness of their work. In addition, it reviews with management and the external auditors any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of management that may be material for financial reporting purposes. The Audit Committee appoints the independent petroleum consultants. The Audit Committee meets at least quarterly to review and approve interim financial statements prior to their release, as well as annually to review Suncor's annual financial statements and Management's Discussion and Analysis, Annual Information Form/Form 40-F, and annual reserves estimates, and recommend their approval to the Board of Directors. The internal auditors and PricewaterhouseCoopers LLP have unrestricted access to the company, the Audit Committee and the Board of Directors.

/s/ Richard L. George	/s/ J. Kenneth Alley
Richard L. George	**J. Kenneth Alley**
President and	Senior Vice President and
Chief Executive Officer	Chief Financial Officer

February 23, 2005

The following report is provided by management in respect of the company's internal control over financial reporting (as defined in Rule 13a-15(f) under the U.S. Securities Exchange Act of 1934):

management's report on internal control over financial reporting

1. Management is responsible for establishing and maintaining adequate internal control over the company's financial reporting.

2. Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control – Integrated Framework to evaluate the effectiveness of the company's internal control over financial reporting.

3. Management has assessed the effectiveness of the company's internal control over financial reporting as at December 31, 2004, and has concluded that such internal control over financial reporting was effective as at that date. Additionally, based on our assessment, we determined that there were no material weaknesses in internal control over financial reporting as of December 31, 2004.

4. PricewaterhouseCoopers LLP, who has audited the company's consolidated financial statements for the year ended December 31, 2004, has also audited management's assessment of the effectiveness of the company's internal control over financial reporting as at December 31, 2004 as stated in their report which appears herein.

/s/ Richard L. George	/s/ J. Kenneth Alley
Richard L. George	**J. Kenneth Alley**

President and
Chief Executive Officer

Senior Vice President and
Chief Financial Officer

February 23, 2005

auditors' report

TO THE SHAREHOLDERS OF SUNCOR ENERGY INC.

We have audited the accompanying Consolidated Balance Sheets of Suncor Energy Inc. (the company) as at December 31, 2004 and 2003 and the related Consolidated Statements of Earnings, Cash Flows and Changes in Shareholders' Equity for each of the years in the three-year period ended December 31, 2004. We have also audited the effectiveness of the company's internal control over financial reporting as at December 31, 2004, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") and management's assessment thereof included in the accompanying Management's Report on Internal Control over Financial Reporting. The company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on these financial statements, an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audits.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

We conducted our audits of the company's financial statements in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We conducted our audit of the effectiveness of the company's internal control over financial reporting and management's assessment thereof in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles. Also, in our opinion, management's assessment that the company maintained effective internal control over financial reporting as at December 31, 2004 is fairly stated, in all material respects, based on criteria established in Internal Control – Integrated Framework issued by the COSO. Furthermore, in our opinion, the company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2004 based on criteria established in Internal Control – Integrated Framework issued by the COSO.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

February 23, 2005

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 February 23, 2005 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.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta, Canada

February 23, 2005

summary of significant accounting policies

Suncor Energy Inc. is a Canadian integrated energy company comprised of four operating segments: Oil Sands, Natural Gas, Energy Marketing and Refining – Canada, and Refining and Marketing – U.S.A.

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

Refining and Marketing – U.S.A. includes the manufacture, transportation and marketing of petroleum products, primarily in Colorado.

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 generally accepted accounting principles (GAAP) in Canada, 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.

Certain prior period comparative figures have also been reclassified to conform to the current period presentation.

(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 and up 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 – Canada and Refining and Marketing – U.S.A.) 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. Revenues associated with multi-element arrangements are recognized on a straight-line basis over the term of associated services.

(d) Property, Plant and Equipment and Intangible Assets

Cost

Property, plant and equipment and intangible assets are recorded at cost.

Expenditures to acquire and develop Oil Sands mining properties 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 natural gas and in-situ oil sands 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 a specific well does not contain proved reserves, the related 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 below.

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 after 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 their intended productive use.

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. The average projected holding period of five years is 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.

DOWNSTREAM OPERATIONS (INCLUDING ENERGY MARKETING AND REFINING – CANADA AND REFINING AND MARKETING – U.S.A.) Depreciation of property, plant and equipment is provided on a straight-line basis over the useful lives of assets. The Sarnia and Denver refineries and additions thereto are depreciated over an average of 30 years, service stations and related equipment over an average of 20 years and pipeline facilities and other equipment over three to 40 years. Intangible assets with determinable useful lives are amortized over a maximum period of four years. The amortization of intangible assets is included within depreciation expense in the Consolidated Statements of Earnings.

Asset Retirement Obligations

On January 1, 2004, the company retroactively adopted the new Canadian accounting standard related to “Asset Retirement Obligations” (ARO). Under the new standard, a liability is recognized for the future retirement obligations associated with the company’s property, plant and equipment. The fair value of the ARO is recorded on a discounted basis. This amount is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the company settles the obligation.

Impairment

Property, plant and equipment, including capitalized asset retirement costs are reviewed for impairment whenever events or conditions indicate that their net carrying amount, less 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 asset's fair value 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 a subsequently surrendered or abandoned unproved property 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

Deferred charges and other are primarily comprised of deferred overburden removal costs, deferred maintenance shutdown costs and deferred financing costs.

Overburden removal may precede mining of the oil sands deposit by as much as two years. Accordingly, 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 4), 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 stripping ratios based on a life-of-mine approach 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. Amortization of deferred overburden removal cost 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.

Financing costs related to the issuance of long-term debt are amortized over the term of the related debt.

(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 on a year-end market rate of interest for high quality debt instruments with cash flows that match the timing and amount of expected benefit payments. 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.

Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location.

(h) Derivative Financial Instruments

The company periodically enters into derivative financial instrument commodity contracts such as forwards, futures, swaps and options to hedge against the potential adverse impact of changing market prices due to changes in the underlying commodity indices. 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.

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 believes that its hedging documentation and tests of effectiveness are prepared in accordance with the provisions of AcG-13.

The company also uses energy derivatives, including physical and financial swaps, forwards and options, to gain market information and to earn trading revenues. These energy marketing and trading activities are accounted for at fair value.

(i) Foreign Currency Translation

Monetary assets and liabilities denominated 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, 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.

The company's Refining and Marketing – U.S.A. operations are classified as self-sustaining and are translated into Canadian dollars using the current rate method. Assets and liabilities are translated at the period end exchange rate, while revenues and expenses are translated using average exchange rates during the period. Translation gains or losses are included in cumulative foreign exchange adjustments in the Consolidated Statements of Changes in Shareholders' Equity.

(j) Stock-based Compensation Plans

Under the company's common share option programs (see note 13), common share options are granted to executives, employees and non-employee directors.

Compensation expense is recorded in the Consolidated Statements of Earnings as operating, selling and general expense for all common share options granted to employees and non-employee directors on or after January 1, 2003, with a corresponding increase recorded as contributed surplus in the Consolidated Statements of Changes in Shareholders' Equity. The expense is based on the fair values of the option at the time of grant and is recognized in the Consolidated Statements of Earnings over the estimated vesting periods of the respective options. For common share options granted prior to January 1, 2003 ("pre-2003 options"), compensation expense is not recognized in the Consolidated Statement of Earnings. The company continues to disclose the pro forma earnings impact of related stock-based compensation expense for pre-2003 options. Consideration paid to the company on exercise of 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) Transportation Costs

Transportation costs billed to customers are classified as revenues with the related transportation costs classified as transportation and other costs in the Consolidated Statements of Earnings.

(l) Recently Issued Canadian Accounting Standards

Variable Interest Entities

In 2003, Canadian Accounting Guideline 15 (AcG 15), "Consolidation of Variable Interest Entities" (VIEs), was issued. Effective January 1, 2005, AcG 15 requires consolidation of a VIE where the company will absorb a majority of a VIE's losses, receive a majority of its returns, or both. The company will be required to consolidate the VIE related to the sale of equipment as described in note 11(c). The company does not expect a significant impact on net earnings upon consolidation of the equipment VIE. The impact on the balance sheet will be an increase to property, plant and equipment of $14 million, an increase to inventory of $8 million, and an increase to long-term debt of $22 million. The company's accounts receivable securitization program described in note 11(c), as currently structured, does not meet the AcG 15 criteria for consolidation by Suncor.

Liabilities and Equity

In 2003, the Canadian Accounting Standards Board approved an amendment to its Handbook Section 3860 "Financial Instruments – Disclosure and Presentation" requiring certain obligations that must or could be settled with an entity's own equity instruments to be presented as liabilities. The amendment, effective for the company's 2005 fiscal year and applied on a retroactive basis, will affect the company's current presentation of preferred securities as equity (see note 12). The reclassification of the preferred securities from equity to long-term debt is expected to increase property, plant and equipment by $37 million, and increase depreciation, depletion and amortization by $1 million.

consolidated statements of earnings

For the years ended December 31 ($ millions)	2004	2003	2002
Revenues			
Operating revenues (notes 7, 17 and 18)	**8 226**	6 289	4 883
Energy marketing and trading activities (note 7c)	**392**	276	147
Interest	**3**	6	2
	8 621	6 571	5 032

Expenses			
Purchases of crude oil and products	**2 867**	1 686	1 156
Operating, selling and general	**1 769**	1 478	1 274
Energy marketing and trading activities (note 7)	**373**	279	142
Transportation and other costs	**132**	135	128
Depreciation, depletion and amortization	**717**	618	595
Accretion of asset retirement obligations	**26**	25	25
Exploration (note 18)	**55**	51	26
Royalties (note 5)	**531**	139	98
Taxes other than income taxes (note 18)	**496**	426	374
(Gain) on disposal of assets	**(16)**	(17)	(2)
(Gain) on sale of retail natural gas marketing business (note 18)	**—**	—	(38)
Project start-up costs	**26**	16	3
Financing expenses (income) (note 15)	**9**	(66)	124
	6 985	4 770	3 905
Earnings Before Income Taxes	**1 636**	1 801	1 127
Provision for income taxes (note 10)			
Current	**69**	38	74
Future	**467**	688	304
	536	726	378
Net Earnings	**1 100**	1 075	749
Dividends on preferred securities, net of tax (note 12)	**(6)**	(27)	(28)
Revaluation of US$ preferred securities, net of tax	**(6)**	37	1
Net earnings attributable to common shareholders	**1 088**	1 085	722
Per Common Share (dollars) (note 14)			
Net earnings attributable to common shareholders			
Basic	**2.40**	2.41	1.61
Diluted	**2.36**	2.24	1.58
Cash dividends	**0.23**	0.1925	0.17

See accompanying Summary of Significant Accounting Policies and Notes.

consolidated balance sheets

As at December 31 ($ millions)	2004	2003
Assets		
Current assets		
Cash and cash equivalents	**88**	388
Accounts receivable (notes 11c and 18)	**627**	505
Inventories (note 16)	**423**	371
Future income taxes (note 10)	**57**	15
Total current assets	**1 195**	1 279
Property, plant and equipment, net (note 3)	**10 289**	8 936
Deferred charges and other (note 4)	**320**	286
Total assets	**11 804**	10 501
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt	**30**	31
Accounts payable and accrued liabilities (notes 8 and 9)	**1 306**	970
Income taxes payable	**32**	9
Taxes other than income taxes	**41**	49
Future income taxes (note 10)	**—**	1
Total current liabilities	**1 409**	1 060
Long-term debt (note 6)	**2 217**	2 448
Accrued liabilities and other (notes 8 and 9)	**749**	616
Future income taxes (note 10)	**2 532**	2 022
Total liabilities	**6 907**	6 146
Commitments and contingencies (note 11)		
Shareholders' equity		
Preferred securities (note 12)	**—**	476
Share capital (note 13)	**651**	604
Contributed surplus (note 13)	**32**	7
Cumulative foreign currency translation	**(55)**	(26)
Retained earnings	**4 269**	3 294
Total shareholders' equity	**4 897**	4 355

Total liabilities and shareholders' equity	**11 804**	10 501

See accompanying Summary of Significant Accounting Policies and Notes.

Approved on behalf of the Board of Directors:

/s/ Richard L. George	/s/ John T. Ferguson
Richard L. George	**John T. Ferguson**
Director	Director

February 23, 2005

consolidated statements of cash flows

For the years ended December 31 ($ millions)	2004	2003	2002
Operating Activities			
Cash flow from operations (a)	**2 021**	2 079	1 440
Decrease (increase) in operating working capital (net of effects of acquisition of Denver refinery and related assets)			
Accounts receivable	**(121)**	(105)	(97)
Inventories	**(51)**	(19)	(8)
Accounts payable and accrued liabilities	**337**	258	44
Taxes payable	**16**	5	77
Cash flow from operating activities	**2 202**	2 218	1 456
Cash Used in Investing Activities (a)	**(1 824)**	(1 702)	(861)
Net Cash Surplus Before Financing Activities	**378**	516	595
Financing Activities			
Increase (decrease) in short-term debt	**(1)**	31	(31)
Proceeds from issuance of long-term debt	**—**	651	797
Net decrease in other long-term debt	**(142)**	(716)	(1 245)
Redemption of preferred securities (note 12)	**(493)**	—	—
Issuance of common shares under stock option plans	**41**	20	19
Dividends paid on preferred securities	**(9)**	(45)	(48)
Dividends paid on common shares	**(97)**	(81)	(73)
Deferred revenue	**26**	—	—
Cash flow used in financing activities	**(675)**	(140)	(581)
Increase (Decrease) in Cash and Cash Equivalents	**(297)**	376	14
Effect of Foreign Exchange on Cash and Cash Equivalents	**(3)**	(3)	—
Cash and Cash Equivalents at Beginning of Year	**388**	15	1
Cash and Cash Equivalents at End of Year	**88**	388	15

(a) See Schedules of Segmented Data on pages 68 and 69.

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	Contributed Surplus	Cumulative Foreign Currency Translation	Retained Earnings
At December 31, 2001, as previously reported	525	555	—	—	1 700
Retroactive adjustment for change in accounting policy, net of tax (note 1)	—	—	—	—	(49)
At December 31, 2001, as restated	525	555	—	—	1 651
Net earnings	—	—	—	—	749
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	(2)	—	—	—	1
At December 31, 2002, as restated	523	578	—	—	2 296

Net earnings	—	—	—	—	1 075
Dividends paid on preferred securities, net of tax	—	—	—	—	(27)
Dividends paid on common shares	—	—	—	—	(81)
Issued for cash under stock option plans	—	2 0	—	—	—
Issued under dividend reinvestment plan	—	6	—	—	(6)
Stock-based compensation expense	—	—	7	—	—
Foreign currency translation adjustment	—	—	—	(26)	—
Revaluation of US$ preferred securities	(47)	—	—	—	37
At December 31, 2003, as restated	**476**	**604**	**7**	**(26)**	**3 294**
Net earnings	**—**	**—**	**—**	**—**	**1 100**
Dividends paid on preferred securities, net of tax	**—**	**—**	**—**	**—**	**(6)**
Dividends paid on common shares	**—**	**—**	**—**	**—**	**(97)**
Issued for cash under stock option plans	**—**	**41**	**—**	**—**	**—**
Issued under dividend reinvestment plan	**—**	**6**	**—**	**—**	**(6)**
Stock-based compensation expense	**—**	**—**	**25**	**—**	**—**
Foreign currency translation adjustment	**—**	**—**	**—**	**(29)**	**—**
Revaluation of US$ preferred securities	**7**	**—**	**—**	**—**	**(6)**
Reclassification of issue costs for preferred securities	**10**	**—**	**—**	**—**	**(10)**
Redemption of preferred securities (note 12)	**(493)**	**—**	**—**	**—**	**—**
At December 31, 2004	**—**	**651**	**32**	**(55)**	**4 269**

See accompanying Summary of Significant Accounting Policies and Notes.

schedules of segmented data (a)

	Oil Sands			Natural Gas			Energy Marketing and Refining – Canada		
For the years ended December 31 ($ millions)	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
EARNINGS									
Revenues (b)									
Operating revenues	**3 171**	2 676	2 241	**499**	436	279	**3 060**	2 660	2 361
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**400**	276	147
Intersegment revenues (c)	**425**	385	375	**68**	76	60	**—**	—	—
Interest	**—**	—	—	**—**	—	—	**—**	—	—
	3 596	3 061	2 616	**567**	512	339	**3 460**	2 936	2 508
Expenses									
Purchases of crude oil and products	**75**	12	7	**—**	—	16	**2 115**	1 797	1 564
Operating, selling and general	**939**	865	790	**100**	73	67	**418**	359	352
Energy marketing and trading activities	**—**	—	—	**—**	—	—	**381**	279	142
Transportation and other costs	**88**	101	104	**21**	24	24	**3**	3	—
Depreciation, depletion and amortization	**503**	458	458	**115**	91	75	**69**	59	60
Accretion of asset retirement obligations	**21**	21	19	**4**	3	4	**1**	1	2
Exploration	**17**	11	9	**38**	40	17	**—**	—	—
Royalties (note 5)	**407**	33	33	**124**	106	65	**—**	—	—
Taxes other than income taxes	**28**	24	23	**2**	3	2	**352**	342	348
(Gain) loss on disposal of assets	**4**	(1)	2	**(19)**	(12)	(4)	**(2)**	(4)	—
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**—**	—	—	**—**	—	(38)
Project start-up costs	**26**	10	3	**—**	—	—	**—**	—	—
Financing expenses (income)	**—**	—	—	**—**	—	—	**—**	—	—
	2 108	1 534	1 448	**385**	328	266	**3 337**	2 836	2 430
Earnings (loss) before income taxes	**1 488**	1 527	1 168	**182**	184	73	**123**	100	78
Provision for income taxes	**(493)**	(639)	(386)	**(67)**	(64)	(39)	**(43)**	(47)	(17)
Net earnings (loss)	**995**	888	782	**115**	120	34	**80**	53	61
As at December 31									
TOTAL ASSETS	**9 032**	7 934	7 186	**965**	763	793	**1 321**	1 080	978

(a) Accounting policies for segments are the same as those described in the Summary of Significant Accounting Policies.
(b) There were no customers that represented 10% or more of the company's 2004 or 2003 consolidated revenues. (2002 – one customer represented 10% or more ($641 million)).
(c) Intersegment revenues are recorded at prevailing fair market prices and accounted for as if the sales were to third parties.

See accompanying Summary of Significant Accounting Policies and Notes.

For the years ended December 31 ($ millions)	Refining and Marketing U.S.A. 2004	2003	2002	Corporate and Eliminations 2004	2003	2002	Total 2004	2003	2002
EARNINGS									
Revenues (b)									
Operating revenues	**1 494**	515	—	**2**	2	2	**8 226**	6 289	4 883
Energy marketing and trading activities	**—**	—	—	**(8)**	—	—	**392**	276	147
Intersegment revenues (c)	**—**	—	—	**(493)**	(461)	(435)	**—**	—	—
Interest	**1**	—	—	**2**	6	2	**3**	6	2
	1 495	515	—	**(497)**	(453)	(431)	**8 621**	6 571	5 032
Expenses									
Purchases of crude oil and products	**1 171**	340	—	**(494)**	(463)	(431)	**2 867**	1 686	1 156
Operating, selling and general	**124**	68	—	**188**	113	65	**1 769**	1 478	1 274
Energy marketing and trading activities	**—**	—	—	**(8)**	—	—	**373**	279	142
Transportation and other costs	**20**	7	—	**—**	—	—	**132**	135	128
Depreciation, depletion and amortization	**22**	6	—	**8**	4	2	**717**	618	595
Accretion of asset retirement obligations	**—**	—	—	**—**	—	—	**26**	25	25
Exploration	**—**	—	—	**—**	—	—	**55**	51	26
Royalties (note 5)	**—**	—	—	**—**	—	—	**531**	139	98
Taxes other than income taxes	**114**	57	—	**—**	—	1	**496**	426	374
(Gain) loss on disposal of assets	**1**	—	—	**—**	—	—	**(16)**	(17)	(2)
(Gain) on sale of retail natural gas marketing business	**—**	—	—	**—**	—	—	**—**	—	(38)
Project start-up costs	**—**	6	—	**—**	—	—	**26**	16	3
Financing expenses (income)	**—**	—	—	**9**	(66)	124	**9**	(66)	124
	1 452	484	—	**(297)**	(412)	(239)	**6 985**	4 770	3 905
Earnings (loss) before income taxes	**43**	31	—	**(200)**	(41)	(192)	**1 636**	1 801	1 127
Provision for income taxes	**(9)**	(13)	—	**76**	37	64	**(536)**	(726)	(378)
Net earnings (loss)	**34**	18	—	**(124)**	(4)	(128)	**1 100**	1 075	749
As at December 31									
TOTAL ASSETS	**518**	442	—	**(32)**	282	54	**11 804**	10 501	9 011

schedules of segmented data (a) (continued)

For the years ended December 31 ($ millions)	Oil Sands 2004	2003	2002	Natural Gas 2004	2003	2002	Energy Marketing and Refining – Canada 2004	2003	2002
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash from (used in) operating activities:									
Cash flow from (used in) operations									
Net earnings (loss)	**995**	888	782	**115**	120	34	**80**	53	61
Exploration expenses	**—**	—	—	**38**	40	17	**—**	—	—
Non-cash items included in earnings									
Depreciation, depletion and amortization	**503**	458	458	**115**	91	75	**69**	59	60
Income taxes	**493**	639	386	**67**	64	39	**43**	47	17
(Gain) loss on disposal of assets	**4**	(1)	2	**(19)**	(12)	(4)	**(2)**	(4)	(38)
Stock-based compensation expense	**—**	—	—	**—**	—	—	**—**	—	—
Other	**(29)**	4	15	**4**	(5)	4	**(3)**	10	11
Overburden removal outlays	**(222)**	(175)	(160)	**—**	—	—	**—**	—	—
Increase (decrease) in deferred credits and other	**8**	(10)	(8)	**(1)**	—	(1)	**1**	(1)	1
Total cash flow from (used in) operations	**1 752**	1 803	1 475	**319**	298	164	**188**	164	112
Decrease (increase) in operating working capital (net of effects of acquisition of Denver refinery and related assets)	**71**	51	(116)	**(1)**	11	22	**50**	—	(15)
Total cash from (used in) operating activities	**1 823**	1 854	1 359	**318**	309	186	**238**	164	97
Cash from (used in) investing activities:									
Capital and exploration expenditures	**(1 118)**	(948)	(617)	**(279)**	(183)	(163)	**(228)**	(122)	(60)
Acquisition of Denver refinery and related assets	**—**	—	—	**—**	—	—	**—**	—	—
Deferred maintenance shutdown expenditures	**(4)**	(100)	(9)	**(1)**	—	—	**(20)**	(17)	(18)
Deferred outlays and other investments	**(9)**	(10)	(4)	**—**	—	—	**(14)**	(2)	(18)

Proceeds from disposals	**45**	3	—	**29**	17	5	**3**	6	62
Total cash (used in) investing activities	**(1 086)**	(1 055)	(630)	**(251)**	(166)	(158)	**(259)**	(135)	(34)
Net cash surplus (deficiency) before financing activities	**737**	799	729	**67**	143	28	**(21)**	29	63

(a) 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.

For the years ended December 31 ($ millions)	Refining and Marketing U.S.A. 2004	2003	2002	Corporate and Eliminations 2004	2003	2002	Total 2004	2003	2002
CASH FLOW BEFORE FINANCING ACTIVITIES									
Cash from (used in) operating activities:									
Cash flow from (used in) operations									
Net earnings (loss)	**34**	18	—	**(124)**	(4)	(128)	**1 100**	1 075	749
Exploration expenses	**—**	—	—	**—**	—	—	**38**	40	17
Non-cash items included in earnings									
Depreciation, depletion and amortization	**22**	6	—	**8**	4	2	**717**	618	595
Income taxes	**9**	13	—	**(145)**	(75)	(138)	**467**	688	304
(Gain) loss on disposal of assets	**1**	—	—	**—**	—	—	**(16)**	(17)	(40)
Stock-based compensation expense	**—**	—	—	**25**	7	—	**25**	7	—
Other	**(8)**	(2)	—	**(78)**	(163)	(3)	**(114)**	(156)	27
Overburden removal outlays	**—**	—	—	**—**	—	—	**(222)**	(175)	(160)
Increase (decrease) in deferred credits and other	**1**	(1)	—	**17**	11	(44)	**26**	(1)	(52)
Total cash flow from (used in) operations	**59**	34	—	**(297)**	(220)	(311)	**2 021**	2 079	1 440
Decrease (increase) in operating working capital (net of effects of acquisition of Denver refinery and related assets)	**68**	46	—	**(7)**	31	125	**181**	139	16
Total cash from (used in) operating activities	**127**	80	—	**(304)**	(189)	(186)	**2 202**	2 218	1 456
Cash from (used in) investing activities:									
Capital and exploration expenditures	**(190)**	(31)	—	**(31)**	(32)	(37)	**) (1 846**	) (1 316	(877)
Acquisition of Denver refinery and related assets	**—**	(272)	—	**—**	—	—	**—**	(272)	—
Deferred maintenance shutdown expenditures	**(7)**	—	—	**—**	—	—	**(32)**	(117)	(27)
Deferred outlays and other investments	**(1)**	3	—	**1**	(14)	(2)	**(23)**	(23)	(24)
Proceeds from disposals	**—**	—	—	**—**	—	—	**77**	26	67
Total cash (used in) investing activities	**(198)**	(300)	—	**(30)**	(46)	(39)	**(1 824)**	(1 702)	(861)
Net cash surplus (deficiency) before financing activities	**(71)**	(220)	—	**(334)**	(235)	(225)	**378**	516	595

notes to the consolidated financial statements

1. CHANGE IN ACCOUNTING POLICY

On January 1, 2004, the company retroactively adopted a new accounting policy for asset retirement obligations (see Summary of Significant Accounting Policies). The 2003 and estimated 2004 impact of adopting the new Canadian accounting standard compared to the previous standard is:

Change in Consolidated Balance Sheets

($ millions, increase/(decrease))	2004	2003
Property, plant and equipment	**284**	211
Future income tax assets	**33**	37
Total assets	**317**	248
Accounts payable and accrued liabilities	**—**	(2)
Accrued liabilities and other	**382**	320
Retained earnings	**(65)**	(70)

Total liabilities and shareholders' equity	**317**	248

Change in Consolidated Statements of Earnings

($ millions, increase/(decrease))	2004	2003	2002
Depreciation, depletion and amortization	**9**	7	10
Accretion of asset retirement obligations	**26**	25	25
Operating, selling and general expenses	**(43)**	(29)	(18)
Future income taxes	**3**	6	(5)
Net earnings	**5**	(9)	(12)
Per common share – basic (dollars)	**0.01**	(0.02)	(0.03)
Per common share – diluted (dollars)	**0.01**	(0.02)	(0.03)

See note 8 for a reconciliation of the beginning and ending aggregate carrying amount of the asset retirement obligation.

2. ACQUISITION OF REFINERY AND RELATED ASSETS

On August 1, 2003, the company acquired a Denver refinery, 43 retail stations and associated storage, pipeline and distribution facilities, and inventory from ConocoPhillips for cash consideration of $272 million. The purchase price was determined through a competitive bid process. The results of operations for these assets have been included in the consolidated financial statements from the date of acquisition.

The acquisition was accounted for by the purchase method of accounting. The allocation of fair value to the assets acquired and liabilities assumed was:

($ millions)	
Property, plant and equipment, and intangible assets	242
Inventory	88
Other assets	9
Total assets acquired	339
Liabilities assumed	(67)
Net assets acquired	272

Suncor recorded an environmental liability of $9 million at the acquisition date for the estimated costs of environmental clean-up work currently under way. A $9 million receivable was also recorded as ConocoPhillips agreed to indemnify Suncor for these costs. The recorded liability is part of an agreement between Suncor and ConocoPhillips whereby Suncor will be indemnified for any reclamation work identified prior to closing for a period up to 10 years from acquisition date, and up to $30 million. Additional costs ordered by a governmental agency are subject to indemnification from ConocoPhillips on a rolling 10-year limitation period from the date the contamination is discovered by Suncor. There is no time or dollar limit for any third-party claims against Suncor for which ConocoPhillips is liable.

Additionally, a $39 million liability was recorded at acquisition for environmental work required pursuant to a consent decree between ConocoPhillips, the Colorado Department of Public Health and the Environment and the United States Environmental Protection Agency.

For segmented reporting purposes, the results of the new Denver-based operations since the date of acquisition are reported in a new operating segment (Refining and Marketing – U.S.A.) in the accompanying Schedules of Segmented Data.

3. PROPERTY, PLANT AND EQUIPMENT

	2004		2003	
($ millions)	Cost	Accumulated Provision	Cost	Accumulated Provision
Oil Sands				
Plant	**5 156**	**929**	4 721	828
Mine and mobile equipment	**1 313**	**480**	1 267	426
In-situ properties	**1 267**	**26**	867	—
Pipeline	**101**	**48**	100	46
Capital leases	**29**	**25**	130	18
Major projects in progress	**1 486**	**—**	1 232	—
Asset retirement cost	**325**	**71**	267	63
	9 677	**1 579**	8 584	1 381
Natural Gas				
Proved properties	**1 396**	**653**	1 206	552
Unproved properties	**124**	**18**	114	38
Other support facilities and equipment	**18**	**13**	18	12
Asset retirement cost	**27**	**3**	4	2
	1 565	**687**	1 342	604
Energy Marketing and Refining – Canada				
Refinery	**875**	**468**	874	443

Marketing	**525**	**248**	494	239
Major projects in progress	**171**	**—**	—	—
Asset retirement cost	**11**	**5**	10	5
	1 582	**721**	1 378	687
Refining and Marketing – U.S.A.				
Refinery and intangible assets	**175**	**11**	165	2
Marketing	**38**	**2**	39	1
Pipeline	**25**	**1**	27	—
Major projects in progress	**128**	**—**	—	—
	366	**14**	231	3
Corporate	**118**	**18**	86	10
	13 308	**3 019**	11 621	2 685
Net property, plant and equipment		**10 289**		8 936

4. DEFERRED CHARGES AND OTHER

($ millions)	**2004**	**2003**
Oil Sands overburden removal costs (see below)	**67**	51
Deferred maintenance shutdown costs	**129**	137
Deferred financing costs	**25**	26
Other	**99**	72
Total deferred charges and other	**320**	286
Oil Sands overburden removal costs		
Balance – beginning of year	**51**	68
Outlays during the year	**222**	175
Depreciation on equipment during year	**19**	16
	292	259
Amortization during year	**(225)**	(208)
Balance – end of year	**67**	51

5. ROYALTIES

Crown royalties in effect for each Oil Sands project require payments to the Government of Alberta, based on annual gross revenues less related transportation costs (R) less allowable costs (C), including the deduction of certain capital expenditures (the 25% R-C royalty), subject to a minimum payment of 1% of R. During 2004, the Alberta government confirmed it would modify Suncor's royalty treatment because it does not recognize the company's Firebag in-situ facility as an expansion to the company's existing base mining and upgrading operations. Accordingly, for Alberta Crown royalty purposes, Suncor's Oil Sands operations are considered as two separate projects: Suncor's base Oil Sands mining and associated upgrading operations and Suncor's Firebag in-situ oil sands project. On the basis of this classification, Suncor provided for Alberta Crown royalty obligations of $407 million in 2004 (2003 and 2002 – $33 million).

In July 2004, Suncor issued a statement of claim against the Province of Alberta, seeking, among other things, to overturn the Crown's decision on the royalty treatment of Firebag. The Crown has issued a statement of defence. Should the company be successful in its claim, any recoveries would be recognized in the period they are realized.

6. LONG-TERM DEBT

($ millions)	**2004**	**2003**
Fixed-term debt, redeemable at the option of the company		
5.95% Notes, denominated in U.S. dollars, due in 2034 (a)	**602**	646
7.15% Notes, denominated in U.S. dollars, due in 2032	**602**	646
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, repaid in 2004	**—**	125
	2 104	2 317
Revolving-term debt, with interest at variable rates (see Credit Facilities)		
Commercial paper (interest at December 31, 2004 – 2.3%) (c)	**89**	—
Total unsecured long-term debt	**2 193**	2 317
Secured long-term debt with interest rates averaging 5.4% (2003 – 5.6%)	**5**	4
Capital leases (d), (e)	**19**	127
Total long-term debt	**2 217**	2 448

(a) In 2003, the company issued 5.95% Notes with a principal amount of US$500 million (Cdn$ equivalent of $651 million).

(b) The company has entered into various interest rate swap transactions that are outstanding at December 31, 2004. 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 Transaction	Principal Swapped ($ millions)	Swap Maturity	2004 Effective Interest Rate
Swap of 6.10% Medium Term Notes to floating rates	150	2007	3.6%
Swap of 6.80% Medium Term Notes to floating rates	250	2007	4.3%
Swap of 6.70% Medium Term Notes to floating rates	200	2011	3.5%

(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 facilities.

(d) Obligations under capital leases are as follows:

($ millions)	2004	2003
Energy services assets lease with interest at 6.82%, repaid in 2004	—	101
Other equipment leases with interest rates between prime plus 0.5% and 12.4% and maturity dates ranging from 2008 to 2029	**19**	26
	19	127

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

($ millions)	Capital Leases	Other Long-term Debt
2005	3	90
2006	3	1
2007	3	401
2008	3	—
2009	3	—
Later years	24	1 706
Total minimum payments	39	2 198
Less amount representing imputed interest	20	
Present value of obligation under capital leases	19	

Long-term Debt (per cent)	2004	2003
Variable rate	**31**	25
Fixed rate	**69**	75

Credit Facilities

At December 31, 2004, the company had available credit facilities of $1,730 million, of which $1,510 million was undrawn, as follows:

($ millions)	
Facility that is fully revolving for 364 days, has a term period of one year and expires in 2006	200
Facility that is fully revolving for a period of three years and expires in 2007	1 500
Facilities that can be terminated at any time at the option of the lenders	30
Total available credit facilities	1 730
Credit facilities supporting outstanding commercial paper and standby letters of credit	220
Total undrawn credit facilities	1 510

At December 31, 2004, the company had issued $131 million in letters of credit to various third parties.

7. 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 holder, 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 below 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, substantially all current liabilities (except for the current portions of income taxes payable, future income taxes and retirement obligations), 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.

The following table summarizes estimated fair value information about the company's financial instruments recognized in the Consolidated Balance Sheets at December 31:

	2004		2003	
($ millions)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Cash and cash equivalents	**88**	**88**	388	388
Accounts receivable	**627**	**627**	505	505
Current liabilities	**1 252**	**1 252**	976	976
Long-term debt				
Fixed-term	**2 104**	**2 339**	2 317	2 502
Revolving-term	**89**	**89**	—	—
Other	**5**	**5**	4	4
Capital leases	**19**	**19**	127	127

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 is also a party to certain derivative financial instruments that are not recognized in the Consolidated Balance Sheets, as follows:

Revenue and Margin Hedges

Suncor operates in a global industry where the market price of its petroleum and natural gas products is determined based on floating benchmark indices denominated in U.S. dollars. The company periodically enters into derivative financial instrument contracts such as forwards, futures, swaps and options to hedge against the potential adverse impact of changing market prices due to changes in the underlying indices. Specifically, the company manages crude sales price variability by entering into U.S. dollar West Texas Intermediate (WTI) derivative transactions. As at December 31, 2004, the company had hedged a portion of its forecasted Canadian dollar denominated cash flows subject to U.S. dollar WTI commodity price risk until

December 31, 2005. The company had not hedged any portion of the foreign exchange component of these forecasted cash flows. As a result of the company's decision to suspend its strategic crude oil hedging program, no strategic crude oil hedges were entered into in 2004.

At December 31, 2004, the company had also hedged a portion of its forecasted cash flows related to natural gas production and refinery operations.

The financial instrument 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:

Strategic Crude Oil Hedges

($ millions except for average price)	Quantity (bpd)	Average Price (a)	Revenue Hedged ($ millions)	Hedge Period
As at December 31, 2004				
Crude oil swaps	**36 000**	**23**	**364**(c)	**2005**
As at December 31, 2003				
Crude oil swaps	68 000	24	772(c)	2004
Costless collars	11 000	21 – 24	109 – 125(c)	2004
Crude oil swaps	36 000	23	390(c)	2005
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

Margin Hedges	Quantity (bpd)	Average Margin US$/bbl	Margin Hedged	Hedge Period
Refined product sale and crude purchase swaps				
As at December 31, 2004	**6 300**	7	**15**(c)	**2005**(d)
As at December 31, 2003	6 600	5	3(c)	2004(e)
As at December 31, 2002	20 700	5	9(c)	2003(f)

Natural Gas Hedges	Quantity (GJ/day)	Average Price Cdn$/GJ	Revenue Hedged	Hedge Period
Swaps and costless collars				
As at December 31, 2004				
Natural gas swaps	**4 000**	**7**	**10**	**2005**
Natural gas swaps	**4 000**	**7**	**10**	**2006**
Natural gas swaps	**4 000**	**6**	**9**	**2007**
Costless collars	**10 000**	**8 – 9**	**7 – 8**	**2005**(g)
As at December 31, 2003 (j)	30 000	6	16	2004(h)
As at December 31, 2002 (k)	25 000	4 – 6	9 – 14	2003(i)

(a) Average price for crude oil swaps is US$/barrel WTI at Cushing.
(b) For the period January to April 2003, inclusive. All other crude oil positions are for the full year.
(c) The revenue and margin hedged is translated to Cdn$ at the year-end exchange rate for convenience purposes.
(d) For the period January to September 2005.
(e) For the period January and February 2004.
(f) For the period January and February 2003.
(g) For the period January to March 2005.
(h) For the period January to March 2004.
(i) For the period January to March 2003.
(j) As of December 31, 2003, only swap hedges were outstanding.
(k) As of December 31, 2002, only costless collar hedges were outstanding.

Interest Rate Hedges

The company periodically enters into 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 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 swap contracts outstanding at December 31, 2004, are detailed in note 6, Long-term Debt.

Fair Value of Derivative Financial Instruments

The fair value of hedging derivative financial instruments is the estimated amount, based on broker quotes and/or internal valuation models, 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)	2004	2003
Revenue hedge swaps and collars	**(305)**	(285)
Margin hedge swaps	**5**	2

Interest rate and cross-currency interest rate swaps	**36**	32
	(264)	(251)

(c) Energy Marketing and Trading Activities

In addition to those financial derivatives used for hedging activities, the company also uses energy derivatives, including physical and financial swaps, forwards, futures and options to gain market information and earn trading revenues. These energy trading activities are accounted for using the mark-to-market method and, as such, physical and financial energy contracts are recorded at fair value at each balance sheet date. During 2004 Suncor recorded a net pretax gain of $11 million (2003 – pretax loss of $3 million; 2002 – $nil) related to the settlement and revaluation of financial energy trading contracts. In 2004 the settlement of physical trading activities also resulted in a net pretax gain of $12 million (2003 – $2 million; 2002 – $6 million). These gains were included as energy trading and marketing activities in the Consolidated Statement of Earnings. The above amounts do not include the impact of related general and administrative costs.

The fair value of unsettled financial energy trading assets and liabilities at December 31 were as follows:

($ millions)	2004	2003
Energy trading assets	**26**	5
Energy trading liabilities	**9**	5

The source of the valuations of the above contracts was based on actively quoted prices and internal valuation models.

(d) 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 with counterparties, of which substantially all are investment grade. Risk is also minimized through regular management review of credit ratings and potential exposure to such counterparties. At December 31, the company had exposure to credit risk with counterparties as follows:

($ millions)	2004	2003
Derivative contracts not accounted for as hedges	**7**	30
Unrecognized derivative contracts	**21**	27
	28	57

8. ACCRUED LIABILITIES AND OTHER

($ millions)	2004	2003
Asset retirement obligations (a)	**429**	363
Employee future benefits liability (see note 9)	**183**	181
Employee and director incentive plans	**50**	35
Deferred revenue	**64**	—
Environmental remediation costs (b)	**8**	34
Other	**15**	3
Total	**749**	616

(a) Asset Retirement Obligations

The asset retirement obligation also includes $47 million in current liabilities (2003 – $38 million). The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the long-term obligations associated with the retirement of property, plant and equipment.

($ millions)	2004	2003
Asset retirement obligations, beginning of year	**401**	400
Liabilities incurred	**82**	—
Liabilities settled	**(33)**	(24)
Accretion of asset retirement obligations	**26**	25
Asset retirement obligations, end of period	**476**	401

The total undiscounted amount of estimated cash flows required to settle the obligations at December 31, 2004, was approximately $1.1 billion (2003 – $1.0 billion), and has been discounted using a credit-adjusted risk-free rate of 6% (2003 – 6.5%). Payments to settle the ARO occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 35 years.

A significant portion of the company's assets have retirement obligations for which the fair value cannot be reasonably determined because the assets currently have an indeterminate life. The asset retirement obligation for these assets will be recorded in the first period in which the lives of the assets are determinable.

(b) Environmental Remediation Costs

Total accrued environmental remediation costs also include $35 million in current liabilities (2003 – $20 million).

9. EMPLOYEE FUTURE BENEFITS LIABILITY

Suncor employees are eligible to receive certain pension, health care and insurance benefits when they retire. The related ***Benefit Obligation*** *or commitment that Suncor has to employees and retirees at December 31, 2004, was $752 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 2004, ***Plan Assets*** *to meet the* ***Benefit Obligation*** *were $399 million.*

The excess of the ***Benefit Obligation*** *over* ***Plan Assets*** *of $353 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 non-indexed pension benefits at retirement based on years of service and final average earnings. These obligations are met through funded registered retirement plans and through unfunded, unregistered supplementary benefits that are paid directly to recipients. Company contributions to the funded plans are deposited with independent trustees who act as custodians of the funded pension plans' assets, as well as the disbursing agents of the benefits to recipients. Plan assets are managed by a pension committee on behalf of beneficiaries. The committee retains independent managers and advisors.

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, depending on funding status, and every year in the United States. The most recent valuation for the Canadian and U.S. plans was performed in 2004.

The company's other post-retirement benefits programs, which are unfunded, include certain health care and life insurance benefits provided to retired employees and eligible surviving dependants.

The expense and obligations for both funded and unfunded benefits are determined in accordance with Canadian GAAP and actuarial principles. 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 and Funded Status

The following table presents information about obligations recognized in the Consolidated Balance Sheets and the funded status of the plans at December 31:

	Pension Benefits		Other Post-retirement Benefits	
($ millions)	**2004**	**2003**	**2004**	**2003**
Change in benefit obligation				
Benefit obligation at beginning of year	**568**	489	**117**	97
Service costs	**25**	18	**5**	3
Interest costs	**34**	32	**7**	6
Plan participants' contributions	**3**	3	**—**	—
Acquisition (a)	**—**	14	**—**	6
Foreign exchange	**(2)**	(1)	**(1)**	—
Actuarial loss	**21**	37	**4**	8
Benefits paid	**(25)**	(24)	**(4)**	(3)
Benefit obligation at end of year (b), (f)	**624**	568	**128**	117
Change in plan assets (c)				
Fair value of plan assets at beginning of year	**336**	273	**—**	—
Actual return on plan assets	**33**	45	**—**	—
Employer contributions	**49**	36	**—**	—
Plan participants' contributions	**3**	3	—	**—**
Benefits paid	**(22)**	(21)	**—**	—
Fair value of plan assets at end of year (f)	**399**	336	**—**	—
Net unfunded obligation	**(225)**	(232)	**(128)**	(117)
Items not yet recognized in earnings:				
Unamortized net actuarial loss (d)	**125**	133	**49**	50
Unamortized past service costs (e)	**—**	—	**(29)**	(31)
Accrued benefit liability	**(100)**	(99)	**(108)**	(98)
Current liability	**(40)**	(14)	**(3)**	(2)
Long-term liability	**(78)**	(85)	**(105)**	(96)
Long-term asset	**18**	—	**—**	—
Total accrued benefit liability	**(100)**	(99)	**(108)**	(98)

(a) In 2003, in connection with the acquisition of the Denver refinery and related assets from ConocoPhillips, the company assumed a pension benefit obligation of $14 million and other post-retirement benefit obligations of $6 million. No pension plan assets were acquired.
(b) Obligations are based on the following assumptions:

	Pension Benefit Obligations		Other Post-retirement Benefits Obligation	
(per cent)	2004	2003	2004	2003
Discount rate	**5.75**	6.00	**5.75**	6.00
Rate of compensation increase	**4.50**	4.00	**4.25**	4.00

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

	Rate of Return on Plan Assets		Discount Rate		Rate of Compensation Increase	
($ millions)	1% increase	1% decrease	1% increase	1% decrease	1% increase	1% decrease
Increase (decrease) to net periodic benefit cost	(4)	4	(11)	12	6	(5)
Increase (decrease) to benefit obligation	—	—	(99)	115	30	(27)

In order to measure the expected cost of other post-retirement benefits, an 11.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2004 (2003 – 12%; 2002 – 9%). It is assumed that this rate will decrease by 0.5% annually, 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 one per cent change in assumed health care cost trend rates would have the following effects:

($ millions)	1% increase	1% decrease
Increase (decrease) to total of service and interest cost components of net periodic post-retirement health care benefit cost	2	(1)
Increase (decrease) to the health care component of the accumulated Post-retirement benefit obligation	13	(11)

(c) Pension plan assets are not the company's assets and therefore are not included in the Consolidated Balance Sheets.
(d) 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 12 years for pension benefits (2003 – 12 years; 2002 – 13 years), and over the expected average future service life to full eligibility age of 12 years for other post-retirement benefits (2003 and 2002 – 12 years).
(e) Effective April 1, 2003, the company implemented amendments to its post-retirement benefits program to manage its exposures to future health care and life insurance costs. Certain of the company's employees will continue to receive post-retirement benefits under the old plan provisions. These plan amendments reduced the company's other post-retirement benefits obligation at December 31, 2002, by $34 million.
(f) The company uses a measurement date of December 31 to value the plan assets and accrued benefit obligation.

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

	Pension Benefits		Other Post-retirement Benefits	
($ millions)	2004	2003	2004	2003
Funded plans	**537**	498	**—**	—
Unfunded plans	**87**	70	**128**	117
Benefit obligation at end of year	**624**	568	**128**	117

Components of Net Periodic Benefit Cost (a)

	Pension Benefits			Other Post-retirement Benefits		
($ millions)	2004	2003	2002	2004	2003	2002
Current service costs	**25**	18	17	**5**	3	4
Interest costs	**34**	32	30	**7**	6	6
Expected return on plan assets (b)	**(25)**	(20)	(22)	—	—	—
Amortization of net actuarial loss	**19**	22	15	**1**	1	2
Net periodic benefit cost recognized (c)	**53**	52	40	**13**	10	12

Components of Net Incurred Benefit Cost (a)

	Pension Benefits			Other Post-retirement Benefits		
($ millions)	2004	2003	2002	2004	2003	2002
Current service costs	**25**	18	17	**5**	3	4
Interest costs	**34**	32	30	**7**	6	6
Actual (return) loss on plan assets	**(33)**	(45)	24	**—**	—	—

Amendments	**—**	—	—	**—**	—	(34)
Actuarial (gain) loss	**21**	37	(1)	**4**	8	30
Net incurred benefit cost	**47**	42	70	**16**	17	6

(a) The net periodic benefit cost includes certain accounting adjustments made to allocate costs to the periods in which employee services are rendered, consistent with the long-term nature of the benefits. Costs actually incurred in the period (arising from actual returns on plan assets and actuarial gains and losses in the period) differ from allocated costs recognized.

(b) The expected return on plan assets is the expected long-term rate of return on plan assets for the year. It is 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 12 years for pension benefits.
To estimate the expected long-term rate of return on plan assets, the company considered the current level of expected returns on the fixed income portion of the portfolio, the historical level of the risk premium associated with other asset classes in which the portfolio is invested and the expectation for future returns on each asset class. The expected return for each asset class was weighted based on the policy asset mix to develop an expected long-term rate of return on asset assumption for the portfolio.

(c) Pension expense is based on the following assumptions:

	Pension Benefit Expense			Other Post-retirement Benefits Expense		
(per cent)	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
Discount rate	**6.00**	6.50	6.50	**6.00**	6.50	6.50
Expected return on plan assets	**7.00**	7.25	7.25	**—**	—	—
Rate of compensation increase	**4.00**	4.00	4.25	**4.00**	4.00	4.25

Plan Assets and Investment Objectives

The company's long-term investment objective is to secure the defined pension benefits while managing the variability and level of its contributions. The portfolio is rebalanced periodically as required, while ensuring that the maximum equity content is 65% at any time. Plan assets are managed by external managers, who report to a Pension Committee, and are restricted to those permitted by applicable legislation. Investments are made through pooled, mutual or segregated funds.

The company's pension plan asset allocation based on market values as at December 31, 2004 and 2003, and the target allocation for 2005 is as follows:

	Target Allocation %	Percentage of Plan Assets	
	2005	**2004**	**2003**
Asset Category			
Equities	60	**60**	61
Fixed income	40	**40**	39
Total	100	**100**	100

Equity securities do not include any direct investments in Suncor shares.

Cash Flows

The company expects that contributions to its pension plans in 2005 will be $65 million, including approximately $15 million for the company's senior executive and supplemental retirement plans. Expected benefit payments from the plans are as follows:

	Pension Benefits	Other Post-retirement Benefits
2005	27	4
2006	29	5
2007	31	5
2008	33	6
2009	34	7
2010 – 2014	211	49
Total	365	76

Defined Contribution Pension Plan

The company has a Canadian defined contribution plan and a U.S. 401(k) savings plan, under which both the company and employees make contributions. Company contributions and corresponding expense totalled $8 million in 2004 (2003 – $6 million; 2002 – $5 million).

10. INCOME TAXES

The assets and liabilities shown on Suncor's balance sheets are calculated in accordance with Canadian GAAP. 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 next page 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:

	2004		2003		2002	
($ millions)	**Amount**	**%**	**Amount**	**%**	**Amount**	**%**
Federal tax rate	**589**	**36**	666	37	428	38
Provincial abatement	**(164)**	**(10)**	(180)	(10)	(113)	(10)
Federal surtax	**18**	**1**	20	1	13	1
Provincial tax rates	**192**	**12**	225	13	148	13
Statutory tax and rate	**635**	**39**	731	41	476	42
Adjustment of statutory rate for future rate reductions	**(86)**	**(5)**	(92)	(6)	—	—
	549	**34**	639	35	476	42
Add (deduct) the tax effect of:						
Crown royalties	**133**	**8**	50	3	39	3
Resource allowance	**(69)**	**(4)**	(31)	(2)	(34)	(3)
Temporary difference in resource allowance	**—**	**—**	—	—	(117)	(10)
Large corporations tax	**18**	**1**	19	1	17	1
Tax rate changes on opening future income taxes	**(53)**	**(3)**	89	5	(10)	(1)
Attributed Canadian royalty income	**(29)**	**(2)**	(8)	—	(2)	—
Stock-based compensation	**8**	**—**	3	—	—	—
Assessments and adjustments	**—**	**—**	—	—	10	1
Capital gains	**(18)**	**(1)**	(34)	(2)	—	—
Other	**(3)**	**—**	(1)	—	(1)	—
Income taxes and effective rate	**536**	**33**	726	40	378	33

In 2004 net income tax payments totalled $50 million (2003 – $45 million payment; 2002 – $8 million refund).

The resource allowance is a federal tax deduction allowed as a proxy for non-deductible provincial Crown royalties. As required by Canadian GAAP, resource allowance is accounted for by adjusting the statutory tax rate by the resource allowance rate.

Effective January 1, 2003, the Canadian government enacted changes to the federal taxation policies relating to the resource sector. The changes are to be fully phased in by 2007 and include a 7% reduction of the federal rate, deductibility of provincial Crown royalties and the elimination of the federal resource allowance deduction. In 2004 and 2003, the company's future income tax liabilities related to its resource operations were based on the future tax rates with the full 7% federal tax rate reduction.

Effective April 1, 2004, the Alberta provincial corporate tax rate decreased by 1% (2003 – decrease of 1%). In 2003 the Ontario government substantively enacted a general corporate tax rate and manufacturing and processing tax rate increase of 1.5% and 1% respectively, effective January 1, 2004.

Accordingly, in 2004, the company revalued its future income tax liabilities and recognized a decrease in future income tax expense of $53 million (2003 – increase of $89 million).

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

	2004		2003	
($ millions)	**Current**	**Non-current**	**Current**	**Non-current**
Future income tax assets:				
Employee future benefits	**14**	**—**	4	—
Asset retirement obligations	**16**	**—**	9	—
Inventories	**27**	**—**	2	—
	57	**—**	15	—
Future income tax liabilities:				
Depreciation	**—**	**2 734**	—	2 095
Overburden removal costs	**—**	**20**	—	16
Deferred maintenance shutdown costs	**—**	**44**	—	41
Inventories	**—**	**—**	(12)	—
Employee future benefits	**—**	**(77)**	—	(70)
Asset retirement obligations	**—**	**(139)**	—	(7)
Attributed Canadian royalty income	**—**	**(69)**	—	(47)
Other	**—**	**19**	13	(6)
	—	**2 532**	1	2 022

11. COMMITMENTS, CONTINGENCIES, GUARANTEES AND SUBSEQUENT EVENT

(a) Operating Commitments

In order to ensure continued availability of, and access to, facilities and services to meet its operational requirements, the company periodically 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, 2004, future minimum amounts payable under these leases and agreements are as follows:

($ millions)	Pipeline Capacity and Energy Services (1)	Operating Leases
2005	178	44
2006	190	31
2007	190	27
2008	210	22
2009	211	15
Later years	3 626	54
	4 605	193

(1) 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 are 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 third-party energy company. Since October 1999, this third-party 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 recognition of estimated asset retirement obligations. Effective January 1, 2004, the company adopted new Canadian accounting standards that required recognition of a liability for the future retirement obligations associated with the company's property, plant and equipment (see Summary of Significant Accounting Policies and Note 1). Estimates of retirement obligation costs can change significantly based on such factors as operating experience, changes in legislation and regulations and cost.

The company carries property loss and business interruption insurance policies with a combined coverage limit of up to US$1,150 million, net of deductible amounts. The primary property loss policy of US$250 million has a deductible of US$10 million per incident and the primary business interruption policy of US$200 million has a deductible per incident of the greater of US$50 million gross earnings lost (as defined in the insurance policy) or 30 days from the incident. In addition to these primary coverage insurance policies, Suncor has excess coverage of US$700 million that can be used for either property loss or business interruption coverage. For business interruption purposes this excess coverage begins the later of full utilization of the primary business interruption coverage or 90 days from the date of the incident.

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 have a material effect on its 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) Variable Interest Entities and Guarantees

At December 31, 2004, the company had off-balance sheet arrangements with Variable Interest Entities, and indemnification agreements with other 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, 2004, $170 million in outstanding accounts receivable had been sold under the program. Under the recourse provisions, the company will provide indemnification against credit losses for certain counterparties, which did not exceed $50 million in 2004. A liability has not been recorded for this

indemnification as the company believes it has no significant exposure to credit losses. There were no new securitization proceeds in 2004. Proceeds from collections reinvested in securitizations on a revolving basis for the year ended December 31, 2004 were approximately $2,073 million. The company recorded an after-tax loss of approximately $2 million on the securitization program in 2004 (2003 and 2002 – $3 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 as at December 31, 2004, was 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 a specified date in 2005. Had the company elected to terminate the lease at December 31, 2004, the total cost would have been $25 million. Annualized equipment lease payments in 2004 were $6 million (2003 – $4 million; 2002 – $2 million).

The company has agreed to indemnify holders of the 7.15% notes, the 5.95% notes and the company's credit facility lenders (see note 6) 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, 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.

(d) Subsequent Event

On January 4, 2005, a fire occurred at the company's Oil Sands operations. The fire was confined to one of the upgraders, primarily affecting a coker fractionator. Daily production capacity at the Oil Sands facility has been reduced during the investigation and repair of fire-related damage.

12. PREFERRED SECURITIES

On March 15, 2004, the company redeemed all of its then outstanding 9.05% and 9.125% preferred securities for total cash consideration of $493 million. In 2004, dividends of $9 million were paid on the preferred securities (2003 – $45 million; 2002 – $48 million).

13. 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:

	Common Shares	
	Number (thousands)	Amount ($ millions)
Balance as at December 31, 2002	448 972	578
Issued for cash under stock option plans	1 977	20
Issued under dividend reinvestment plan	235	6
Balance as at December 31, 2003	451 184	604
Issued for cash under stock option plans	**2 880**	**41**
Issued under dividend reinvestment plan	**177**	**6**
Balance as at December 31, 2004	**454 241**	**651**

Common Share Options

A common share 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 and directors that hold options must earn the right to exercise them. This is done by the employee or director 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.

The predetermined price at which an option can be exercised is 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 1,346,000 common share options in 2004 (2003 – 1,902,000; 2002 – 1,803,000) 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 have a 10-year life and vest annually over a three-year

period.

(ii) SUNSHARE PERFORMANCE STOCK OPTION PLAN During 2004, the company granted 1,742,000 options (2003 –1,305,000; 2002 – 8,938,000) to eligible permanent full-time and part-time employees, both executive and non-executive, under its employee stock option incentive plan ("SunShare"). Under SunShare, meeting specified performance targets accelerates the vesting of some or all options.

In October 2004, the company met the predetermined performance criteria for the accelerated vesting of 2,097,000 common share options granted to executive and non-executive employees. The vested options represented approximately 20% of the then outstanding common share options granted under the SunShare plan. An additional 2,062,000 options, representing approximately 25% of outstanding SunShare options at December 31, 2004, will vest on January 31, 2005 in connection with the achievement of the second predetermined performance criterion. The remaining 60% of outstanding SunShare 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.

In 2004, the Board of Directors approved an additional 3,000,000 options available for grant under the SunShare plan.

(iii) KEY CONTRIBUTOR STOCK OPTION PLAN In 2004, the Board of Directors approved the establishment of the new Key Contributor stock option plan, under which 5,200,000 options were made available for grant to senior managers and key employees.

(iv) DEFERRED SHARE UNITS (DSUs) The company had 1,228,000 DSUs outstanding at December 31, 2004. DSUs were granted to certain executives under the company's former employee long-term incentive program. Certain members of the Board of Directors have also elected to receive DSUs in lieu of cash compensation. DSUs are only redeemable at the time a unitholder ceases employment or Board membership, as applicable.

In 2004, there were no redemptions of DSUs for cash (2003 – 185,000 redeemed for cash consideration of $5 million; 2002 – 220,000 redeemed for cash consideration of $6 million). Over time, DSU unitholders are entitled to receive additional DSUs equivalent in value to future notional dividend reinvestments. 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, 2004, the total liability related to the DSUs was $52 million, of which $2 million was classified as current (see note 8).

During 2004, total pretax compensation expense related to deferred share units was $12 million (2003 – $8 million; 2002 – income of $2 million).

(v) PERFORMANCE SHARE UNITS (PSUs) During 2004, the company issued 354,000 PSUs (2003 and 2002 – nil) under its new employee incentive compensation plan. PSUs granted replace the remuneration value of reduced grants under the company's stock option plans. PSUs vest and are settled in cash approximately three years after the grant date to varying degrees (0%, 50%, 100% and 150%) contingent upon Suncor's performance. Performance is measured by reference to the company's total shareholder return (stock price appreciation and dividend income) relative to a peer group of companies. Expense related to the PSUs is accrued based on the price of common shares at the end of the period and the probability of vesting. This expense is recognized on a straight-line basis over the term of the grant. Pretax expense recognized for PSUs during 2004 was $5 million (2003 and 2002 – $nil).

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

	Number (thousands)	Range of Exercise Prices ($)	Weighted-average Exercise Price Per Share ($)
Outstanding, December 31, 2001	11 768	2.38 – 21.35	12.12
Granted	10 741	23.93 – 28.14	27.08
Exercised	(1 777)	2.38 – 17.45	10.42
Cancelled	(406)	13.04 – 27.65	26.48
Outstanding, December 31, 2002	20 326	3.80 – 28.14	19.89
Granted	3 207	23.65 – 29.85	26.70
Exercised	(1 977)	3.80 – 23.93	10.35
Cancelled	(540)	10.13 – 27.93	20.94
Outstanding, December 31, 2003	21 016	4.11 – 29.85	21.69
Granted	3 088	30.63 – 42.02	34.52
Exercised	(2 880)	4.11 – 40.67	13.94
Cancelled	(537)	23.93 – 41.38	28.71
Outstanding, December 31, 2004	**20 687**	**5.22 – 42.02**	**24.49**
Exercisable, December 31, 2004	**9 067**	**5.22 – 40.67**	**18.78**

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

(thousands of common shares)	2004	2003	2002
	4 342	6 893	11 175

The following table is an analysis of outstanding and exercisable common share options as at December 31, 2004:

	Outstanding			Exercisable	

Exercise Prices ($)	Number (thousands)	Weighted-average Remaining Contractual Life	Weighted-average Exercise Price Per Share ($)	Number (thousands)	Weighted-average Exercise Price Per Share ($)
5.22 – 10.13	1 459	3	8.82	1 459	8.82
12.28 – 21.35	4 040	4	15.22	4 040	15.22
23.65 – 28.93	12 265	7	27.01	3 282	26.27
30.63 – 42.02	2 923	8	34.58	286	33.82
Total	20 687	6	24.49	9 067	18.78

(vi) 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:

	2004	2003	2002
Annual dividend per share	**$ 0.23**	$ 0.1925	$ 0.17
Risk-free interest rate	**3.79%**	4.39%	5.39%
Expected life	**6 years**	7 years	8 years
Expected volatility	**29%**	32%	31%
Weighted-average fair value per option	**$ 12.02**	$ 9.94	$ 12.08

The company's reported net earnings attributable to common shareholders and earnings per share prepared in accordance with the fair value method of accounting for stock-based compensation would have been reduced for all common share options granted prior to 2003 to the pro forma amounts stated below:

($ millions, except per share amounts)	2004	2003	2002
Net earnings attributable to common shareholders – as reported	**1 088**	1 085	722
Less: compensation cost under the fair value method for pre-2003 options	**47**	30	32
Pro forma net earnings attributable to common shareholders for pre-2003 options	**1 041**	1 055	690
Basic earnings per share			
As reported	**2.40**	2.41	1.61
Pro forma	**2.30**	2.35	1.54
Diluted earnings per share			
As reported	**2.36**	2.24	1.58
Pro forma	**2.26**	2.18	1.51

14. EARNINGS PER COMMON SHARE

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

($ millions)	2004	2003	2002
Net earnings attributable to common shareholders	**1 088**	1 085	722
Dividends on preferred securities, net of tax	**—**(a)	27	28
Revaluation of US$ preferred securities, net of tax	**—**(a)	(37)	(1)
Adjusted net earnings attributable to common shareholders	**1 088**	1 075	749
(millions of common shares)			
Weighted-average number of common shares	**453**	450	448
Dilutive securities:			
Options issued under stock-based compensation plans	**9**	8	5
Redemption of preferred securities by the issuance of common shares	**—**(a)	22	20
Weighted-average number of diluted common shares	**462**	480	473
(dollars per common share)			
Basic earnings per share (b)	**2.40**	2.41	1.61
Diluted earnings per share	**2.36**	2.24(c)	1.58(c)

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 year ended December 31, 2004, 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. The company redeemed its preferred securities in the first quarter of 2004.

(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.

15. FINANCING EXPENSES (INCOME)

($ millions)	2004	2003	2002
Interest on debt	**148**	140	155
Capitalized interest	**(61)**	(57)	(22)
Net interest expense	**87**	83	133
Foreign exchange (gain) on long-term debt	**(89)**	(166)	(9)
Other foreign exchange loss	**11**	17	—
Total financing expenses (income)	**9**	(66)	124

Cash interest payments in 2004 totalled $143 million (2003 – $139 million; 2002 – $134 million).

16. INVENTORIES

($ millions)	2004	2003
Crude oil	**109**	135
Refined products	**120**	134
Materials, supplies and merchandise	**194**	102
Total	**423**	371

As at December 31, 2004, the replacement cost of crude oil and refined product inventories, valued using the LIFO cost method, exceeded their carrying value by $65 million (2003 – $48 million).

During 2004, the company recorded a pretax gain of $8 million related to a permanent reduction in LIFO inventory layers.

17. RELATED PARTY TRANSACTIONS

The following table summarizes the company's related party transactions after 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)	2004	2003	2002
Operating revenues			
Sales to Energy Marketing and Refining – Canada segment joint-ventures:			
Refined products	**320**	301	321
Petrochemicals	**272**	187	142

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

At December 31, 2004, amounts due from Energy Marketing and Refining – Canada segment joint-ventures were $17 million (2003 – $36 million).

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

18. SUPPLEMENTAL INFORMATION

($ millions)	2004	2003	2002
Export sales (a)	**693**	549	501
Exploration expenses			
Geological and geophysical	**33**	18	13
Other	**1**	1	2
Cash costs	**34**	19	15
Dry hole costs	**21**	32	11
Cash and dry hole costs (b)	**55**	51	26
Leasehold impairment (c)	**8**	16	10
	63	67	36
Taxes other than income taxes			
Excise taxes (d)	**452**	388	340
Production, property and other taxes	**44**	38	34
	496	426	374

Allowance for doubtful accounts	**3**	4	

(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 2002, the company sold its retail natural gas marketing business in the Energy Marketing and Refining – Canada 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.

19. DIFFERENCES BETWEEN CANADIAN AND U.S. 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**	**2004**	**2003**	**2002**
Net earnings as reported, Canadian GAAP		**1 100**	1 075	749
Adjustments net of applicable income taxes				
Derivatives and hedging activities	(a)	**65**	(120)	6
Stock-based compensation	(b)	**(10)**	(2)	(12)
Preferred securities	(c)	**(12)**	12	(29)
Asset retirement obligations	(d)	**—**	5	12
Cumulative effect of change in accounting principles	(d)	**—**	(66)	—
Net earnings attributable to discontinued operations	(f)	**—**	—	(56)
Net earnings from continuing operations, U.S. GAAP		**1 143**	904	670
Net earnings from discontinued operations, U.S. GAAP	(f)	**—**	—	56
Derivatives and hedging activities, net of income taxes of $35 (2003 – $7; 2002 – $54)	(a)	**(67)**	18	(118)
Minimum pension liability, net of income taxes of $3 (2003 – $nil; 2002 – $10)	(e)	**5**	7	(20)
Foreign currency translation adjustment	(g)	**(29)**	(26)	—
Comprehensive income, U.S. GAAP		**1 052**	903	588

per common share (dollars)	**2004**	**2003**	**2002**
Net earnings per share from continuing operations			
Basic	**2.52**	2.01	1.50
Diluted	**2.47**	1.86	1.47
Net earnings per share from discontinued operations			
Basic	**—**	—	0.12
Diluted	**—**	—	0.12

The application of U.S. GAAP would have the following effects on the Consolidated Balance Sheets as reported:

		December 31, 2004		**December 31, 2003**	
	Notes	**As Reported**	**U.S. GAAP**	**As Reported**	**U.S. GAAP**
Current assets	(a),(h)	**1 195**	**1 300**	1 279	1 375
Property, plant and equipment, net	(c),(h)	**10 289**	**10 340**	8 936	8 974
Deferred charges and other	(a),(e)	**320**	**367**	286	333
Total assets		**11 804**	**12 007**	10 501	10 682
Current liabilities	(a)	**1 409**	**1 701**	1 060	1 349
Long-term borrowings	(a),(h)	**2 217**	**2 275**	2 448	2 967
Accrued liabilities and other	(e)	**749**	**815**	616	692
Future income taxes	(a),(c),(e)	**2 532**	**2 526**	2 022	2 015
Preferred securities	(c)	**—**	**—**	476	—
Share capital	(b)	**651**	**699**	604	652
Contributed surplus	(b)	**32**	**44**	7	9
Cumulative foreign currency translation	(g)	**(55)**	**—**	(26)	—
Retained earnings		**4 269**	**4 176**	3 294	3 136
Accumulated other comprehensive income	(a),(e),(g)	**—**	**(229)**	—	(138)
Total liabilities and shareholders' equity		**11 804**	**12 007**	10 501	10 682

(a) Derivative Financial Instruments

The company accounts for its derivative financial instruments under Canadian GAAP as described in note 7. Financial Accounting Standards Board Statement (Statement) 133, "Accounting for Derivative Instruments and Hedging Activities", as amended by Statements 138 and 149 (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 each period are recognized in the Consolidated 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") each period and are recognized in the Consolidated Statements of Earnings when the hedged item is recognized. Accordingly, ineffective portions of changes in the fair value of hedging instruments are recognized in net 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.

The determination of hedge effectiveness and the measurement of hedge ineffectiveness for cash flow hedges is based on internally derived valuations. The company uses these valuations to estimate the fair values of the underlying physical commodity contracts.

Commodity Price Risk

As described in note 7, Suncor manages crude price variability by entering into U.S. dollar WTI derivative transactions and has historically, in certain instances, combined U.S. dollar WTI derivative transactions and Canadian/U.S. foreign exchange derivative contracts. As at December 31, 2004 the company had hedged a portion of its forecasted Canadian dollar denominated cash flows subject to U.S. dollar WTI commodity price risk for 2005. The company had not hedged any portion of the foreign exchange component of these forecasted cash flows.

While the company's current strategic intent is to only manage the exposure relating to changes in the U.S. dollar WTI component of its crude oil sales, U.S. GAAP requires the company to consider all cash flows arising from forecasted Canadian dollar denominated crude oil sales when measuring the ineffectiveness of its cash flow hedges. In periods of significant Canadian/U.S. dollar foreign exchange fluctuations, material hedge ineffectiveness can result from unhedged foreign exchange exposures. This ineffectiveness arises despite the company's assessment that its U.S. dollar WTI hedging instruments are highly effective in achieving offsetting changes in cash flows attributable to its forecasted Canadian dollar denominated crude oil sales.

Under U.S. GAAP, for the year ended December 31, 2004, the company would have recognized $57 million of hedge ineffectiveness relating to forecasted cash flows in 2005 primarily due to foreign exchange fluctuations during the period. The net earnings impact of this ineffectiveness will not be recognized for Canadian GAAP purposes until the related forecasted crude oil sales occur in 2005.

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, 2004, the company had interest rate derivatives classified as fair value hedges outstanding for up to seven years relating to fixed rate debt.

De-designated Hedging Instruments

During 2003, the company de-designated and monetized purchased crude oil call option hedging instruments for net proceeds of $28 million. For Canadian GAAP purposes, as it was probable that the underlying forecasted crude oil sales would occur, the related $28 million pretax gain on monetization of the call options was deferred and will be recognized as additional crude oil revenues during 2004. For US GAAP purposes, the company would have recognized the $28 million pre tax gain as hedge ineffectiveness income during 2003.

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 did not have purchase price risk associated with the repurchase of the inventory. This derivative did not represent a U.S. GAAP difference as the company recorded 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 18), 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.

Accumulated OCI and U.S. GAAP Net Earnings Impacts

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

($ millions)	2004	2003
OCI attributable to derivatives and hedging activities, beginning of the period, net of income taxes of $34 (2003 – $41)	**(71)**	(89)
Current period net changes arising from cash flow hedges, net of income taxes of $61 (2003 – $26)	**(122)**	(54)
Net hedging losses at the beginning of the period reclassified to earnings during the period, net of income taxes of $26 (2003 – $33)	**55**	72

OCI attributable to derivatives and hedging activities, end of period, net of income taxes of $69 (2003 – $34)	**(138)**	(71)

For the year ended December 31, 2004, assets increased by $133 million and liabilities increased by $328 million as a result of recording all derivative instruments at fair value.

The loss associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the period was $130 million, net of income taxes of $66 million (2003 – loss of $199 million, net of income taxes of $93 million; 2002 – loss of $19 million, net of income taxes of $9 million). The company estimates that $139 million of after-tax hedging losses will be reclassified from OCI to current period earnings within the next 12 months as a result of forecasted sales occurring.

For the year ended December 31, 2004, U.S. GAAP net earnings would have increased by $65 million, net of income taxes of $27 million (2003 – decreased net earnings of $120 million, net of income taxes of $56 million; 2002 – increased net earnings of $6 million, net of income taxes of $4 million) to reflect the impact of the above items.

(b) Stock-based Compensation

Under Canadian GAAP, compensation expense has not been recognized for common share options granted prior to January 1, 2003, including options issued in connection with both the company's SunShare long-term incentive plan, as well as those common shares and common share options awarded to employees under the company's previous long-term incentive program that matured April 1, 2002. Under U.S. GAAP, certain of the SunShare options would have been accounted for using the variable method of accounting for employee stock compensation. Further, for U.S. GAAP purposes, compensation expense would have been recognized ratably over the life of the previous long-term incentive program for those options and common shares awarded under that plan. For the year ended December 31, 2004, U.S. GAAP net earnings would have been reduced by $10 million (2003 – $2 million; 2002 – $12 million) to reflect additional stock-based compensation expense.

The company now expenses the compensation cost of all common share options issued after January 1, 2003, ratably over the estimated vesting period of the respective options. For U.S. GAAP purposes, the company would have adopted Statement 148 in 2003, permitting the company to expense common share options issued after January 1, 2003, in a manner consistent with Canadian GAAP.

Consistent with Canadian GAAP, for U.S. GAAP purposes the company would have continued to disclose pro forma stock-based compensation cost for common stock options awarded prior to January 1, 2003 ("pre-2003 options") as if the fair value method had been adopted. Under U.S. GAAP, had the company accounted for its pre-2003 options using the fair value method (excluding the earnings effect of the SunShare and long-term employee incentive options described above), pro forma net earnings and pro forma basic earnings per share for the year ended December 31, 2004, would have been reduced by $37 million (2003 – $27 million; 2002 – $24 million) and $0.08 per share (2003 – $0.06; 2002 – $0.05), respectively.

(c) Preferred Securities

Under Canadian GAAP, preferred securities were classified as shareholders' equity and the interest distributions thereon, net of income taxes, were 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 Consolidated 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, were charged against shareholders' equity. Under U.S. GAAP, these issue costs would have been deferred and amortized to earnings over the term of the related long-term debt.

For U.S. GAAP purposes, these differences would have reduced net earnings for the year ended December 31, 2004 by $12 million, net of income taxes of $6 million (2003 – an increase to net earnings of $12 million, net of an income tax recovery of $8 million; 2002 – a reduction to net earnings of $29 million, net of income taxes of $20 million).

Under Canadian GAAP, the interest distributions on the preferred securities for the year ended December 31, 2004 of $9 million (2003 – $45 million; 2002 – $48 million) were classified as financing activities in the Consolidated Statements of Cash Flows. Under U.S. GAAP, the interest distributions of $9 million (2003 – $45 million; 2002 – $48 million) and the amortization of issue costs for the year ended December 31, 2004, of $1 million (2003 – $3 million; 2002 – $3 million) would have been classified as operating activities.

The preferred securities were redeemed on March 15, 2004.

(d) Asset Retirement Obligations

Under Canadian GAAP, the company retroactively adopted Canadian accounting standards related to asset retirement obligations (AROs) on January 1, 2004, with restatements of all prior period comparative amounts. Under U.S. GAAP the company would have adopted AROs on January 1, 2003, and would have been required to record the cumulative effect of the change in accounting policy in 2003 earnings. This GAAP difference would have decreased U.S. GAAP net earnings by $61 million in 2003 and increased net earnings by $12 million in 2002.

(e) 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. For the purposes of determining the additional minimum pension liability, the accumulated benefit obligation does not incorporate projections of future compensation increases in

the determination of the obligation. No such adjustment is required under Canadian GAAP.

Under U.S. GAAP, at December 31, 2004, the company would have recognized a minimum pension liability of $66 million (2003 – $76 million), an intangible asset of $11 million (2003 – $13 million) and other comprehensive loss of $36 million, net of income taxes of $19 million (2003 – $41 million, net of income taxes of $22 million). Other comprehensive income for the year ended December 31, 2004 would have increased by $5 million, net of income taxes of $3 million (2003 – an increase in other comprehensive income of $7 million, net of income taxes of $nil; 2002 – a decrease in other comprehensive income of $20 million, net of income taxes of $10 million).

(f) Discontinued Operations

During 2002, the company disposed of its retail natural gas business for net proceeds of $62 million, and recognized an after-tax gain on sale of $35 million 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 business would have been considered a distinguishable component of the company, and reflected as a discontinued operation for the year ended December 31, 2002. For segmented reporting purposes, the retail natural gas marketing business was included in the Energy Marketing and Refining – Canada operating segment in 2002.

Selected financial information regarding the discontinued retail natural gas business is as follows for the year ended December 31:

($ millions)	2004	2003	2002
Revenues included in discontinued operations	—	—	81
Income from retail natural gas business operations, net of income taxes of $nil (2003 – $nil; 2002 – $4)	—	—	8
Gain on disposal of retail natural gas business, net of income taxes of $nil (2003 – $nil; 2002 – $10)	—	—	48

There were no remaining assets or liabilities related to the discontinued operations at December 31, 2004 or at December 31, 2003.

(g) Cumulative Foreign Currency Translation

Under Canadian GAAP, foreign currency losses of $29 million (2003 – $26 million) arising on translation of the company's Denver-based foreign operations have been recorded directly to shareholders' equity. Under U.S. GAAP, these foreign currency translation losses would be included as a component of comprehensive income.

(h) Variable Interest Entities

For U.S. GAAP purposes, the company would be required to consolidate the VIE related to the sale of equipment as described in note 11(c) as of January 1, 2004. The impact on the December 31, 2004, balance sheet would be an increase to property, plant and equipment of $14 million, an increase to inventory of $8 million and an increase to long-term debt of $22 million.

The accounts receivable securitization program, as currently structured, does not meet the FIN 46(R) criteria for consolidation by Suncor.

Recently Issued Accounting Standards

In December 2004, the U.S. Financial Accounting Standards Board issued SFAS 123(R), "Share-Based Payment". The standard, effective July 1, 2005, requires the recognition of an expense for employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. The cost is to be recognized over the period for which an employee is required to provide the service in exchange for the award. In addition, SFAS 123(R) requires recognition of compensation expense for the portion of outstanding unvested awards granted prior to the effective date. The company currently records an expense under Canadian GAAP for all common share options issued on or after January 1, 2003, with a corresponding increase recorded as contributed surplus in the Consolidated Statements of Changes in Shareholders' Equity. The company expects that adoption of SFAS 123(R) on July 1, 2005, for U.S. GAAP reporting will not have a significant impact on net earnings.

quarterly summary (unaudited)

FINANCIAL DATA

	For the Quarter Ended		For the Quarter Ended	

($ millions except per share amounts)	Mar 31 2004	June 30 2004	Sept 30 2004	Dec 31 2004	Total Year 2004	Mar 31 2003	June 30 2003	Sept 30 2003	Dec 31 2003	Total Year 2003
Revenues	**1 795**	**2 201**	**2 315**	**2 310**	**8 621**	1 700	1 385	1 788	1 698	6 571
Net earnings (loss)										
Oil Sands	**238**	**232**	**263**	**262**	**995**	305	70	259	254	888
Natural Gas	**22**	**35**	**23**	**35**	**115**	27	28	26	39	120
Energy Marketing and Refining – Canada	**30**	**(3)**	**29**	**24**	**80**	21	17	9	6	53
Refining and Marketing – U.S.A (c)	**(3)**	**12**	**15**	**10**	**34**	—	—	14	4	18
Corporate and eliminations	**(60)**	**(73)**	**7**	**2**	**(124)**	13	1	(17)	(1)	(4)
	227	**203**	**337**	**333**	**1 100**	366	116	291	302	1 075
Per common share										
Net earnings attributable to common shareholders										
Basic	**0.48**	**0.44**	**0.74**	**0.73**	**2.40**	0.84	0.27	0.63	0.67	2.41
Diluted	**0.46**	**0.43**	**0.73**	**0.72**	**2.36**	0.77	0.24	0.62	0.61	2.24
Cash dividends	**0.05**	**0.06**	**0.06**	**0.06**	**0.23**	0.0425	0.05	0.05	0.05	0.1925
Cash flow from (used in) operations										
Oil Sands	**365**	**421**	**509**	**457**	**1 752**	541	321	488	453	1 803
Natural Gas	**83**	**90**	**80**	**66**	**319**	88	66	80	64	298
Energy Marketing and Refining – Canada	**56**	**23**	**52**	**57**	**188**	49	41	27	47	164
Refining and Marketing – U.S.A (c)	**(6)**	**21**	**21**	**23**	**59**	—	—	25	9	34
Corporate and eliminations	**(76)**	**(65)**	**(77)**	**(79)**	**(297)**	(65)	(70)	(36)	(49)	(220)
	422	**490**	**585**	**524**	**2 021**	613	358	584	524	2 079

OPERATING DATA

OIL SANDS

(thousands of barrels per day)										
Production										
Base operations	**213.9**	**210.8**	**230.2**	**206.9**	**215.6**	211.1	188.2	231.5	235.2	216.6
Firebag	**5.9**	**15.1**	**7.3**	**15.6**	**10.9**	—	—	—	—	—
	219.8	**225.9**	**237.5**	**222.5**	**226.5**	211.1	188.2	231.5	235.2	216.6
Sales										
Light sweet crude oil	**112.2**	**118.7**	**113.5**	**115.3**	**114.9**	120.7	86.4	109.0	132.7	112.3
Diesel	**27.5**	**29.7**	**28.7**	**25.5**	**27.9**	30.1	22.9	24.8	27.2	26.3
Light sour crude oil	**74.3**	**68.9**	**76.3**	**80.9**	**75.1**	60.4	73.9	77.5	81.3	73.3
Bitumen	**—**	**14.5**	**7.9**	**11.0**	**8.4**	—	1.2	16.1	8.3	6.4
	214.0	**231.8**	**226.4**	**232.7**	**226.3**	211.2	184.4	227.4	249.5	218.3

	For the Quarter Ended					For the Quarter Ended				
	Mar 31 2004	June 30 2004	Sept 30 2004	Dec 31 2004	Total Year 2004	Mar 31 2003	June 30 2003	Sept 30 2003	Dec 31 2003	Total Year 2003
OIL SANDS (continued)										
Average sales price (1)										
(dollars per barrel)										
Light sweet crude oil	**40.26**	**45.70**	**46.03**	**50.55**	**45.60**	46.69	39.87	37.96	36.67	40.26
Other (diesel, light sour crude oil and bitumen)	**35.85**	**38.28**	**42.29**	**39.62**	**39.13**	40.62	32.94	32.92	30.72	33.93
Total	**38.16**	**41.88**	**44.08**	**44.68**	**42.28**	44.09	36.19	35.34	33.89	37.19
Total (a)	**43.28**	**48.18**	**52.72**	**54.40**	**49.78**	48.77	38.14	38.05	36.63	40.22
(dollars per barrel sold rounded to the nearest $0.05)										
Cash operating costs and total operating costs – Base Operations										
Cash costs	**9.65**	**9.75**	**9.00**	**10.90**	**9.80**	9.20	10.70	8.20	9.25	9.25
Natural gas	**2.10**	**2.30**	**1.40**	**2.20**	**2.00**	3.10	2.45	1.65	1.60	2.15
Imported bitumen	**0.40**	**0.05**	**0.10**	**0.10**	**0.15**	0.10	0.10	—	—	0.05
Cash operating costs (2)	**12.15**	**12.10**	**10.50**	**13.20**	**11.95**	12.40	13.25	9.85	10.85	11.45
Firebag start-up costs	**1.20**	**—**	**—**	**—**	**0.30**	—	—	—	—	—
Total cash operating costs (3)	**13.35**	**12.10**	**10.50**	**13.20**	**12.25**	12.40	13.25	9.85	10.85	11.45
Depreciation, depletion and amortization	**6.20**	**6.15**	**5.70**	**6.25**	**6.10**	6.30	6.30	5.30	5.40	5.80
Total operating costs (4)	**19.55**	**18.25**	**16.20**	**19.45**	**18.35**	18.70	19.55	15.15	16.25	17.25
Cash operating costs and total operating costs – Firebag										
Cash costs	**—**	**6.55**	**14.90**	**7.00**	**8.30**	—	—	—	—	—
Natural gas	**—**	**11.65**	**11.90**	**10.45**	**11.20**	—	—	—	—	—
Cash operating costs (5)	**—**	**18.20**	**26.80**	**17.45**	**19.50**	—	—	—	—	—
Depreciation, depletion and amortization	**—**	**5.80**	**7.45**	**5.55**	**6.00**	—	—	—	—	—
Total operating costs (6)	**—**	**24.00**	**34.25**	**23.00**	**25.50**	—	—	—	—	—
NATURAL GAS										
Gross production (b)										
Natural gas (millions of cubic feet per day)	**197**	**209**	**201**	**193**	**200**	184	175	194	194	187
Natural gas liquids (thousands of barrels per day)	**2.2**	**2.2**	**2.6**	**2.9**	**2.5**	2.4	2.1	2.5	2.4	2.3
Crude oil (thousands of barrels per day)	**0.9**	**1.1**	**1.0**	**1.0**	**1.0**	1.4	1.6	1.6	1.0	1.4
Total (barrel of oil equivalent per day at 6:1 for natural gas)	**35.9**	**38.1**	**37.1**	**36.1**	**36.8**	34.5	32.8	36.4	35.7	34.9
Average sales price (1)										
Natural gas (dollars per thousand cubic feet)	**6.54**	**6.77**	**6.49**	**7.02**	**6.70**	7.54	6.63	6.07	5.53	6.42
Natural gas (a) (dollars per thousand cubic feet)	**6.59**	**6.84**	**6.53**	**6.98**	**6.73**	7.59	6.65	6.04	5.51	6.42
Natural gas liquids (dollars per barrel)	**38.13**	**43.53**	**42.06**	**46.46**	**42.82**	41.65	33.45	33.50	35.45	36.08
Crude oil – conventional (dollars per barrel)	**44.14**	**47.08**	**55.43**	**55.26**	**50.41**	47.75	37.82	38.31	36.91	40.29

	For the Quarter Ended					For the Quarter Ended				
	Mar 31 2004	June 30 2004	Sept 30 2004	Dec 31 2004	Total Year 2004	Mar 31 2003	June 30 2003	Sept 30 2003	Dec 31 2003	Total Year 2003
ENERGY MARKETING AND REFINING – CANADA										
Refined product sales (thousands of cubic metres per day)	**15.2**	**15.5**	**15.3**	**15.6**	**15.4**	15.7	14.9	15.2	14.2	15.0
Margins										
Refining (7) (cents per litre)	**7.8**	**7.4**	**8.8**	**7.9**	**8.0**	7.5	4.7	6.5	7.0	6.5
Refining (7), (a) (cents per litre)	**7.8**	**8.0**	**8.8**	**7.8**	**8.1**	7.8	4.2	6.4	6.9	6.4
Retail (8) (cents per litre)	**5.0**	**4.3**	**3.7**	**4.5**	**4.4**	7.0	6.2	7.0	6.3	6.6
Utilization of refining capacity (%)	**108**	**85**	**104**	**101**	**100**	103	100	91	86	95
REFINING AND MARKETING – U.S.A. (c)										
Refined product sales (thousands of cubic metres per day)	**8.1**	**8.9**	**10.9**	**9.5**	**9.3**	—	—	9.8	8.6	9.1
Margins										
Refining (7) (cents per litre)	**5.0**	**9.0**	**5.1**	**7.7**	**6.7**	—	—	7.9	4.6	5.9
Refining (7), (a) (cents per litre)	**5.0**	**9.3**	**5.3**	**7.7**	**6.8**	—	—	7.9	4.6	5.9
Retail (8) (cents per litre)	**5.0**	**6.2**	**4.2**	**6.0**	**5.4**	—	—	6.4	4.8	5.6
Utilization of refining capacity (%)	**85**	**86**	**99**	**100**	**92**	—	—	101	96	98

(a) Excludes the impact of hedging activities.
(b) Currently all Natural Gas production is located in the Western Canada Sedimentary Basin.
(c) Refining and Marketing – U.S.A. reflects the results of operations since acquisition on August 1, 2003.

Definitions

(1) Average sales price – Calculated before royalties and net of related transportation costs (including or excluding the impact of hedging activities as noted).
(2) Cash operating costs – base operations – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense, taxes other than income taxes and the cost of bitumen imported from third parties. Per barrel amounts are based on production volumes. For a reconciliation of this non GAAP financial measure see page 52 of MD&A.
(3) Total cash operating costs – base operations – Include cash operating costs – base operations as defined above and cash start-up costs for in-situ operations. Per barrel amounts are based on mining production volumes.
(4) Total operating costs – base operations – Include total cash operating costs – base operations as defined above and non-cash operating costs. Per barrel amounts are based on mining production volumes.
(5) Cash operating costs – Firebag – Include cash costs that are defined as operating, selling and general expenses (excluding inventory changes), accretion expense and taxes other than income taxes. Per barrel amounts are based on in-situ production volumes.
(6) Total operating costs – Firebag – Include cash operating costs – Firebag as defined above and non-cash operating costs. Per barrel amounts are based on in-situ production volumes.
(7) Refining margin – Calculated as the average wholesale unit price from all products less average unit cost of crude oil.
(8) Retail margin – Calculated as the average street price of Sunoco (Energy, Marketing and Refining – Canada) and Phillips 66-branded (Refining and Marketing – U.S.A.) retail gasoline net of federal excise tax and other adjustments, less refining gasoline transfer price.

Metric conversion

Crude oil, refined products, etc. – $1m^3$ (cubic metre) = approx. 6.29 barrels
Natural gas – $1m^3$ (cubic metre) = approx. 35.49 cubic feet

five-year financial summary (unaudited)

($ millions except for ratios)	2004	2003(a)	2002	2001	2000
Revenues					
Oil Sands	**3 596**	3 061	2 616	1 372	1 402
Natural Gas	**567**	512	339	481	458
Energy Marketing and Refining – Canada	**3 460**	2 936	2 508	2 673	2 604
Refining and Marketing – U.S.A.	**1 495**	515	—	—	—
Corporate and eliminations	**(497)**	(453)	(431)	(232)	(980)
	8 621	6 571	5 032	4 294	3 484
Net earnings (loss)					
Oil Sands	**995**	888	782	273	303
Natural Gas	**115**	120	34	116	95
Energy Marketing and Refining – Canada	**80**	53	61	79	80
Refining and Marketing – U.S.A.	**34**	18	—	—	—

Corporate and eliminations	**(124)**	(4)	(128)	(92)	(117)
	1 100	1 075	749	376	361
Cash flow from (used in) operations					
Oil Sands	**1 752**	1 803	1 475	486	655
Natural Gas	**319**	298	164	280	238
Energy Marketing and Refining – Canada	**188**	164	112	165	174
Refining and Marketing – U.S.A.	**59**	34	—	—	—
Corporate and eliminations	**(297)**	(220)	(311)	(100)	(109)
	2 021	2 079	1 440	831	958
Capital and exploration expenditures					
Oil Sands	**1 118**	948	617	1 479	1 808
Natural Gas	**279**	183	163	132	127
Energy Marketing and Refining – Canada	**228**	122	60	54	45
Refining and Marketing – U.S.A.	**190**	31	—	—	—
Corporate	**31**	32	37	13	18
	1 846	1 316	877	1 678	1 998
Total assets	**11 804**	10 501	9 011	8 430	7 174
Capital employed (b)					
Short-term and long-term debt, less cash and cash equivalents	**2 159**	2 091	2 671	3 143	2 235
Shareholders' equity	**4 897**	4 355	3 397	2 731	2 435
	7 056	6 446	6 068	5 874	4 670
Less capitalized costs related to major projects in progress	**(1 467)**	(1 122)	(511)	(3 691)	(2 497)
	5 589	5 324	5 557	2 183	2 173
Total Suncor employees (number at year-end)	**4 605**	4 231	3 422	3 307	3 043

	2004	2003(a)	2002	2001	2000
Dollars per common share					
Net earnings attributable to common shareholders	**2.40**	2.41	1.61	0.76	0.74
Cash dividends	**0.23**	0.1925	0.17	0.17	0.17
Cash flow from operations	**4.46**	4.62	3.22	1.87	2.16
Cash flow from operations after deducting dividends paid on preferred securities	**4.44**	4.52	3.11	1.76	2.06
Ratios					
Return on capital employed (%) (c)	**19.1**	18.4	14.6	17.7	16.3
Return on capital employed (%) (d)	**16.2**	16.0	13.7	7.3	9.1
Return on shareholders' equity (%) (e)	**23.8**	27.7	24.4	14.6	16.0
Debt to debt plus shareholders' equity (%) (f)	**31.4**	36.3	44.2	53.5	48.1
Net debt to cash flow from operations (times) (g)	**1.1**	1.0	1.9	3.8	2.3
Interest coverage – cash flow basis (times) (h)	**14.7**	15.7	10.6	5.9	9.0
Interest coverage – net earnings basis (times) (i)	**11.6**	13.5	8.1	3.6	5.4

(a) Refining and Marketing – U.S.A. reflects the results of operations since acquisition on August 1, 2003.

(b) Capital employed – the sum of shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents, less capitalized costs related to major projects in progress (as applicable).

(c) Net earnings adjusted for after-tax financing expenses (income) for the 12-month period ended; divided by average capital employed. Average capital employed is the sum of shareholders' equity and short-term debt plus long-term debt less cash and cash equivalents at the beginning and end of the year, divided by two, less average capitalized costs related to major projects in progress (as applicable). Return on capital employed (ROCE) for Suncor operating segments presented in the Quarterly Summary is calculated in a manner consistent with consolidated ROCE. For a detailed annual reconciliation of this non GAAP financial measure see page 51 of MD&A.

(d) If capital employed were to include capitalized costs related to major projects in progress, the return on capital employed would be as stated on this line.

(e) Net earnings as a percentage of average shareholders' equity. Average shareholders' equity is the sum of total shareholders' equity at the beginning and end of the year divided by two.

(f) Short-term debt plus long-term debt; divided by the sum of short-term debt, long-term debt and shareholders' equity.

(g) Short-term debt plus long-term debt less cash and cash equivalents; divided by cash flow from operations for the year then ended.

(h) Cash flow from operations plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

(i) Net earnings plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

share trading information (unaudited)

Common shares are listed on the Toronto Stock Exchange and New York Stock Exchange under the symbol SU. The following share trading information reflects a two-for-one split of the company's common shares during 2002.

	For the Quarter Ended				For the Quarter Ended			
	Mar 31 2004	June 30 2004	Sept 30 2004	Dec 31 2004	Mar 31 2003	June 30 2003	Sept 30 2003	Dec 31 2003
Share ownership								
Average number outstanding, weighted monthly (thousands) (a)	**452 123**	**452 283**	**452 565**	**453 900**	449 187	449 485	449 756	450 505
Share price (dollars)								
Toronto Stock Exchange								
High	**38.02**	**36.80**	**41.49**	**44.49**	27.50	26.60	27.14	32.85
Low	**31.62**	**30.95**	**32.80**	**38.20**	23.87	23.31	24.75	25.07
Close	**35.97**	**34.01**	**40.40**	**42.40**	25.61	25.34	24.93	32.50
New York Stock Exchange – US$								
High	**28.75**	**28.09**	**32.63**	**36.15**	18.50	19.68	19.59	25.42
Low	**24.68**	**22.55**	**24.90**	**31.16**	15.32	16.10	17.86	18.57
Close	**27.35**	**25.61**	**32.01**	**35.40**	17.47	18.75	18.55	25.06
Shares traded (thousands)								
Toronto Stock Exchange	**100 401**	**109 073**	**102 460**	**86 424**	83 756	67 815	64 875	93 538
New York Stock Exchange	**45 120**	**59 254**	**64 519**	**66 536**	23 600	23 369	21 725	27 138
Per common share information(dollars)								
Net earnings attributable to common shareholders	**0.48**	**0.44**	**0.74**	**0.73**	0.84	0.27	0.63	0.67
Cash dividends	**0.05**	**0.06**	**0.06**	**0.06**	0.0425	0.05	0.05	0.05

(a) The company had approximately 2,375 holders of record of common shares as at January 31, 2005.

Information for Security Holders Outside Canada

Cash dividends paid to shareholders resident in countries with which Canada has an income tax convention are usually subject to Canadian non-resident withholding tax of 15%. The withholding tax rate is reduced to 5% on dividends paid to a corporation if it is a resident of the United States that owns at least 10% of the voting shares of the company.

supplemental financial and operating information (unaudited)

	2004	2003	2002	2001	2000
OIL SANDS					
Production (thousands of barrels per day)	**226.5**	216.6	205.8	123.2	113.9
Sales (thousands of barrels per day)					
Light sweet crude oil	**114.9**	112.3	104.7	56.2	64.3
Diesel	**27.9**	26.3	23.0	14.8	9.3
Light sour crude oil	**75.1**	73.3	68.3	42.0	35.8
Bitumen	**8.4**	6.4	9.3	8.5	6.2
	226.3	218.3	205.3	121.5	115.6
Average sales price (dollars per barrel)					
Light sweet crude oil	**45.60**	40.26	37.56	34.17	35.31
Other (diesel, light sour crude oil and bitumen)	**39.13**	33.93	29.58	24.86	27.09
Total	**42.28**	37.19	33.65	29.17	31.67
Total (a)	**49.78**	40.22	36.94	34.21	41.29
Cash operating costs – base operations (b)	**11.95**	11.45	11.15	11.35	11.50
Total cash operating costs – base operations (b)	**12.25**	11.45	11.15	11.35	11.50
Total operating costs – base operations (b)	**18.35**	17.25	17.25	16.70	17.25
Cash operating costs – Firebag (b), (e)	**19.50**				
Total operating costs – Firebag (b), (e)	**25.50**				
Capital employed excluding major projects in progress	**4 169**	4 050	4 512	1 378	1 402
Return on capital employed (%) (c)	**22.9**	20.8	16.7	19.6	22.1
Return on capital employed (%) (d)	**18.8**	17.4	15.6	6.2	10.2

(a) Excludes the impact of hedging activities.
(b) Dollars per barrel rounded to the nearest $0.05. See definitions on page 95.
(c) See definitions on page 97.
(d) If capital employed were to include capitalized costs related to major projects in progress, the return on capital employed would be as stated on this line.
(e) Firebag commenced commercial operations on April 1, 2004.

	2004	2003	2002	2001	2000
NATURAL GAS					
Production					
Natural gas (millions of cubic feet per day)					
Gross	**200**	187	179	177	200
Net	**147**	142	124	124	142
Natural gas liquids (thousands of barrels per day)					
Gross	**2.5**	2.3	2.4	2.4	3.0
Net	**1.8**	1.7	1.7	1.7	2.1
Crude oil (thousands of barrels per day)					
Gross	**1.0**	1.4	1.5	1.5	4.2
Net	**0.8**	1.1	1.2	1.1	3.3
Total (thousands of boe (a) per day)					
Gross	**36.8**	34.9	33.7	33.4	40.5
Net	**27.1**	26.4	23.6	23.5	29.1
Average sales price					
Natural gas (dollars per thousand cubic feet)	**6.70**	6.42	3.91	6.09	4.72
Natural gas (dollars per thousand cubic feet) (b)	**6.73**	6.42	3.91	6.12	4.73
Natural gas liquids (dollars per barrel)	**42.82**	36.08	29.35	34.38	36.66
Crude oil – conventional (dollars per barrel)	**50.41**	40.29	31.72	33.92	29.50
Capital employed	**448**	400	422	291	387
Return on capital employed (%) (e)	**27.1**	29.2	9.5	34.2	17.8
Undeveloped landholdings (c)					
Oil and gas (millions of acres)					
Western Canada					
Gross	**0.7**	0.5	0.5	0.6	1.4
Net	**0.5**	0.4	0.4	0.5	1.1
International					
Gross	**0.7**	0.9	1.2	1.7	1.3
Net	**0.4**	0.2	0.7	1.3	1.1
Net wells drilled (d)					
Exploratory					
Oil	**—**	—	—	—	—
Gas	**5**	2	2	4	1
Dry	**5**	31	19	16	15
Development					
Oil	**—**	1	—	—	2
Gas	**16**	16	18	16	14
Dry	**—**	4	4	2	3
	26	54	43	38	35

(a) Barrel of oil equivalent – converts natural gas to oil on the approximate energy equivalent basis that 6,000 cubic feet equals one barrel of oil.
(b) Excludes the impact of hedging activities.
(c) Metric conversion: Landholdings – 1 hectare = approximately 2.5 acres.
(d) Excludes interests in eleven net exploratory wells and three net development wells in progress at the end of 2004.
(e) See definitions on page 97.

	2004	2003	2002	2001	2000
ENERGY MARKETING AND REFINING – CANADA					
Refined product sales (thousands of cubic metres per day)					
Transportation fuels					
Gasoline					
Retail (b)	**4.6**	4.4	4.5	4.3	4.2
Other	**4.1**	4.2	4.4	4.4	4.0
Jet fuel	**0.9**	0.7	0.4	0.7	1.1

Diesel	**3.1**	3.0	2.9	3.1	3.1
	12.7	12.3	12.2	12.5	12.4
Petrochemicals	**0.8**	0.8	0.6	0.5	0.6
Heating oils	**0.4**	0.5	0.4	0.4	0.4
Heavy fuel oils	**0.7**	0.8	0.6	0.8	0.6
Other	**0.8**	0.6	0.7	0.6	0.6
	15.4	15.0	14.5	14.8	14.6
Margins (cents per litre)					
Refining	**8.0**	6.5	4.8	5.7	5.9
Refining (c)	**8.1**	6.4	4.8	5.7	5.9
Retail	**4.4**	6.6	6.6	6.6	6.6
Crude oil supply and refining					
Processed at Sarnia refinery (thousands of cubic metres per day)	**11.1**	10.5	10.6	10.2	10.9
Utilization of refining capacity (%)	**100**	95	95	92	98
Capital employed excluding major projects in progress	**512**	551	485	480	384
Return on capital employed (%) (d)	**14.6**	10.3	12.0	18.3	20.3
Return on capital employed (%) (d), (e)	**13.6**	10.3	12.0	18.3	20.3
Retail outlets (f) (number at year-end)	**385**	379	384	400	402

	2004	2003	2002	2001	2000
REFINING AND MARKETING – U.S.A. (a)					
Refined product sales (thousands of cubic metres per day)					
Transportation fuels					
Gasoline					
Retail (b)	**0.7**	0.7	—	—	—
Other	**3.8**	3.5	—	—	—
Jet fuel	**0.5**	0.5	—	—	—
Diesel	**2.2**	2.3	—	—	—
	7.2	7.0	—	—	—
Asphalt	**1.5**	1.7	—	—	—
Other	**0.6**	0.4	—	—	—
	9.3	9.1	—	—	—
Margins (cents per litre)					
Refining	**6.7**	5.9	—	—	—
Refining (c)	**6.8**	5.9	—	—	—
Retail	**5.4**	5.6	—	—	—
Crude oil supply and refining					
Processed at Denver refinery (thousands of cubic metres per day)	**8.8**	9.4	—	—	—
Utilization of refining capacity (%)	**92**	98	—	—	—
Capital employed excluding major projects in progress	**232**	270			
Return on capital employed (%) (d), (h)	**12.2**	—			
Return on capital employed (%) (d), (e)	**11.0**	—			
Retail outlets (g) (number at year-end)	**43**	43	—	—	—

(a) Refining and Marketing – U.S.A. reflects the results of operations since acquisition on August 1, 2003.
(b) Excludes sales through joint-venture interests.
(c) Excludes the impact of hedging activities.
(d) See definitions on page 97.
(e) If capital employed were to include capitalized costs related to major projects in progress, the return on capital employed would be as stated on this line.
(f) Sunoco-branded service stations, other private brands managed by EM&R and EM&R's interest in service stations managed through joint-ventures. Outlets are located mainly in Ontario.
(g) Phillips 66-branded service stations. Outlets are primarily located in the Denver, Colorado area.
(h) For 2003, represents five months of operations since acquisition August 1, 2003 therefore no annual ROCE was calculated.

investor information

Stock Trading Symbols and Exchange Listing

Common shares are listed on the Toronto Stock Exchange and New York Stock Exchange under the symbol SU.

Dividends

Suncor's Board of Directors reviews its dividend policy quarterly. Effective the second quarter of 2004, dividends were increased to $0.06 per share from $0.05 per share resulting in an aggregate 2004 dividend of $0.23 per common share.

Dividend Reinvestment and Common Share Purchase Plan

Suncor's Dividend Reinvestment and Common Share Purchase Plan enables shareholders to invest cash dividends in common shares or acquire additional shares through optional cash payments without payment of brokerage commissions, service charges or other costs associated with administration of the plan. To obtain additional information, call Computershare Trust Company of Canada at 1-877-982-8760 or visit www.computershare.com. Information regarding the purchase plan is also available at www.suncor.com.

Stock Transfer Agent and Registrar

In Canada, Suncor's agent is Computershare Trust Company of Canada. In the United States, Suncor's agent is Computershare Trust Company, Inc.

Independent Auditors

PricewaterhouseCoopers LLP

Independent Reserve Evaluators

Gilbert Laustsen Jung Associates Ltd.

Annual Meeting

Suncor's annual and special meeting of shareholders will be held at 10:30 a.m. MST on April 28, 2005 at the Metropolitan Centre, 333 Fourth Avenue S.W., Calgary, Alberta. Presentations from the meeting will be web cast live at www.suncor.com.

Corporate Office

Box 38, 112 – 4th Avenue S.W., Calgary, Alberta, T2P 2V5
Telephone: 403-269-8100 Toll free number: 1-866-SUNCOR-1
Facsimile: 403-269-6217 E-mail: info@suncor.com

Analyst and Investor Inquiries

John Rogers, vice president, Investor Relations
Telephone: (403) 269-8670 Facsimile: (403) 269-6217 Email: invest@suncor.com

For further information, to subscribe or cancel duplicate mailings

In addition to annual and quarterly reports, Suncor publishes a biennial Report on Sustainability. All of Suncor's publications, as well as updates on company news as it happens, are available on our website at www.suncor.com. To subscribe to Suncor e-news, visit our website. To order copies of Suncor's print materials call 1-800-558-9071.

Sometimes our shareholders receive more than one copy of our Annual Report. If you receive but do not require more than one mailing, call Computershare Trust Company of Canada at 1-877-982-8760. Computershare will update your account information accordingly.

Shareholders can help reduce mailing costs and paper waste by electing to receive Suncor's Annual Report and other documents electronically. To register for electronic delivery, registered shareholders should visit www.computershare.com. Beneficial shareholders (shareholders holding shares through a broker) should go to www.investordeliverycanada.com and follow the instructions for enrollment.

corporate directors and officers

Providing strategic guidance to the company, setting policy direction and ensuring Suncor is fairly reporting its progress are central to the work of Suncor's Board of Directors.

The Board's oversight role encompasses Suncor's strategic planning process, risk management, communication with investors and other stakeholders and standards of business conduct. Suncor's Board is also responsible for selecting, monitoring and evaluating executive leadership and aligning management's decision making with long-term shareholder interest. There are no significant differences between Suncor's governance practices and those prescribed by the New York Stock Exchange (NYSE), with the exception of the requirements

applicable to equity compensation plans. A comprehensive description of Suncor's governance practices, including differences between Toronto Stock Exchange (TSX) and NYSE requirements related to equity compensation plans, is available in the company's Management Proxy Circular in the investor centre, financial reports and disclosure section of Suncor's website at www.suncor.com or by calling 1-800-558-9071.

Sarbanes-Oxley

For the year ended December 31, 2004, Suncor has voluntarily complied with the reporting, certification and attestation provisions under the United States Sarbanes-Oxley Act, Section 404.

Independence

As of December 31, 2004, Suncor's Board of Directors comprises thirteen directors, eleven of whom have been determined by the Board to be independent of management under the guidelines established by the TSX and NYSE. The role of chair is assumed by an independent director and is separate from the role of chief executive officer. Independent directors also chair the four committees of the Board.

Committee	Key Responsibilities
Board Policy, Strategy Review and Governance Committee*	Oversees key matters pertaining to Suncor's values, beliefs and standards of ethical conduct. Reviews key matters pertaining to governance, including organization, composition and effectiveness of the Board. Reviews preliminary stages of key strategic initiatives and projects. Reviews and assesses processes relating to long range and strategic planning and budgeting.
Human Resources and Compensation Committee*	Reviews and ensures Suncor's overall goals and objectives are supported by appropriate executive compensation philosophy and programs; annually evaluates the performance of the chief executive officer (CEO) against predetermined goals and criteria, and recommends to the Board the total compensation for the CEO. The committee also annually reviews the CEO's evaluation and recommendations for total compensation of the other executive roles; the executive succession planning process and results, and all major human resources programs.
Environment, Health and Safety (EH&S) Committee	Reviews the effectiveness with which Suncor meets its obligations pertaining to environment, health and safety including the establishment of appropriate policies with regard to legal, industry and community standards and related management systems and compliance.
Audit Committee*	Assists the Board in matters relating to Suncor's internal controls, internal and external auditors and the external audit process, oil and natural gas reserves reporting, financial reporting and public communication and certain other key financial matters. Provides an open avenue of communication between management, the internal and external auditors and the Board. Approves Suncor's interim financial statements and management's discussion and analysis.

*comprised entirely of independent directors as of December 31, 2004.

Share Ownership

The Board has set guidelines for its own, as well as executive share ownership. Shares held by each Board member and guidelines for Board and executive share ownership are reported annually in Suncor's Management Proxy Circular.

board of directors

JR Shaw (2),(3)
Calgary, Alberta
Chairman of the Board of Directors
Director since 1998
JR Shaw has been the chairman of the Board of Suncor since 2001. He is also the executive chair of Shaw Communications Inc., the company he founded in 1966. Mr. Shaw has served as a director of several Canadian companies and is also a director of the Shaw Foundation. In 2003, Mr. Shaw was named an Officer of the Order of Canada.

Mel E. Benson (3),(4)
Calgary, Alberta
Director since 2000
Mel Benson is president of Mel E. Benson Management Services Inc., an international management consulting firm based in Calgary, Alberta and a director of Pan Global Ventures Energy Ltd. From 1996 to 2000, Mr. Benson was the senior operations advisor, African Development, Exxon Co. International. Mr. Benson is an active member of several charitable and Aboriginal organizations. He is a member of the Council for Advancement of Native Development Officers and the Canadian Aboriginal Professional Association. He is also chair of the Northern Alberta Institute of Technology's Aboriginal Education Success Initiative.

Brian A. Canfield (2),(3)
Point Roberts, Washington
Chair, Human Resources and Compensation Committee
Director since 1995

Brian Canfield is the chairman of TELUS Corporation, a telecommunications company. Mr. Canfield also serves as a director of Terasen Inc. and a director and member of the governance committee of the Canadian Public Accountability Board. In 1998, Mr. Canfield was appointed to the Order of British Columbia.

Susan E. Crocker (2),(3)
Toronto, Ontario
Director 2003 to 2005
Susan Crocker, a director of Suncor since April 24, 2003, has advised the company she will not run for re-election to the Board. During her tenure with Suncor, Ms. Crocker was employed as a corporate director and management consultant. From 1999 to 2001, she was the president and chief executive officer of the Hospitals of Ontario Pension Plan and, from 1996 to 1999, she was senior vice president, equity and derivative markets with the TSX.

Bryan P. Davies (1),(4)
Toronto, Ontario
Director 1991 to 1996 and since 2000
Bryan Davies is superintendent of the Financial Services Commission of Ontario. Prior to assuming this role, Mr. Davies served as senior vice president of regulatory affairs with the Royal Bank Financial Group and was vice president, business affairs and chief administrative officer of the University of Toronto. He worked for the Government of Ontario holding a variety of positions, including deputy minister positions in several departments. Mr. Davies is also active with numerous not-for-profit and charitable organizations. He is chair of the Canadian Merit Scholarship Foundation and a director of the Foundation for International Training.

Brian A. Felesky (1),(4)
Calgary, Alberta
Director since 2002
Brian Felesky is a partner in the law firm of Felesky Flynn LLP in Calgary, Alberta. Mr. Felesky also serves as a director of TransCanada Power LP, where he is chair of the audit committee. Mr. Felesky is actively involved in not-for-profit and charitable organizations. He is the co-chair of Homefront on Domestic Violence, vice chair of the Canada West Foundation, member of the senate of Notre Dame College, member of the Board of Governors of the Council for Canadian Unity and a director of three private companies.

John T. Ferguson (1),(2)
Edmonton, Alberta
Chair, Audit Committee
Director since 1995
John Ferguson is chairman of the Board of Princeton Developments Ltd., a real estate company in Edmonton, Alberta, and chair 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. He is a director of the C.D. Howe Institute, an advisory member of the Canadian Institute for Advanced Research, and chancellor emeritus and chairman emeritus of the University of Alberta. Mr. Ferguson is also a fellow of the Alberta Institute of Chartered Accountants.

W. Douglas (Doug) Ford (1),(4)
Downers Grove, Illinois
Director since 2004
Doug Ford was chief executive, refining and marketing, for BP p.l.c. from 1998 to 2002 and was responsible for the refining, marketing and transportation network of the company as well as the aviation fuels business, the marine business and BP shipping. Mr. Ford currently serves as a director of USG Corporation, United Airlines Corporation and Air Products and Chemicals, Inc. He is also a member of the Board of Trustees of the University of Notre Dame.

Richard (Rick) L. George
Calgary, Alberta
Director since 1991
Rick George is the president and chief executive officer of Suncor Energy Inc. Mr. George is also a Board member of the U.S. offshore and onshore drilling company, GlobalSantaFe Corporation and serves as chairman of the Canadian Council of Chief Executives.

John R. Huff (2),(3)
Houston, Texas
Chair, Board Policy, Strategy Review and Governance Committee
Director since 1998
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 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 and as a trustee for the Houston Museum of Natural Science.

Robert W. Korthals (1)
Toronto, Ontario
Director since 1996
Robert Korthals is the former president of the Toronto-Dominion Bank. Mr. Korthals is currently chairman of the Board of the Ontario Teachers' Pension Plan Board. He is a director of Bucyrus International, Inc., Great Lakes Carbon Income Trust, Jannock Properties Limited, Rogers Communications Inc., easyHome Inc., Cognos Inc. and several publicly traded investment funds sponsored by Mulvihill Investments. In addition, Mr. Korthals serves as a director of the Canadian Parks and Wilderness Foundation.

M. Ann McCaig (3),(4)
Calgary, Alberta
Chair, Environment,
Health and Safety Committee
Director since 1995
Ann McCaig is chair of the Alberta Adolescent Recovery Centre and a trustee of the Killam Estate. She is co-chair of the Alberta Children's Hospital Foundation $50 million All for One – All for Kids campaign. Ms. McCaig has been an active member of the community with many local and national organizations including United Way, Banff Centre Foundation and chair of the City of Calgary Police Interpretative Centre. For 14 years she served on the University of Calgary's board of governors, was named chancellor, and in 1998, earned the distinction of chancellor emeritus. In 2005, Ms. McCaig was named a Member of the Order of Canada.

Michael W. O'Brien (4)
Canmore, Alberta
Director since 2002
Michael O'Brien served as executive vice president, Corporate Development and chief financial officer of Suncor Energy Inc. before his retirement 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 PrimeWest Energy Inc., Terasen Inc. and Shaw Communications Inc. As well, he is past chair for Canada's Climate Change Voluntary Challenge and Registry Inc., the Canadian Petroleum Products Institute and the Nature Conservancy Canada.

(1) Audit Committee
(2) Board Policy, Strategy Review and Governance Committee
(3) Human Resources and Compensation Committee
(4) Environment, Health and Safety Committee

In 2004, the Board of Directors met six times. Committees of the Board generally meet four to six times per year with the exception of the Audit Committee, which meets more frequently. With the exception of one Board member absent from one committee meeting, all members attended all board and committee meetings in 2004.

For further information about Suncor's corporate governance practices and the company's code of corporate conduct, visit www.suncor.com or call 1-800-558-9071 to order a copy of the company's Management Proxy Circular.

officers

Richard L. George
President and
Chief Executive Officer

J. Kenneth Alley
Senior Vice President
and Chief Financial Officer

M. (Mike) Ashar
Executive Vice President,
Refining and Marketing – U.S.A.

David W. Byler
Executive Vice President,
Natural Gas and Renewable Energy

Robert F. Froese
Treasurer

Terrence J. Hopwood
Senior Vice President
and General Counsel

Sue Lee
Senior Vice President, Human
Resources and Communications

Kevin D. Nabholz
Executive Vice President,
Major Projects

Janice B. Odegaard
Vice President, Associate General
Counsel and Corporate Secretary

Thomas L. Ryley
Executive Vice President, Energy
Marketing and Refining – Canada

Steven W. Williams
Executive Vice President,
Oil Sands

Offices shown are positions held by the officers in relation to business units of Suncor Energy Inc. and its subsidiaries on a consolidated basis. On a legal entity basis, Mr. Ashar is president of Suncor Energy (U.S.A.) Inc., Suncor's U.S. based downstream subsidiary; Mr. Ryley is president of Suncor's Canada-based downstream subsidiaries, Suncor Energy Marketing Inc. and Suncor Energy Products Inc.; and Mr. Nabholz is executive vice president of Suncor Energy Services Inc., which provides major projects management and other shared services to the Suncor group of companies.

The Dow Jones Sustainability Index (DJSI) follows a best-in-class approach comprising the sustainability leaders from each industry. Suncor has been part of the index since the DJSI was launched in 1999.

As an Imagine Caring Company, Suncor contributes 1% of its pretax profit to registered charities.

designed and produced by **smith** + associates

Suncor is committed to working in an environmentally responsible manner. The front section of this annual report is printed on paper containing 10% post-consumer waste and is acid free. The MD&A and financial sections are printed on paper containing 30% post-consumer waste and is acid-free.

Please recycle this annual report.

management's discussion and analysis

February 23, 2005

This Management's Discussion and Analysis (MD&A) 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 53 for additional information.

This MD&A should be read in conjunction with Suncor's audited Consolidated Financial Statements and the accompanying notes. All financial information is reported in Canadian dollars (Cdn$) and in accordance with Canadian generally accepted accounting principles (GAAP) unless noted otherwise. The financial measures cash flow from operations, return on capital employed and cash and total operating costs per barrel referred to in this MD&A, are not prescribed by GAAP and are outlined and reconciled in Non GAAP Financial Measures on page 51.

Certain prior years amounts have been reclassified to enable comparison with the current year's presentation.

Base operations refers to Oil Sands mining and upgrading operations.

Barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet (mcf) of natural gas : one barrel of crude oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

References to "Suncor" or "the company" mean Suncor Energy Inc., its subsidiaries and joint-venture investments, unless the context otherwise requires.

The tables and charts in this document form an integral part of this MD&A.

Additional information about Suncor filed with Canadian securities commissions and the United States Securities and Exchange Commission, including periodic quarterly and annual reports and the Annual Information Form (AIF/Form 40-F), is available on-line at www.sedar.com and www.sec.gov.

In order to provide shareholders with full disclosure relating to potential future capital expenditures, Suncor has provided cost estimates for projects that, in many cases, are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ and these differences may be material.

suncor overview and strategic priorities

Suncor Energy Inc. is an integrated energy company headquartered in Calgary, Alberta. The company operates four business segments:

- **Oil Sands** Suncor's core business unit, located near Fort McMurray, Alberta, produces bitumen recovered from oil sands and upgrades it to refinery feedstock, diesel fuel and byproducts.
- **Natural Gas** (NG) produces natural gas in Western Canada, providing revenues and serving as a price hedge against the company's purchased natural gas consumption.
- **Energy Marketing and Refining – Canada** (EM&R) operates a 70,000 barrel per day (bpd) capacity refinery in Sarnia, Ontario and markets refined petroleum products to customers primarily in Ontario and Quebec, including retail customers in Ontario under the Sunoco brand. (Sunoco in Canada is separate and unrelated to Sunoco in the United States, which is owned by Sunoco, Inc. of Philadelphia.) EM&R also manages Suncor's company-wide energy marketing and trading activities and sales of all Oil Sands and NG production. Financial results relating to the sales of Oil Sands and NG production are reported in those business segments.
- **Refining and Marketing – U.S.A.** (R&M) operates a 60,000 bpd capacity refinery in the Denver, Colorado area as well as related pipeline assets. R&M's retail network of 43 Phillips 66-branded stations operates primarily in the Denver area. In addition, the business has contract agreements with about 140 Phillips 66-branded outlets that operate throughout Colorado.

Suncor's strategic priorities are:

Operational:

- Developing Suncor's oil sands resource base through mining and in-situ technology and supplementing Suncor bitumen production with third-party supply.
- Expanding Oil Sands extraction and upgrading facilities to increase crude oil production.
- Integrating Oil Sands production into the North American energy market through Suncor's refineries and the refineries of other customers to reduce vulnerability to supply and demand imbalances.

- Managing environmental and social performance to earn continued stakeholder support for Suncor's ongoing operations and growth plans.
- Maintaining a strong focus on worker, contractor and community safety as an overriding operational priority.

Financial:

- Controlling costs through a strong focus on operational excellence, economies of scale and improved management of engineering, procurement and construction of major projects.
- Reducing risk associated with natural gas price volatility by producing natural gas volumes that meet or exceed purchases.
- Maintaining a strong balance sheet by controlling debt and closely managing capital cost outlays.
- Targeting opportunities that support a minimum 15% return on capital employed (ROCE) at US$28 West Texas Intermediate (WTI) crude oil prices and a Cdn$/US$ exchange rate of $0.75.

Significant Developments in 2004 and Subsequent Event

- Suncor's common shares closed at $42.40 at the end of 2004, an increase of 30% over 2003. Suncor shares outperformed the S&P 500 Index during the year.
- Total production increased to 263,300 barrels of oil equivalent per day (boe/d), from 251,500 boe/d in 2003.
- Production at Suncor's Oil Sands facility averaged 226,500 bpd, comprising 215,600 bpd from base operations and 10,900 bpd of bitumen from the company's in-situ operations. Production in 2003 averaged 216,600 bpd; there was a 30-day planned maintenance shutdown and no in-situ production that year.
- Cash operating costs from Oil Sands base operations averaged $11.95 per barrel during 2004, at an average natural gas price of US$6.20 per thousand cubic feet.
- Natural gas production increased to 200 million cubic feet per day (mmcf/d) in 2004, compared to 187 mmcf/d in 2003.
- Refining margins averaged 8.0 cents per litre (cpl) for Canadian operations and 6.7 cpl for U.S. operations. This compares to 6.5 cpl for Canadian operations and 5.9 cpl for U.S. operations during 2003. Retail gasoline margins averaged 4.4 cpl for Canadian operations and 5.4 cpl for U.S. operations compared to 6.6 cpl for Canadian operations and 5.6 cpl for U.S. operations the year before.
- During 2004, work to expand Oil Sands productioncapacity to 260,000 bpd continued on schedule andon budget. Suncor also began preliminary site work and vessel construction for projects planned to increase production capacity to 350,000 bpd in 2008.
- In 2004, expansion and upgrades of the company's Sarnia and Denver refineries were launched.
- While Suncor invested $1.8 billion in capital spending primarily to expand operations, maintaining a strong balance sheet remained a priority. At December 31, 2004, Suncor's net debt (including cash and cash equivalents) was approximately $2.2 billion, compared to $2.1 billion at December 31, 2003. Including preferred securities, net debt at December 31, 2003 was $2.6 billion. These securities were redeemed in 2004.
- Suncor achieved a company-wide return on capital employed of 19.1% (excluding major projects in progress).
- In January 2005, a fire at Oil Sands damaged Upgrader 2. As a result, production at Oil Sands is expected to be reduced until the third quarter (see page 21).

selected financial information

Annual Financial Data

Year ended December 31 ($ millions except per share data)	2004	2003	2002
Revenues	**8 621**	6 571	5 032
Net earnings	**1 100**	1 075	749
Total assets	**11 804**	10 501	9 011
Long-term debt	**2 217**	2 448	2 686

Dividends			
Common shares	**103**	87	77
Preferred securities	**9**	45	48
Net earnings attributable to common shareholders per share – basic	**2.40**	2.41	1.61
Net earnings attributable to common shareholders per share – diluted	**2.36**	2.24	1.58
Cash dividends per share	**0.23**	0.19	0.17

Outstanding Share Data

As at December 31, 2004 (thousands)	
Number of common shares	454 241
Number of common share options	20 687
Number of common share options – exercisable	9 067

Quarterly Financial Data

	2004 Quarter ended				2003 Quarter ended			
($ millions except per share)	**Dec. 31**	**Sept. 30**	**June 30**	**Mar. 31**	**Dec. 31**	**Sept. 30**	**June 30**	**Mar. 31**
Revenues	**2 310**	**2 315**	**2 201**	**1 795**	1 698	1 788	1 385	1 700
Net earnings	**333**	**337**	**203**	**227**	302	291	116	366
Net earnings attributable to common shareholders per share								
Basic	**0.73**	**0.74**	**0.44**	**0.48**	0.67	0.63	0.27	0.84
Diluted	**0.72**	**0.73**	**0.43**	**0.46**	0.62	0.61	0.24	0.77

Net Earnings(1)
($ millions)



	04	**03**	**02**
Oil Sands	**995**	888	782
Natural Gas	**115**	120	34
Energy Marketing and Refining – Canada	**80**	53	61
Refining and Marketing – U.S.A.(3)	**34**	18	—

Capital Employed(1) (2)
($ millions)



	04	**03**	**02**
Oil Sands	**4 169**	4 050	4 512
Natural Gas	**448**	400	422
Energy Marketing and Refining – Canada	**512**	551	485
Refining and Marketing – U.S.A.(3)	**232**	270	—

Cash Flow from Operations (1)
($ millions)



	04	**03**	**02**
Oil Sands	**1 752**	1 803	1 475
Natural Gas	**319**	298	164
Energy Marketing and Refining – Canada	**188**	164	112
Refining and Marketing – U.S.A.(3)	**59**	34	—

(1) Excludes Corporate and Eliminations segment.
(2) Excludes major projects in progress.
(3) Refining and Marketing – U.S.A. 2003 data reflects five months of operations since acquisition on August 1, 2003.

Quarterly net earnings for 2004 and 2003 fluctuated due to a number of factors:

- U.S. dollar denominated crude oil prices were higher on average in 2004 compared to 2003.
- Oil Sands Alberta Crown royalties increased significantly during 2004 as a result of a modification in the Province of Alberta's royalty classification for Firebag in-situ operations and higher crude oil prices (see page 24).
- The impact of scheduled and unscheduled maintenance at Oil Sands (including in-situ operations) reduced production during 2004. In the second quarter of 2003, there was a planned 30-day maintenance shutdown on Upgrader 1 that reduced production capacity during that period.
- Cash operating costs fluctuated due to the factors impacting Oil Sands production and the price and purchased volume of natural gas used for energy in Oil Sands operations.
- Commodity and refined product prices fluctuated as a result of global and regional supply and demand, as well as seasonal demand variations. In the downstream, seasonal fluctuations were reflected in higher demand for vehicle fuels and asphalt in summer and heating fuels in winter.
- Realized commodity prices were unfavourably impacted in 2004 and 2003 by increases in the Canadian dollar compared to the U.S. dollar, which reduced the Canadian dollar revenue earned. The stronger Canadian dollar also resulted in net foreign exchange gains on U.S. dollar denominated debt in 2004 and 2003. These gains were higher in 2003 due to the greater appreciation of the Canadian dollar during 2003 compared to 2004.
- A 1% reduction in the Province of Alberta's corporate tax rates in the first quarter of 2004 increased 2004 net earnings by $53 million. In 2003, changes to federal taxation policies relating to the resource sector and changes to both the Alberta and Ontario provincial tax rates reduced 2003 net earnings by $89 million.

Consolidated Financial Analysis

This analysis provides an overview of Suncor's consolidated financial results for 2004 compared to 2003. For a detailed analysis, see the various business segment analyses.

Net Earnings

Suncor's net earnings were $1.1 billion in 2004, compared with $1.075 billion in 2003 (2002 – $749 million). The increase was primarily due to higher U.S. dollar benchmark crude oil prices (net of widening light/heavy crude oil differentials), increased production, and non-cash reductions in income tax expense due to year-over-year changes in tax rates and resource allowance deductions. These positive impacts were largely offset by higher Oil Sands Alberta Crown royalties, higher crude oil hedging losses and the impact of a stronger Canadian dollar.

Net Earnings Components (1)

Year ended December 31 ($ millions, after tax)	2004	2003	2002
Net earnings before the following items:	**1 248**	1 048	718
Firebag in-situ start-up costs	**(14)**	—	—
Oil Sands Alberta Crown royalties	**(261)**	(21)	(22)
Impact of income tax rate reductions on opening net future income tax liabilities	**53**	(89)	10
Unrealized foreign exchange gains on U.S. dollar denominated long-term debt	**74**	137	8
Sale of retail natural gas marketing business	**—**	—	35
Net earnings as reported	**1 100**	1 075	749
Net earnings attributable to common shareholders as reported	**1 088**	1 085	722

(1) This table explains some of the factors impacting Suncor's after-tax net earnings. For comparability purposes, readers should rely on the reported net earnings that are prepared and presented in the company's consolidated financial statements and notes in accordance with Canadian GAAP.

Industry Indicators

(Average for the year unless otherwise noted)	2004	2003	2002
West Texas Intermediate (WTI) crude oil US$/barrel at Cushing	**41.40**	31.05	26.10
Canadian 0.3% par crude oil Cdn$/barrel at Edmonton	**52.55**	43.55	40.75
Light/heavy crude oil differential US$/barrel WTI at Cushing less Bow River at Hardisty	**12.80**	8.00	5.95
Light/heavy crude oil differential US$/barrel WTI at Cushing less Lloyd Light Blend at Hardisty	**13.55**	8.65	6.55
Natural gas US$/thousand cubic feet (mcf) at Henry Hub	**6.20**	5.45	3.25
Natural gas (Alberta spot) Cdn$/mcf at AECO	**6.80**	6.70	4.05
New York Harbour 3-2-1 crack US$/barrel (1)	**6.90**	5.30	3.35

Refined product demand (Ontario) percentage change over prior year (2)	**4.3**	2.5	0.6
Exchange rate: Cdn$/US$	**0.77**	0.72	0.64

(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) Figures for 2002 and 2003 are based on published government data. Figures for 2004 are internal estimates based on preliminary government data.

Revenues were $8.6 billion in 2004, compared with $6.6 billion in 2003 (2002 – $5.0 billion). The increase resulted primarily from the following:

- Average commodity prices were higher in 2004 than in 2003. A 33% increase in average U.S. dollar WTI benchmark pricing increased the selling price of Oil Sands crude oil production. Mitigating this increase, average light/heavy crude oil differentials compared to the WTI benchmark index widened approximately 60%. As a result, the net price Suncor received on certain sour crude oil and bitumen sales did not increase by as much as the increase in WTI.

- In 2004, Oil Sands sales averaged 226,300 bpd, compared with 218,300 bpd in 2003 (2002 – 205,300 bpd). Increased crude oil production drove higher sales volumes. Oil Sands sales in 2004 included production of 10,900 bpd of bitumen from Firebag in-situ operations, which commenced operations during the year. Overall sales volumes in 2004 were lower than anticipated due to the effects of unplanned maintenance at both the base plant and in-situ operations. In 2003, sales volumes were negatively impacted by a planned 30-day maintenance shutdown.

- Refined product wholesale and retail prices in both EM&R and R&M were higher due to higher crude oil feedstock prices. In addition, a 3% increase in refined product sales volumes in EM&R had a positive impact on revenue.

- R&M revenues increased as a result of one full year of operations, compared to five months in 2003 (R&M was acquired on August 1, 2003).

Partially offsetting these increases were the following:

- A 7% increase in the average Cdn$/US$ exchange rate resulted in lower realizations on Suncor's crude oil sales basket and natural gas sales. Because crude oil and natural gas are primarily sold based on U.S. dollar benchmark prices, a narrowing of the exchange rate difference reduced the Canadian dollar value of Suncor's products.

- Higher strategic crude oil hedging losses decreased revenues. During 2004, Suncor sold a portion of its crude oil production at fixed prices that were lower than prevailing market prices. After-tax hedging losses in 2004 were $397 million compared to $155 million in 2003.

Overall, higher prices, net of the impact of the higher Cdn$/US$ exchange rate, increased total revenues by approximately $1.2 billion. Higher volumes increased revenues by approximately $220 million and the impact of 12 months of R&M results compared to five months in 2003 increased revenues by approximately $980 million. These impacts were partially offset by hedging losses, which reduced revenues by approximately $380 million.

Purchases of crude oil and crude oil products were $2.9 billion in 2004 compared with $1.7 billion in 2003 (2002 – $1.2 billion). The increase was primarily due to the following:

- Higher benchmark crude oil feedstock prices, which increased purchases by approximately $360 million.

- Higher feedstock requirements as a result of one full year of operations for R&M, compared to five months in 2003, increased purchases by approximately $830 million.

- The repurchase of crude oil originally sold to a Variable Interest Entity (VIE) in 1999 increased purchases at Oil Sands in the second quarter by approximately $55 million.

- The 3% increase in refined product sales in EM&R required the purchase of higher volumes of feedstock and refined products.

Operating, selling and general expenses were $1.8 billion in 2004 compared with $1.5 billion in 2003 (2002 – $1.3 billion). The primary reasons for the increase were:

- The effects of 12 months of operations at R&M in 2004 compared to only five months of operations in 2003.

- The first year of in-situ operations.

- Higher operating expenses, including higher energy costs in all businesses.

- Increased maintenance activities due to scheduled maintenance at the R&M Denver refinery and the EM&R Sarnia refinery as well as unscheduled maintenance at Oil Sands base plant and in-situ operations, and the EM&R Sarnia refinery.

- Corporate costs related to the company's enterprise resource planning (ERP) implementation project as well as costs related to obtaining

certification under the Sarbanes-Oxley Act, Section 404.

- Higher stock-based compensation expense, primarily due to the achievement of certain performance based vesting conditions under the company's SunShare stock option plan and an increase in the overall number of stock options being expensed.

Transportation and other expenses remained relatively constant at $132 million in 2004 compared to $135 million in 2003 (2002 – $128 million). Increased transportation costs of $13 million in R&M due to a full year of operations, were offset by mark-to-market gains on inventory-related derivatives in Oil Sands. Consistent with 2003, Oil Sands pipeline tolls continued to be reduced by initial shipper toll adjustments. Oil Sands initial shipper toll adjustments are currently expected to continue until at least 2007.

Depreciation, depletion and amortization (DD&A) was $717 million in 2004 compared with $618 million in 2003 (2002 – $595 million). DD&A at Oil Sands increased by $45 million due to higher overburden amortization, higher maintenance shutdown and catalyst amortization, and depletion incurred in in-situ operations, which commenced in 2004. NG depletion increased by $24 million, reflecting higher production levels and a higher depletion base. Higher depreciation and amortization of $16 million associated with 12 months of operations in R&M also contributed to the increase.

Exploration expenses were $55 million in 2004, largely unchanged from $51 million in 2003 (2002 – $26 million). Decreased NG dry hole expenses of $11 million in 2004 were offset by higher seismic expenses in NG and higher core hole drilling activity in Oil Sands.

Royalty expenses were $531 million in 2004 compared with $139 million in 2003 (2002 – $98 million). The significant increase in 2004 was primarily related to increased Alberta Crown royalties at Oil Sands. For a further discussion about Oil Sands Crown royalties, see page 24. Royalties in NG also increased by $18 million due to higher realized natural gas prices and higher production volumes.

Taxes other than income taxes were $496 million in 2004 compared to $426 million in 2003 (2002 – $374 million). The increase was primarily due to additional excise taxes related to R&M operations.

Financing expenses were $9 million in 2004 compared with income of $66 million in 2003 (2002 – expense of $124 million). The increase in expenses was primarily due to $77 million of lower foreign exchange gains on the company's U.S. dollar denominated long-term debt. Interest expense net of capitalized interest was $87 million in 2004, compared to $83 million in 2003. The relatively unchanged interest expense net of capitalized interest was a result of reasonably stable levels of long-term debt, effective interest rates and average balances of major projects in progress.

Income tax expense was $536 million in 2004 (33% effective tax rate), compared with $726 million in 2003 (40% effective tax rate) (2002 – $378 million – 33% effective tax rate). Income tax expense in both 2004 and 2003 included the effects of adjustments to opening future income tax balances due to changes in tax rates that reduced tax expense by $53 million in 2004 and increased tax expense by $89 million in 2003. Excluding these adjustments, income tax expense in 2004 was $589 million (36% effective tax rate) compared to $637 million in 2003 (35% effective tax rate). The higher effective rate in 2004 was primarily due to the tax effect of lower foreign exchange gains on long-term debt in 2004 compared to 2003.

Corporate Expenses

After-tax corporate expenses were $124 million in 2004 compared to $4 million in 2003 (2002 – $128 million). The increase was due to higher financing costs and higher operating, selling and general expenses (discussed above).

The corporate office had a net cash deficiency of $334 million in 2004, compared with $235 million in 2003 (2002 – $225 million). The increased deficiency was primarily due to the same factors that increased operating, selling and general expenses, as well as changes in working capital.

Consolidated Cash Flow from Operations

Cash flow from operations was $2.02 billion in 2004 compared to $2.08 billion in 2003 (2002 – $1.44 billion). Excluding the impacts of foreign exchange gains and non-cash future income tax expense, cash flow was primarily impacted by the same factors affecting net earnings. In addition, higher cash overburden spending in 2004 reduced cash flow from operations by $47 million compared to 2003.

Dividends

In the second quarter of 2004, Suncor's Board of Directors approved an increase in the quarterly dividend to $0.06 per share, from $0.05 per share. Total dividends paid during 2004 were $0.23 per share, compared with $0.1925 per share in 2003. The Board periodically reviews the dividend policy, taking into consideration Suncor's capital spending profile, financial position, financing requirements, cash flow and other relevant factors.

Subsequent Event

On January 4, 2005, a fire at Oil Sands damaged Upgrader 2. As a result, production at Oil Sands base operations was reduced to about 110,000 bpd. Repairs are expected to take several months and Suncor does not expect to return to full capacity of 225,000 bpd until the third quarter of 2005.

The company carries property loss and business interruption insurance policies with a combined coverage limit of up to US$1.15 billion, net of deductible amounts, that will mitigate, upon receipt of these funds, a portion of the financial impact of this incident. The primary property loss policy of US$250 million has a deductible per incident of US$10 million and the primary business interruption policy of US$200 million has a

deductible per incident of the greater of US$50 million gross earnings lost (as defined in the insurance policy) or 30 days from the incident. In addition to these primary coverage insurance policies, Suncor has excess coverage of US$700 million that can be used for either property loss or business interruption coverage. For business interruption purposes, this excess coverage begins on the later of full utilization of the primary business interruption coverage or 90 days from the date of the incident. For accounting purposes, the company will accrue insurance proceeds up to the net book value of the damaged assets. Proceeds in excess of this amount, as well as business interruption proceeds, will be recorded when unconditionally settled.

As the company is still evaluating the effect of the fire on its operations, the financial impact of this incident cannot currently be determined.

The impact on liquidity and capital resources is described in more detail below.

Liquidity and Capital Resources

Suncor's capital resources at December 31, 2004 consisted primarily of cash flow from operations and available lines of credit. Suncor's level of earnings and cash flow from operations depend on many factors, including commodity prices, production levels, downstream margins related to the operations of EM&R and R&M and Cdn$/US$ exchange rates. In 2005, cash flow from operations will be negatively impacted by the upgrader fire in Oil Sands.

At December 31, 2004, Suncor's net debt (short and long-term debt less cash and cash equivalents) was approximately $2.2 billion compared to $2.1 billion at December 31, 2003. Including preferred securities, net debt was $2.6 billion at December 31, 2003. In February 2004, Suncor repaid all $125 million of its then outstanding 7.4% debentures. In March 2004, the company redeemed its 9.05% and 9.125% preferred securities for cash consideration of $493 million. Approximately $300 million of the reduction in total net debt, including preferred securities in 2004, was generated from cash flow with the balance attributable to foreign exchange gains.

In 2004, Suncor renewed its available credit facilities of approximately $1.7 billion. Suncor's undrawn lines of credit at December 31, 2004, were approximately $1.5 billion. Suncor's current long-term senior debt ratings are A- by Standard & Poor's, A(low) by Dominion Bond Rating Service and A3 by Moody's Investors Service. All debt ratings have a stable outlook.

In 2000, Suncor entered into a financing arrangement with a third-party, whereby Suncor sold an undivided interest in Oil Sands energy services assets for $101 million and leased the assets back from the third-party. Suncor repurchased the assets in December 2004 with financing through existing revolving credit facilities. Since this lease was capitalized for accounting purposes, it was included in Suncor's debt at the end of 2003.

Interest expense on debt continues to be influenced by the composition of the company's debt portfolio, with Suncor benefiting from short-term floating interest rates

continuing at low levels. To manage fixed versus floating rate exposure, Suncor has entered into interest rate swaps with investment grade counterparties, resulting in the swapping of $600 million of fixed rate debt to variable rate borrowings.

Management of debt levels continues to be a priority given Suncor's growth plans. The company believes a phased approach to existing and future growth projects should maintain its ability to manage project costs and debt levels.

Suncor believes it has the capital resources to fund its 2005 capital spending program of $2.5 billion and to meet current working capital requirements, notwithstanding the impact of the fire at Oil Sands on cash flow from operations and the cost to repair damaged facilities. However, the time required for Suncor's Oil Sands facilities to return to full production, and the timing of receipts of the insurance proceeds may significantly impact Suncor's capital resources and consequently Suncor's financing plan will be reviewed throughout 2005. If additional capital is required, the company believes adequate additional financing is available at commercial terms and rates.

Suncor anticipates its growth plan to be largely financed from internal cash flow, which is dependent on commodity prices and other factors. After 2005, to support its growth strategy and sustain operations, Suncor is projecting an annual capital spending program of approximately $2.3 billion to $2.5 billion that will continue for the foreseeable future. Actual spending is subject to change due to such factors as internal and external approvals and capital availability. Refer to the discussion under Risk/Success Factors Affecting Performance on page 25 for additional factors that can have an impact on Suncor's ability to generate funds to support investing activities.

Aggregate Contractual Obligations and Off-balance Sheet Financing

	Payments Due by Period				
($ millions)	**Total**	**2005**	**2006-07**	**2008-09**	**Later Years**
Fixed-term debt, commercial paper and capital leases (1)	2 217	91	405	3	1 718
Interest payments on fixed-term debt, commercial paper and capital leases (1)	2 544	141	264	229	1 910
Employee future benefits (2)	441	31	70	80	260
Asset retirement obligations (3)	1 079	47	87	57	888
Non-cancellable capital spending commitments (4)	157	157	—	—	—
Operating lease agreements, pipeline capacity and energy services commitments (5)	4 798	222	438	458	3 680
Total	**11 236**	**689**	**1 264**	**827**	**8 456**

In addition to the enforceable and legally binding obligations quantified in the above table, the company has other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice. Commodity purchase obligations

for which an active, highly liquid market exists and which are expected to be re-sold shortly after purchase, are one example of excluded items.

(1) Includes $2,104 million of U.S. and Canadian dollar denominated debt that is redeemable at the option of the company. Maturities range from 2007 to 2034. Interest rates vary from 5.95% to 7.15%. The company entered into various interest rate swap transactions maturing in 2007 and 2011 that resulted in an average effective interest rate in 2004 ranging from 3.5% to 4.3% on $600 million of the company's medium-term notes. Approximately $89 million of commercial paper with an effective interest rate of 2.3% was issued in 2004.

(2) Represents the undiscounted expected benefit payments to retirees for pension and other post-employment benefits.

(3) Represents the undiscounted amount of legal obligations associated with site restoration on the retirement of assets with determinable useful lives.

(4) Non-cancellable capital commitments related to capital projects totalled approximately $157 million at the end of 2004. The grouping of commitments outstanding is associated with the Firebag in-situ development ($48 million), expanded production facilities at Oil Sands ($27 million), and desulphurization projects at the company's refineries ($82 million).

(5) Includes transportation service agreements for pipeline capacity and tankage for the shipment of crude oil from Fort McMurray to Hardisty, Alberta, as well as energy services agreements to obtain a portion of the power and steam generated by a cogeneration facility owned by a major energy company. Non-cancellable operating leases are for service stations, office space and other property and equipment.

The company is subject to financial and operating covenants related to its public market and bank debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as described in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations.

In addition, a very limited number of the company's commodity purchase agreements, off-balance sheet arrangements and derivative financial instrument agreements, contain provisions linked to debt ratings that may result in settlement of the outstanding transactions should the company's debt ratings fall below investment grade status.

At December 31, 2004, the company was in compliance with all material covenants and its debt ratings were investment grade with a stable outlook. For more information, see page 21.

Variable Interest Entities and Guarantees

At December 31, 2004, the company had off-balance sheet arrangements with Variable Interest Entities (VIEs), and indemnification agreements with other 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, 2004, $170 million in outstanding accounts receivable had been sold under the program. Under the recourse provisions, the company will provide indemnification against credit losses for certain counterparties, which did not exceed $50 million in 2004. A liability has not been recorded for this indemnification as the company believes it has no significant exposure to credit losses. There were no new securitization proceeds in 2004. Proceeds from collections reinvested in securitizations on a revolving basis for the year ended December 31, 2004, were approximately $2,073 million. The company recorded an after-tax loss of approximately $2 million on the securitization program in 2004 (2003 and 2002 – $3 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 as at December 31, 2004, was 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 a specified date in 2005. Had the company elected to terminate the lease at December 31, 2004, the total cost would have been $25 million. Annualized equipment lease payments in 2004 were $6 million (2003 – $4 million; 2002 – $2 million). This VIE was consolidated effective January 1, 2005.

The company has agreed to indemnify holders of the 7.15% fixed-term U.S. dollar notes, the 5.95% fixed-term U.S. dollar notes and the company's credit facility lenders 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, 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 regulationsand 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.

Outlook

During 2005, management will focus on the following operational priorities:

- Complete fire recovery and planned maintenance at Oil Sands to return to full production in the third quarter.
- Increase natural gas production volumes to 205 to 210 mmcf/d. Suncor will continue to focus on high impact natural gas plays and work to

achieve an annual target of 3% to 5% production growth. For more information, see page 43.

- Build for future Oil Sands growth. Expansion projects to increase Oil Sands production capacity to 260,000 bpd are expected to be complete by the end of 2005. Work to bring production capacity to 350,000 bpd in 2008 is also expected to reach several milestones with fabrication and transport of major vessels planned to be completed in 2005. In planning for expansion beyond 2008, Suncor expects to file a regulatory application in 2005 to construct a third upgrader, a key step towards increasing production capacity to 500,000 to 550,000 bpd in the 2010 to 2012 time frame. For more information, see page 39.

- Focus on enterprise-wide efficiency. To more seamlessly integrate Suncor's operations and prepare for future growth, the company is implementing a company-wide ERP information and management system.

- Advance downstream integration plans. Suncor will reach peak activity on modifications to the Sarnia and Denver refineries to meet 2006 low-sulphur diesel regulations and integrate increased volumes of oil sands production in both refineries. For more information, see pages 47 and 50.

Oil Sands Crown Royalties and Cash Income Taxes

Crown royalties in effect for Oil Sands operations require payments to the Government of Alberta, based on gross revenues less related transportation costs (R), less allowable costs (C), including the deduction of certain capital expenditures (the 25% R-C royalty), subject to a minimum payment of 1% of R. In April 2004, the Alberta government confirmed it would modify Suncor's royalty treatment because it does not recognize the company's Firebag in-situ facility as an expansion to the company's existing Oil Sands Project. Accordingly, for Alberta Crown royalty purposes, Suncor's oil sands operations are considered two separate projects: base oil sands mining and associated upgrading operations with royalties based on upgraded product values and the current Firebag in-situ project with royalties based on bitumen values. On this basis, Suncor has provided for estimated pretax Alberta Oil Sands Crown royalties in 2004 of $407 million. Alberta Oil Sands Crown royalties may be subject to change as policies arising from the Government's position are finalized and audits of the 2004 and prior years are completed. Changes to the estimated amounts previously recorded will be reflected in the company's financial statements on a prospective basis and may be significant.

In July, Suncor issued a statement of claim against the Crown, seeking, among other things, to overturn the government's decision on the royalty treatment of Firebag. The Crown has issued a statement of defence. To date, there have been no significant further developments with respect to these legal proceedings.

Alberta Crown royalties payable in 2005 and subsequent years continue to be highly sensitive to, among other factors, changes in crude oil and natural gas pricing, foreign exchange rates, and total capital and operating costs for each Project. In addition, 2004 was a transition year for Oil Sands as the remaining amount of prior years' allowable costs carried forward of approximately $600 million were claimed in 2004 to reduce the company's 2004 Alberta Crown royalty obligation. No such carryforward of allowed costs exists for 2005 and subsequent years.

Assuming anticipated levels of operating expenses and capital expenditures for each Project remain relatively constant, variability in expected Oil Sands royalty expense is primarily a function of changes in expected annual Oil Sands revenue. Absent the impact of the January 4th, 2005 fire, the company expected that Alberta Oil Sands Crown royalty expense for the period 2005 to 2007 would range from approximately 12% to 14% of total Oil Sands Revenue based on WTI prices of US$40 to US$50 respectively. For subsequent years, this percentage range may decline as anticipated new in-situ production attracts royalties based on bitumen values. This royalty percentage range is based on the following assumptions: a natural gas price of US$6.25 per mcf at Henry Hub; a light/heavy oil differential to the U.S. Gulf Coast of US$9 per barrel; and a Cdn$/US$ exchange rate of 0.80.

Alberta Oil Sands Crown royalty expense in 2005 and 2006 may be significantly impacted by the amount and timing of the recognition of the business interruption insurance proceeds. Accordingly, the range of annualized royalty expense as a percentage of revenues, may differ from that stated above, and these differences may be material.

Based on the company's current long-term planning assumptions, the 25% R-C royalty would continue to apply to the existing Oil Sands base operations in future years and the 1% minimum royalty would apply to the Firebag project until the next decade. The company continues to discuss the terms of Suncor's option to transition to the generic bitumen-based royalty regime in 2009. After 2009 the royalty would be based on bitumen value if Suncor exercised its option to transition to the Province of Alberta's generic regime for oil sands royalties. In the event that Suncor exercises this option, future upgrading operations would not be included for Oil Sands royalty purposes.

The timing of when the Oil Sands operation will be fully cash taxable is highly dependent on crude oil commodity prices and capital invested. At prices between US$34 and US$50 per barrel WTI, an average annual Cdn$/US$ foreign exchange rate of $0.80, future investment plans and certain other assumptions, Suncor does not believe it will be fully cash taxable until the next decade. However, in any particular year, the company's Oil Sands and NG operations may be subject to some cash income tax due to the sensitivity to crude oil and natural gas commodity price volatility and the timing of recognition of capital expenditures for tax purposes. Based on the assumptions stated above, the company anticipates that Oil Sands and NG operations will be partially cash taxable commencing in 2009 at US$34 per barrel WTI, and in 2007 at US$40 to US$50 per barrel WTI, until the next decade, at which point it is expected to become fully cash taxable.

The information in the preceeding paragraphs under Oil Sands Crown Royalties and Cash Income Taxes incorporates operating and capital cost assumptions included in the company's current budget and long-range plan, and is not an estimate, forecast or prediction of actual future events or circumstances.

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. The company currently estimates that in 2010 the impact of the Kyoto Protocol on Oil Sands cash operating costs would be an increase of about $0.20 to $0.27 per barrel. This estimate assumes a reduction obligation of 15% from 2010 business-as-usual energy intensity(1) and that the maximum price for carbon credits would, as the Government of Canada indicated in 2002, be capped at $15 per tonne of carbon dioxide equivalent until 2012. Based on these assumptions, Suncor does not currently anticipate that the cost implications of federal and provincial climate change plans will have a material impact on its business or future growth plans.

The ultimate impact of Canada's 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.

Risk/Success Factors Affecting Performance

Suncor's financial and operational performance is potentially affected by a number of factors including, but not limited to, commodity prices and exchange rates, environmental regulations, stakeholder support for growth plans, extreme winter weather, regional labour issues and other issues discussed within Risk/Success Factors for each Suncor business segment. A more detailed discussion of risk factors is presented in the company's most recent AIF/40-F, filed with securities regulatory authorities.

Commodity Prices, Refined Product Margins and Exchange Rates

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, seasonality, worldwide political events and weather. These factors, among others, can result in a high degree of price volatility. For example, from 2002 to 2004 the monthly average price for benchmark WTI crude oil ranged from a low of US$19.70 per barrel to a high of US$53.10 per barrel. During the same three-year period, the natural gas Henry Hub benchmark monthly average price ranged from a low of US$2.00 per mcf to a high of US$9.30 per mcf. Suncor believes commodity price volatility will continue.

Crude oil and natural gas prices are based on U.S. dollar benchmarks that result in Suncor's realized prices being influenced by the Cdn$/US$ currency exchange rate, thereby creating an element of uncertainty for the company. Should the Canadian dollar strengthen compared to the U.S. dollar, the negative effect on net earnings would be partially offset by foreign exchange gains on the company's U.S. dollar denominated debt. Conversely, should the Canadian dollar weaken compared to the U.S. dollar, the positive effect on net earnings would be partially offset by foreign exchange losses on the company's U.S. dollar denominated debt. Cash flow from operations is not impacted by the effects of currency fluctuations on the company's U.S. dollar denominated debt.

Changes to the Cdn$/US$ exchange rate relationship can create significant volatility in foreign exchange gains or losses. On the outstanding US$1 billion in U.S. dollar denominated debt at the end of 2004, a $0.01 change in the Cdn$/US$ exchange rate would change earnings by approximately $12 million after tax.

During 2004, the strengthening of the Canadian dollar against the U.S. dollar resulted in a $74 million after tax foreign exchange gain on the company's U.S. dollar denominated debt.

Suncor's U.S. capital projects are expected to be partially funded from Canadian operations. A weaker Canadian dollar would result in a higher funding requirement for these projects.

(1) Reflects the level of greenhouse gas emissions that would have occurred in the absence of energy efficiency and process improvements after 2000.

Sensitivity Analysis (1)

	2004 Average		Change	Approximate Change in Cash Flow from Operations	Approximate Change in After-tax Earnings
Oil Sands					
Price of crude oil ($/barrel) (2)	$ 42.28	US$	1.00	43	28
Sweet/sour differential ($/barrel)	$ 8.65	US$	1.00	32	20
Sales (bpd)	226 300		1 000	10	7
Natural Gas					

Price of natural gas ($/mcf) (2)	$	6.70	0.10	6	3
Production of natural gas (mmcf/d)		200	10	16	7
Energy Marketing and Refining – Canada					
Retail gasoline margins (cpl)		4.4	0.1	2	1
Refining/wholesale margin (cpl) (2)		8.0	0.1	6	4
Refining and Marketing – U.S.A.					
Retail gasoline margins (cpl)		5.4	0.1	—	—
Refining/wholesale margin (cpl)		6.7	0.1	3	2
Consolidated					
Exchange rate: Cdn$/US$		0.77	0.01	33	10

(1) The sensitivity analysis shows the main factors affecting Suncor's annual cash flow from operations and after-tax earnings based on actual 2004 operations. The table illustrates the potential financial impact of these factors applied to Suncor's 2004 results. A change in any one factor could compound or offset other factors.
(2) Includes the impact of hedging activities.

Derivative Financial Instruments

The company periodically enters into commodity-based derivative financial instruments such as forwards, futures, swaps and options to hedge against the potential adverse impact of changing market prices due to variations in underlying commodity indices. 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.

The company also uses energy derivatives, including physical and financial swaps, forwards and options to gain market information and to earn trading revenues. These trading activities are accounted for at fair value in the company's consolidated financial statements.

Derivative contracts accounted for as hedges are not recognized in the Consolidated Balance Sheets. Realized and unrealized gains or losses on these contracts, including realized gains and losses on derivative hedging 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.

Commodity Hedging Activities Suncor's strategic crude oil hedging program has been the subject of periodic management reviews to determine the continued need for hedging in light of the company's tolerance for exposure to market volatility, as well as its need for stable cash flow to finance future growth. In the first quarter of 2004, Suncor's Board of Directors suspended the company's strategic crude oil hedging program. As a result, the company did not enter into any new strategic crude oil arrangements in 2004. The strength of the company's financial position, combined with stable operating costs and a growing production base, reduces the company's risk to crude oil price volatility. Suncor intends to settle all of the strategic crude oil hedges that were outstanding at December 31, 2004, as the related financial derivatives mature throughout 2005.

Prior to the suspension of the hedging program, the company had entered contracts to fix the price on 36,000 barrels of crude oil per day at an average price of US$23 per barrel. These contracts expire on December 31, 2005. On settlement, these contracts result in cash receipts to the company, or payments by the company, for the difference between the derivative contract and market rates for the applicable 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 in the Consolidated Statements of Earnings. In 2004, crude oil hedging decreased Suncor's net earnings by $397 million compared to a decrease of $155 million in 2003 (2002 – decrease of $160 million).

Crude oil hedge contracts outstanding at December 31, 2004, were as follows:

	Quantity (bpd)	Average Price (a)	Revenue Hedged ($ millions)	Hedge Period
Crude oil swaps	36 000	23	364(b)	2005

(a) Average price of crude oil swaps is US$/barrel WTI at Cushing.
(b) The revenue hedged is translated to Cdn$ at the year-end exchange rate for convenience purposes.

Financial Hedging Activities Suncor periodically enters into interest rate swap contracts as part of its strategy to manage 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 differentials on the exchange of periodic interest payments are recognized as an adjustment to interest expense.

The company has entered into various interest rate swap transactions at December 31, 2004. 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 transaction	Principal Swapped ($ millions)	Swap Maturity	2004 Effective Interest Rate
Swap of 6.10% Medium Term Notes to floating rates	150	2007	3.6%
Swap of 6.80% Medium Term Notes to floating rates	250	2007	4.3%
Swap of 6.70% Medium Term Notes to floating rates	200	2011	3.5%

In 2004, these interest rate swap transactions reduced pretax financing expense by $17 million compared to a pretax reduction of $12 million in 2003 (2002 – $13 million).

Fair Value of Strategic Derivative Hedging Instruments

The fair value of derivative hedging instruments is the estimated amount, based on broker quotes and internal valuation models 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)	2004	2003
Revenue hedge swaps and collars	**(305)**	(285)
Margin hedge swaps	**5**	2
Interest rate swaps	**36**	32
	(264)	(251)

The company also uses derivative instruments to hedge risks specific to individual transactions. The estimated fair value of these instruments was $9 million at December 31, 2004, compared to $1 million at December 31, 2003.

Energy Trading Activities Energy trading activities focus on the commodities the company produces. In addition to those financial derivatives used for hedging activities, the company also uses energy derivatives to gain market information and earn trading revenues. These energy trading activities are accounted for using the mark-to-market method, and as such, physical and financial energy contracts are recorded at fair value at each balance sheet date. During 2004, Suncor recorded a net pretax gain of $11 million compared to a pretax loss of $3 million in 2003 (2002 – nil) related to the settlement and revaluation of financial energy trading contracts. In 2004, the settlement of physical trading activities also resulted in a net pretax gain of $12 million compared to a pretax gain of $2 million in 2003 (2002 – $6 million). These gains were included as energy trading and marketing activities in the Consolidated Statements of Earnings. Net of related general and administrative costs, these activities resulted in 2004 net earnings of $12 million after tax compared to a net loss of $2 million after tax in 2003.

The fair value of unsettled financial energy trading assets and liabilities at December 31 were as follows:

($ millions)	2004	2003
Energy trading assets	**26**	5
Energy trading liabilities	**9**	5

The valuation of the above contracts was based on actively quoted prices and internal valuation models.

Counterparty Credit Risk The company may be exposed to certain losses in the event that counterparties to 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 net positive fair values at the reporting date. The company minimizes this risk by entering into agreements with counterparties of which substantially all are investment grade. Risk is also minimized 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)	2004	2003
Derivative contracts not accounted for as hedges	**7**	30
Unrecognized derivative contracts	**21**	27
	28	57

Environmental Regulations

Environmental laws affect 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 laws also affect refining, distribution and marketing of petroleum products and petrochemicals and require 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 that changes to environmental laws 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 usage, and reformulated fuels to support lower vehicle emissions. Changes in environmental laws 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.

Regulatory Approvals

Before proceeding with most major projects, Suncor must obtain regulatory approvals. The regulatory approval process can involve stakeholder consultation, environmental impact assessments and public hearings, among other factors. 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 impact future earnings and cash flow.

Critical Accounting Estimates

Suncor's critical accounting estimates are defined as estimates that are important to the portrayal of the company's financial position and operations, and require management to make judgments based on underlying assumptions about future events and their effects. Underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances. These 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. Critical accounting estimates are reviewed by the Audit Committee of the Board of Directors annually. The company believes the following are the most critical accounting estimates used in the preparation of its consolidated financial statements.

Property, Plant and Equipment

Suncor accounts for its Oil Sands in-situ and NG exploration and production activities using the "successful efforts" method. This policy was selected over the alternative full-cost method because Suncor believes it provides a more timely accounting of the success or failure of exploration and production activities.

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 dry hole costs are written off and reported as part of Oil Sands and NG exploration expenses in the Consolidated Statements of Earnings. Dry hole expense can fluctuate from year to year due to such factors as the level of exploratory spending, the level of risk sharing with third parties participating in the exploratory drilling and the degree of risk in drilling in particular areas.

Properties that are assumed to be productive may, over a period of time, actually deliver oil and gas in quantities different than originally estimated because of changes in reservoir performance and/or adjustments in reserves. Such changes may require a test for the potential impairment of capitalized properties 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 reduced to fair value and either completely removed from the company's records ("written off") or partially removed from the company's records ("written down") and reported as part of Oil Sands and NG DD&A expenses in the Consolidated Statements of Earnings.

The company's plant and equipment are depreciated on a straight-line basis over the estimated useful life of the assets. Firebag and NG property costs are depleted on a unit of production (UOP) basis. In each case, the expense is shown on the DD&A line in both the Consolidated Statements of Earnings and in the Schedules of Segmented Earnings. The straight-line basis reflects asset usage as a function of time rather than production levels. For example, the useful life of plant and equipment at Oil Sands base operations and Firebag operations are not based on recorded reserves as the company has access to other undeveloped properties, and bitumen feedstock from third parties, as well as the ability to provide processing services for other producers' bitumen. UOP amortization is used where that method better matches the asset utilization with production with which the asset is associated.

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. As the majority of assets are depreciated on a straight-line basis, a 10% reduction in the useful life of plant and equipment would increase annual DD&A by approximately 10%. This impact would be reflected in all business segments with the majority of the impact being in Oil Sands.

Negative revisions in NG reserves estimates will result in an increase in depletion expenses.

Overburden

As part of the process of mining oil sands, it is necessary to remove surface material such as muskeg, glacial deposits and sand. This surface material is referred to as overburden. 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 mined in the period, and as such the cash outlays can be different than the amount amortized. In 2004, the overburden amortization charge was $225 million (2003 – $208 million) compared with actual cash overburden spending of $222 million (2003 – $175 million). Oil Sands overburden amortization is reported as part of DD&A in the Consolidated Statements of Earnings. Deferred overburden costs are reported as part of "deferred charges and other" in the ConsolidatedBalance Sheets.

To ensure 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.

To allocate the deferred overburden charges, a life-of-mine approach has been adopted for each mine pit, relating the removal of all overburden (on a volume basis) to the mining of all of the oil sands ore on leases where there is regulatory approval (on a tonnage basis). By adopting this approach, an overburden "stripping ratio" is calculated that relates overburden removal costs to all proved and probable Oil Sands ore reserves. Over time, through a combination of increased mine areas, 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. In 2004, the stripping ratio increased by approximately 13% due to new operational information and mine plan changes. The effects of the increased stripping ratio were offset by lower per unit overburden removal costs. The net effect of these factors resulted in a $16 million pretax increase in the amount of overburden deferred in the year.

Asset Retirement Obligations (ARO)

Effective January 1, 2004, Suncor adopted the new Canadian accounting standard "Asset Retirement Obligations". Under this standard, the company is required to recognize a liability for the future retirement obligations associated with the company's property, plant, and equipment. An ARO is only recognized to the extent of a legal obligation associated with the retirement of a tangible long-lived asset that Suncor is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the company's total ARO amount. These individual assumptions can be subject to change based on experience.

The ARO is initially measured at fair value and discounted to present value using a credit-adjusted risk-free discount rate of 6% (2003 – 6.5%). The ARO accretes over time until the company settles the obligations and the effect is included in a separate "accretion of asset retirement obligations" expense line in the Consolidated Statements of Earnings. Payments to settle the obligations occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed 35 years. The discount rate will be adjusted, when appropriate, to reflect long-term changes in market rates and outlook.

An ARO is not recognized for assets with an indeterminate useful life because the amount cannot be reasonably estimated. An ARO for these assets will be recorded in the first period in which the lives of the assets are determinable.

In connection with company reviews of Oil Sands and NG completed in the fourth quarter of 2004, Suncor increased its estimated undiscounted total obligation to approximately $1.1 billion from the previous estimate of $1.0 billion. The increase was due to a change in the Oil Sands estimate to $940 million primarily reflecting increased estimated land reclamation costs related to the south tailings pond. The majority of the costs in Oil Sands are projected to occur over a time horizon extending to approximately 2060. In 2005, these changes in the ARO estimate are anticipated to result in additional after-tax expense of approximately $6 million.

The greatest area of judgment and uncertainty with respect to the company's asset retirement obligations 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 technology. 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 asset retirement cost estimates. The company continues to monitor and assess other possible technologies and/or modifications to the consolidated tailings process now being used.

Reserves Estimates

Suncor is a Canadian issuer and is subject to Canadian reporting requirements, including rules in connection with the reporting of its reserves. However, the company has received an exemption from Canadian securities administrators permitting it to report its reserves in accordance with U.S. disclosure requirements. Pursuant to U.S. disclosure requirements, the company discloses net proved conventional oil and gas reserves, including natural gas reserves and bitumen reserves from its Firebag in-situ leases, using constant dollar cost and pricing assumptions. As there is no recognized posted bitumen price, these assumptions are based on a posted benchmark oil price (1) adjusted for transportation, gravity and other factors that create the difference ("differential") in price between the posted benchmark price and Suncor's bitumen. Both the posted benchmark price and the differential are generally determined as of a point in time, namely, December 31("Constant Cost and Pricing"). Suncor's reserves from its

(1) Under U.S. disclosure requirements, the posted benchmark oil price utilized was Lloydminster light blend, a medium density crude oil and under Annual Average Differential Pricing, the posted benchmark oil price utilized was light sweet at Edmonton, a light density crude oil.

Firebag in-situ leases are reported as barrels of bitumen, using these Constant Cost and Pricing assumptions (see Required U.S. Oil and Gas and Mining Disclosure – Proved Conventional Oil and Gas Reserves for net proved conventional oil and gas reserves).

Pursuant to U.S. disclosure requirements, Suncor also discloses gross proved and probable mining reserves. The estimate of its mining reserves is based in part on the current mine plan and estimates of extraction recovery and upgrading yields, rather than an analysis based on constant dollar or forecast pricing and cost assumptions. In accordance with these rules, the company reports mining reserves as barrels of synthetic

crude oil based on a net coker, or synthetic crude oil yield from bitumen of 80% to 81%. Suncor does not disclose its mining reserves on a net basis as it is continuing to discuss the terms of its option to transition to the Province of Alberta's generic bitumen-based royalty regime in 2009 and accordingly the net mining reserves calculation cannot be estimated (see Required U.S. Oil and Gas and Mining Disclosure – Proved and Probable Oil Sands Mining Reserves). Suncor's Firebag in-situ leases are already subject to royalty based on bitumen, rather than synthetic crude oil. (For a full discussion of Suncor's Oil Sands Crown royalties, see page 24.)

In addition to required disclosure, Suncor's exemption issued by Canadian securities administrators permits it to provide further disclosure voluntarily. Suncor provides this voluntary disclosure to show aggregate proved and probable oil sands reserves, including both mining reserves and reserves from its Firebag in-situ leases. In its aggregate voluntary disclosure, Suncor reports reserves on the following basis:

- Gross proved and probable mining reserves, on the same basis as disclosed pursuant to U.S. disclosure requirements (reported as barrels of synthetic crude oil based on a net coker, or synthetic crude oil yield from bitumen of 80% to 81%); and

- Gross proved and probable bitumen reserves from Firebag in-situ leases, evaluated based on normalized constant dollar cost and pricing assumptions. These assumptions use a posted benchmark oil price as of December 31, but apply a differential generally intended to represent a normalized annual average for the year ("Annual Average Differential Pricing"), rather than a point in time differential, in accordance with Canadian Securities Administrators Staff Notice 51-315 (CSA Staff Notice 51-315). Bitumen reserves estimated on this basis are subsequently converted, for comparison purposes only, to barrels of synthetic crude oil based on a net coker or synthetic crude oil yield from bitumen of 82%.

Accordingly, Suncor's voluntary disclosures of proved and probable reserves from its Firebag in-situ leases will differ from the required U.S. disclosure in three ways. Reserves from Suncor's Firebag in-situ leases are:

- disclosed on a gross basis versus a net basis under U.S. disclosure requirements;

- converted from barrels of bitumen under U.S. disclosure requirements to barrels of synthetic crude oil for comparability purposes only; and

- evaluated based on 2004 Annual Average Differential Pricing, in accordance with CSA Staff Notice 51-315, versus Constant Cost and Pricing assumptions pursuant to U.S. disclosure requirements.

Under the U.S. disclosure requirements described above, Suncor announced on January 21, 2005 that it debooked proved reserves from the company's Firebag in-situ leases. December 31, 2004 point-in-time posted benchmark oil prices were unusually low and December 31, 2004 point-in-time diluent prices, which form part of the differential calculation, were unusually high. This combination resulted in a determination that Suncor's proved Firebag in-situ reserves were uneconomic as at December 31, 2004 (see Required U.S. Oil and Gas and Mining Disclosure – Proved Conventional Oil and Gas Reserves).

Under Suncor's voluntary disclosure, using 2004 Annual Average Differential Pricing, proved Firebag in-situ reserves were determined to be economic and accordingly, are disclosed under Voluntary Oil Sands Reserves Disclosure. Comparisons of these two reserve estimates will show material differences based primarily on the pricing assumptions used, but will also show differences based on whether the reserves are reported as barrels of bitumen or barrels of synthetic crude oil, and whether the reserves are reported on a gross or net basis.

All of Suncor's oil and gas reserves have been evaluated as at December 31, 2004 by independent petroleum consultants, Gilbert Laustsen Jung Associates Ltd. (GLJ). In reports dated February 9, 2005, and February 17, 2005 (GLJ Oil Sands Reports), GLJ evaluated Suncor's proved and probable reserves on its oil sands mining leases and Firebag in-situ leases respectively, pursuant to both U.S. disclosure requirements using Constant Cost and Pricing assumptions, and CSA Staff Notice 51-315, using 2004 Annual Average Differential Pricing assumptions.

Estimates in the GLJ Oil Sands Reports consider recovery from leases for which regulatory approvals have been granted. The mining reserve estimates are based on a detailed geological assessment and also consider industry practice, drill density, production capacity, extraction recoveries, upgrading yields, mine plans, operating life, and regulatory constraints.

For Firebag in-situ reserve estimates, GLJ considered similar factors such as Suncor's regulatory approval, project implementation commitments, detailed design estimates, detailed reservoir studies, demonstrated commercial success of analogous commercial projects, and drill density. Suncor's proved and probable reserves are contained within the AEUB approval area. Proved reserves are delineated with 40 to 80 acre spacing and 3D seismic control while probable reserves are delineated with 80 to 160 acre spacing and 3D seismic control. The major facility expenditures to develop proved undeveloped reserves have obtained final approval by Suncor's Board. Plans to develop the probable undeveloped reserves in subsequent phases are under way but have not yet received final approval from the Board.

In a report dated February 17, 2005 (GLJ NG Report), GLJ also evaluated Suncor's proved reserves of natural gas, natural gas liquids and crude oil (other than reserves from mining leases and the Firebag in-situ reserves) as at December 31, 2004.

More information about the evaluation of Suncor's reserves by GLJ, as well as additional oil and gas data, is available in Suncor's most recent Annual Information Form.

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

Required U.S. Oil and Gas and Mining Disclosure
Proved and Probable Oil Sands Mining Reserves

Millions of barrels of synthetic crude oil (1)	Gross Oil Sands Mining Leases (2) Proved	Probable	Proved & Probable
December 31, 2003	878	952	1 830
Revisions of previous estimates	140	(105)	35
Extensions and discoveries	—	—	—
Production	(79)	—	(79)
December 31, 2004	**939**	**847**	**1 786**

(1) Synthetic crude oil reserves are based upon a net coker, or synthetic crude oil yield from bitumen of 80% to 81%.
(2) Suncor's gross mining reserves are based in part on its current mine plan and estimates of extraction recovery and upgrading yields, rather than an analysis based on constant dollar or forecast pricing and cost assumptions.

Suncor does not disclose its mining reserves on a net, after royalty basis as it continues to discuss the terms of its option to transition to the Province of Alberta's generic bitumen based royalty regime in 2009 and accordingly the net mining reserves calculation cannot be estimated (see page 24 for a discussion of our royalty regime).

Proved Conventional Oil and Gas Reserves

The following data is provided on a net basis 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 mining activities are excluded, while Firebag in-situ reserves are included.

Net Proved Reserves (2)
Crude Oil, Natural Gas Liquids and Natural Gas

Constant Cost and Pricing as at December 31	Oil Sands business: Firebag – crude oil (millions of barrels of bitumen) (1) (3) (4)	Natural Gas business: crude oil and natural gas liquids (millions of barrels) (5)	Total (millions of barrels)	Natural Gas business: natural gas (billions of cubic feet) (5)
December 31, 2003	424	8	432	456
Revisions of previous estimates	(420)(3)	1	(419)	(23)
Purchases of minerals in place	—	—	—	14
Extensions and discoveries	—	—	—	53
Production	(4)	(1)	(5)	(54)
Sales of minerals in place	—	—	—	—
December 31, 2004	**—**	**8**	**8**	**446**

(1) Oil Sands business – Firebag net reserves means Suncor's undivided percentage interest in total reserves after deducting Crown royalties, freehold and overriding royalty interests. The calculation of these third-party interests is uncertain and based on assumptions about future prices, production levels, operating costs and capital expenditures.
(2) Although Suncor is subject to Canadian disclosure rules in connection with the reporting of its reserves, the company has received exemptive relief from Canadian securities administrators permitting it to report its proved reserves in accordance with U.S. disclosure practices.
(3) Estimates of proved reserves from Suncor's Firebag in-situ leases are based on Constant Cost and Pricing assumptions as at December 31, 2004. Due to unusually low year-end posted benchmark oil prices and unusually high year-end diluent prices, Suncor's proved reserves were determined to be uneconomic as at this year end point in time.
(4) The company has the option of selling the bitumen production from these leases and/or upgrading the bitumen to synthetic crude oil.
(5) Natural Gas business net reserves means Suncor's undivided percentage interest in total reserves after deducting interest of third parties, including Crown royalties, freehold and overriding royalties, calculated following generally accepted guidelines, on the basis of prices and the royalty structure in effect at year end and anticipated production rates. The calculation of these third-party interests is uncertain and based on assumptions about future natural gas prices, production levels, operating costs and capital expenditures. Royalties can vary depending upon selling prices, production volumes, timing of initial production and changes in legislation.

Voluntary Oil Sands Reserves Disclosure

Oil Sands Mining and Firebag
In-situ Reserves Reconciliation

The following table sets out, on a gross basis, a reconciliation of Suncor's proved and probable reserves of synthetic crude oil from its Oil Sands mining leases and bitumen, converted to synthetic crude oil for comparison purposes only, from its Firebag in-situ leases, from December 31, 2003 to December 31, 2004, based on the GLJ Oil Sands Reports, in accordance with CSA Staff Notice 51-315, using 2004 Annual Average Differential Pricing assumptions.

Estimated Gross Proved and Probable Oil Sands Reserves Reconciliation

Millions of barrels of synthetic crude oil (1)	Oil Sands Mining Leases (1)(2) Proved	Probable	Proved & Probable	Firebag In-situ Leases(1)(3) (Constant Pricing) Proved (3)	Probable (4)	Proved & Probable	Total Mining and In-situ (4) Proved & Probable
December 31, 2003	878	952	1 830	387	1 721	2 108	3 938
Revisions of previous estimates	140	(105)	35	110	179	289	324
Extensions and discoveries	—	—	—	—	—	—	—
Production	(79)	—	(79)	(3)	—	(3)	(82)
December 31, 2004	**939**	**847**	**1 786**	**494**	**1 900**	**2 394**	**4 180**

(1) Synthetic crude oil reserves are based upon a net coker, or synthetic crude oil yield from bitumen of between 80% and 81% for reserves under Oil Sands Mining Leases and of 82% for reserves under Firebag In-situ Leases. Although virtually all of Suncor's bitumen from the Oil Sands mining leases is upgraded into synthetic crude oil, the company has the option of selling the bitumen produced from its Firebag in-situ leases and/or upgrading this bitumen to synthetic crude oil and accordingly, these bitumen reserves are converted to synthetic crude oil for comparison purposes only.

(2) Suncor's gross mining reserves are evaluated in part, based on the current mine plan and estimates of extraction recovery and upgrading yields, rather than an analysis based on constant dollar or forecast pricing assumptions.

(3) Under Required U.S. Oil and Gas and Mining Disclosure, Suncor reported no proved reserves from Firebag in-situ leases. The disclosure in the table above reports proved reserves from these leases and differs in the following three ways. Reserves from Firebag in-situ leases are:
(a) disclosed in this table on a gross basis versus a net basis;
(b) converted from barrels of bitumen to barrels of synthetic crude oil in this table for comparability purposes only; and
(c) evaluated based on Annual Average Differential Pricing assumptions versus point-in-time Constant Cost and Pricing assumptions as at December 31. Accordingly, Firebag in-situ reserve estimates under Required U.S. Oil and Gas and Mining Disclosure – Proved Conventional Oil and Gas Reserves and Firebag in-situ proved reserve estimates in this table differ materially.

(4) U.S. companies do not disclose probable reserves for non-mining properties. Suncor voluntarily discloses its probable reserves for Firebag in-situ leases as it believe this information is useful to investors, and allows the company to aggregate its mining and in-situ reserves into a consolidated total for its Oil Sands business. As a result, Suncor's Firebag in-situ estimates are not comparable to those made by U.S. companies.

Employee Future Benefits

The company provides a range of benefits to its employees and retired employees, including pensions and other post-retirement health care and life insurance benefits. 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. Management continually reviews these assumptions in light of actual experience and expectations for the future. Changes in assumptions are accounted for on a prospective basis. Employee future benefit costs are reported as part of operating, selling and general expenses in the company's Consolidated Statements of Earnings and Schedules of Segmented Data. The accrued benefit liability is reported as part of "accrued liabilities and other" in the Consolidated Balance Sheets.

The assumed rate of return on plan assets considers the current level of expected returns on the fixed income portion of the plan assets portfolio, the historical level of risk premium associated with other asset classes in the portfolio and the expected future returns on each asset class. The discount rate assumption is based on the year end interest rate on high quality bonds with maturity terms equivalent to the benefit obligations. The rate of compensation increases is based on management's judgment. 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. A 1% change in the assumptions at which pension benefits and other post-retirement benefit liabilities could be effectively settled is as noted below.

($ 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
Increase (decrease) to net periodic benefit cost	(4)	4	(11)	12	6	(5)
Increase (decrease) to benefit obligation	—	—	(99)	115	30	(27)

Health care costs comprise a significant element of Suncor's post-employment benefit obligation and an area where there is increasing cost pressure due to an aging North American society. Suncor has assumed an 11.5% annual rate of increase in the per capita cost of covered health care benefits for 2004, with an assumption that this rate will decrease by 0.5% annually, to 5% by 2017, and remain at that level thereafter.

A 1% change in the assumed health care cost trend rate would have the following effect:

($ millions)	1% Increase	1% Decrease
Increase (decrease) to total of service and interest cost components of net periodic post-retirement health care benefit cost	2	(1)
Increase (decrease) to the health care component of the accumulated post-retirement benefit obligation	13	(11)

Control Environment

Based on their evaluation as of December 31, 2004, Suncor's chief executive officer and chief financial officer concluded that Suncor's disclosure controls and procedures (as defined in Rules 13(a)-15(e) and 15(d)-15(e) under the United States Securities Exchange Act of 1934 (the Exchange Act)) are effective to ensure that information required to be disclosed by Suncor in reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the United States Securities and Exchange Commission rules and forms. In addition, other than as described below, as of December 31, 2004, there were no changes in Suncor's internal controls over financial reporting that occurred during 2004 that have materially affected, or are reasonably likely to materially affect its internal controls over financial reporting. Suncor will continue to periodically evaluate its disclosure controls and procedures and internal controls over financial reporting and will make any modifications from time to time as deemed necessary.

The company is in the process of implementing an ERP system in all of its businesses to support the company's growth plan. The phased implementation is currently planned to be complete by 2006. Implementing an ERP system on a widespread basis involves significant changes in business processes and extensive organizational training. The company currently believes a phased-in approach reduces the risks associated with making these changes. Suncor believes it is taking the necessary steps to monitor and maintain appropriate internal controls during this transition period. These steps include deploying resources to mitigate internal control risks and performing additional verifications and testing to ensure data integrity.

The company has undertaken a comprehensive review of the effectiveness of its internal control over financial reporting as part of the reporting, certification and attestation requirements of Section 404 of the U.S. Sarbanes-Oxley Act of 2002. For the year ended December 31, 2004, the company's internal controls were found to be operating free of any material weaknesses. In connection with the continued implementation of its ERP system, the company expects there will be a significant redesign of its business processes during 2005, some of which relate to internal control over financial reporting and disclosure controls and procedures.

Change In Accounting Policies

Asset Retirement Obligations (ARO)

On January 1, 2004, the company retroactively adopted the new Canadian accounting standard related to "Asset Retirement Obligations". Under the new standard a liability is recognized for the future retirement obligations associated with the company's property, plant and equipment. The fair value of the ARO is recorded on a discounted basis. This amount is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the company settles the obligation.

Recently Issued Canadian Accounting Standards

Variable Interest Entities

In 2003, Canadian Accounting Guideline 15 (AcG 15), "Consolidation of Variable Interest Entities" (VIEs) was issued. Effective January 1, 2005, AcG 15 requires consolidation of a VIE where the company will absorb a majority of a VIE's losses, receive a majority of its returns, or both. The company will be required to consolidate the VIE related to the sale of equipment as described on page 23. The company does not expect a significant impact on net earnings upon consolidation of the equipment VIE. The impact on the balance sheet will be an increase to property, plant and equipment of $14 million, an increase to inventory of $8 million, and an increase to long-term debt of $22 million. The company's accounts receivable securitization program described on page 23, as currently structured, does not meet the AcG 15 criteria for consolidation by Suncor.

Liabilities and Equity

In 2003, the Canadian Accounting Standards Board approved an amendment to Handbook Section 3860 "Financial Instruments – Disclosure and Presentation" requiring certain obligations that must or could be settled with an entity's own equity instruments to be presented as liabilities. The amendment, effective for the company's 2005 fiscal year and applied on a retroactive basis will affect the company's current presentation of preferred securities as equity. The reclassification of the preferred securities from equity to long-term debt is expected to increase property, plant and equipment by $37 million, and increase 2005 DD&A by $1 million.

oil sands

Located near Fort McMurray, Alberta, Suncor's Oil Sands business forms the foundation of Suncor's growth strategy and represents the most significant portion of the company's assets. The Oil Sands business unit recovers bitumen through mining and in-situ development and upgrades it into refinery feedstock, diesel fuel and byproducts.

Oil Sands strategy focuses on:

- Acquiring long-life mineral leases with substantial bitumen resources in place.
- Sourcing low-cost bitumen supply through mining, in-situ development and third-party supply agreements, and upgrading this bitumen

supply into high value crude oil products that meet market demand.

- Increasing production capacity and improving reliability through staged expansion of Oil Sands upgrading facilities.

- Reducing costs through the application of technologies, economies of scale, direct management of growth projects, strategic alliances with key suppliers and continuous improvement of operations.

highlights

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	2004	2003	2002
Revenue	**3 596**	3 061	2 616
Production (thousands of bpd)	**226.5**	216.6	205.8
Average sales price ($/barrel)	**42.28**	37.19	33.65
Net earnings	**995**	888	782
Cash flow from operations	**1 752**	1 803	1 475
Total assets	**9 032**	7 934	7 186
Cash used in investing activities	**1 086**	1 055	630
Net cash surplus	**737**	799	729
ROCE (%) (1)	**22.9**	20.8	16.7
ROCE (%) (2)	**18.8**	17.4	15.6

(1) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for Suncor's operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non GAAP Financial Measures. See page 51.
(2) Includes capitalized costs related to major projects in progress.

Significant Developments in 2004 and Subsequent Event

- The start-up phase of stage one of Suncor's Firebag in-situ operation was completed and commercial operations commenced in the second quarter of 2004. Production in 2004 averaged 10,900 barrels per day (bpd) of bitumen, and is expected to reach its full production capacity of 35,000 bpd of bitumen in 2006.

- Cash operating costs from Oil Sands base operations averaged $11.95 per barrel during 2004 at an average natural gas price of US$6.20 per thousand cubic feet (mcf).

- Work to expand Oil Sands production capacity to 260,000 bpd by the end of 2005 continued on schedule and on budget.

- Oil Sands began construction on an estimated $3.6 billion project that, when complete in 2008, is expected to increase production capacity to 350,000 bpd.

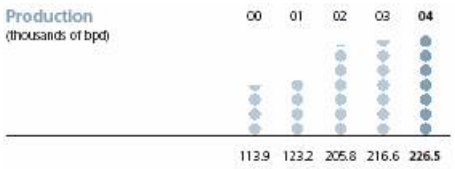
- On January 4, 2005, a fire occurred in Upgrader 2, primarily affecting a coker fractionator. As a result, base plant production capacity at Oil Sands has been temporarily reduced to about 110,000 bpd from about 225,000 bpd. Based on a preliminary assessment of the damage, Suncor estimates that production should return to full rates of approximately 225,000 bpd sometime during the third quarter, 2005.

Analysis of Net Earnings

Net earnings were $995 million in 2004 compared to $888 million in 2003. The increase was largely driven by higher benchmark commodity prices (net of the effect of widening light/heavy crude oil differentials), higher sales volumes related to higher overall production, and reductions in year-over-year non-cash income tax expenses due to changes in tax rates and resource allowance deductions. These positive factors were largely offset by increased hedging losses, higher Oil Sands Alberta Crown royalties, and the impact of a stronger Canadian dollar.

Oil Sands average production was 226,500 bpd in 2004, compared to 216,600 bpd in 2003. The increase in 2004 was largely due to new in-situ bitumen production

of 10,900 bpd. Base plant production in 2004 was lower than expected due to unplanned upgrader maintenance. In addition, 2004 in-situ bitumen production was lower than anticipated due to unscheduled water treatment system maintenance in the third quarter. Production volumes in 2003 were from base operations only, and reflect the impact of a 30-day maintenance shutdown of Upgrader 1.

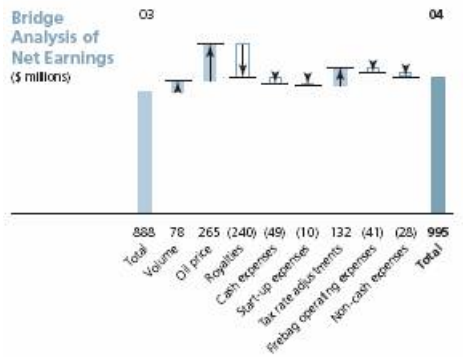


Sales volumes in 2004 averaged 226,300 bpd compared with 218,300 bpd in 2003. Higher sales volumes increased 2004 net earnings by $78

million.

Sales prices averaged $42.28 per barrel in 2004 (including the impact of pretax hedging losses of $621 million) compared with $37.19 per barrel in 2003 (including the impact of pretax hedging losses of $239 million). The average price realization was favourably impacted by the strengthening of U.S. dollar West Texas Intermediate (WTI) benchmark crude oil prices (net of widening light/heavy crude oil differentials), partially offset by the continued strengthening of the Canadian dollar from an average exchange rate of US$0.72 in 2003 to US$0.77 in 2004. Because crude oil is sold based on U.S. dollar benchmark prices, the narrowing exchange rate decreased the Canadian dollar value of crude oil products.

The net impact of the above pricing factors increased earnings by $265 million in 2004.



Cash Expenses

Cash expenses increased to $1.17 billion from $1.03 billion in 2003. Expenses were higher year-over-year due to the following factors:

- Purchases of crude oil and products increased to $75 million in 2004 from $12 million in 2003. The increase is primarily due to the repurchase of crude oil originally sold to a Variable Interest Entity (VIE) in 1999.
- The first year of in-situ operations increased cash expenses by $64 million in 2004, including natural gas purchases of $39 million.
- Upgrading costs increased by $26 million primarily due to unscheduled maintenance.

These higher expenses were partially offset by lower transportation costs and other costs of $13 million. Overall, increases in cash expenses reduced 2004 net earnings by $49 million.

Royalties

Oil Sands Alberta Crown royalties increased by $374 million to $407 million in 2004 compared to $33 million in 2003. Increased royalties reduced net earnings by approximately $240 million. For a further discussion on Crown royalties, see page 24.

Start-up Expenses

Project start-up expenses increased by $16 million ($10 million after tax) in 2004, due to commissioning and start-up expenses for in-situ operations during the first quarter of 2004.

Non-cash Expenses

Non-cash depreciation, depletion and amortization (DD&A) expense, including overburden amortization expense, increased to $503 million from $458 million in 2003. The increase was primarily due to first-time DD&A expenses from in-situ operations of $20 million, higher overburden amortization of $16 million, and higher maintenance shutdown and catalyst amortization. Higher non-cash expenses decreased net earnings by $28 million.

In 2004, Oil Sands average overburden removal stripping ratio was 0.52 cubic metres of overburden for every tonne of ore mined, compared to 0.46 cubic metres per tonne in 2003. The increased stripping ratio year-over-year was primarily due to higher proportionate levels of mining activity from the Millennium mine, which has a higher stripping ratio than the Steepbank mine, as well as updated drilling results that provided more detailed information. Overburden amortization increased to $224 million in 2004 compared with $208 million in 2003.

Stripping ratios are expected to continue to increase until 2006 as proportionately more mining activity is conducted at the company's Millennium mine. From 2006 to 2010 it is expected that all mining production will come from the Millennium mine and the stripping ratio will stabilize. (For a discussion of overburden stripping ratios see page 29.)

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 significant.

Tax Adjustments

In 2004, non-cash income tax expense was reduced by $53 million relating to reductions in the Alberta provincial tax rate. In 2003, non-cash income tax expense increased by $93 million primarily related to the impact of changes in the federal government's taxation policies for the resource sector, and an increase in Alberta and Ontario provincial tax rates. Including other minor differences, changes in effective tax rates increased net earnings by $132 million in 2004 compared to 2003.

Operating Costs

With the start of Firebag in-situ operations, Suncor reported cash operating costs from mining and upgrading production from the mine (base operations) separately from cash costs from in-situ operations. Cash operating costs for base operations increased to $949 million ($11.95 per barrel) in 2004 compared to $907 million ($11.45 per barrel) in 2003, primarily as a result of higher maintenance costs, offset by lower natural gas costs.

Natural gas purchases for base operations averaged approximately 65 million cubic feet per day (mmcf/d) in 2004, consistent with the prior year. Oil Sands natural gas costs declined to $6.74 per mcf in 2004 from $6.95 per mcf in 2003, reducing cash costs by approximately $0.15 per barrel.

Net Cash Surplus Analysis

Cash flow from operations was $1.75 billion in 2004, a slight decrease from $1.8 billion in 2003. Excluding the impact of non-cash income tax adjustments, the decrease was due to the same factors that increased net earnings, offset by higher cash overburden and reclamation spending, and higher pension funding requirements.

Net working capital decreased by $71 million in 2004 compared to a decrease of $51 million in 2003. Higher accounts receivable due to higher sales volumes and higher price realizations in the final month of 2004 compared to 2003 was more than offset by increased accounts payable and accrued liabilities related to increased capital spending in the fourth quarter and higher accrued royalties payable.

Cash flow used in investing activities increased slightly to $1.09 billion in 2004 compared to $1.06 billion in 2003. During 2004, capital spending related primarily to construction of Firebag stage two, the Millennium vacuum unit, and engineering and preliminary construction of the Millennium Coker Unit. During 2003, capital spending primarily related to construction of Firebag stage one, and engineering and preliminary construction of the Millennium Vacuum Unit, as well as spending on the planned maintenance shutdown of Upgrader 1.

Combined, the above factors resulted in a net cash surplus of $737 million in 2004, compared with a surplus of $799 million in 2003.

Subsequent Event

A fire on January 4, 2005, caused significant damage to Oil Sands Upgrader 2, reducing upgraded crude oil production capacity from base operations to about 110,000 bpd. Repair work is under way and Oil Sands expects to return to full production capacity of 225,000 bpd in the third quarter of 2005.

The timeline for recovery work is preliminary and subject to change. Further inspection of the damaged equipment will occur as the repairs progress. Any new information could modify the timetable for returning to full production.

To mitigate the impact of reduced production during the recovery period, Oil Sands plans to bring forward as many maintenance projects as possible, including all, or significant portions of, a maintenance shutdown previously planned for the fall.

Suncor's preliminary investigation into the cause of the fire suggests the issue was an isolated case.

Outlook

As a result of the January fire, specific targets for Oil Sands production, sales mix and cash operating costs are not available. Fire recovery efforts are not expected to impact expansion efforts and work to continue specific growth targets continues.

Expansion to 260,000 bpd

Work is proceeding on schedule to increase production capacity to 260,000 bpd by the end of 2005. To achieve this goal, Oil Sands must complete construction of the Millennium vacuum unit, tie in bitumen feed infrastructure and commission the new facility. The project is on budget to meet its estimated cost of $425 million.

Expansion to 350,000 bpd

The next stage of growth, expected to increase production capacity to 350,000 bpd, is also proceeding on schedule and on budget. This project is expected to reach several milestones with fabrication and transport of major vessels for the coker unit expansion scheduled to be completed during 2005.

The total cost of this project is estimated at $3.6 billion, including approximately $2.1 billion to expand Upgrader 2 and $1.5 billion to increase bitumen supply.

Incremental bitumen to feed expanded upgrading capacity is also expected to be provided under a processing agreement between Suncor and Petro-Canada, slated to take effect in 2008. Under the agreement, Oil Sands will process at least 27,000 bpd of Petro-Canada bitumen on a fee-for-service basis. Petro-Canada will retain ownership of the bitumen and resulting sour crude oil production of about 22,000 bpd. In addition, Suncor will sell an additional 26,000 bpd of Suncor proprietary sour crude oil production to Petro-Canada. Both the processing and sales components of the agreement will be for a minimum 10-year term.

Expansion to 500,000 bpd to 550,000 bpd

In planning for expansion beyond 2008, Suncor expects to file regulatory applications in 2005 to construct a third upgrader and expand its mining/extraction and in-situ operations, key steps to increasing production capacity to 500,000 to 550,000 bpd in the 2010 to 2012 time frame. Cost estimates for this project, known as Voyageur, are not yet available. Approval by regulators and Suncor's Board of Directors is required before the project can proceed.

Production Plan

Description	Regulatory Approval	Board of Directors Approval	Cost Estimate (1)	Production Capacity (bpd)	Status
Millennium vacuum unit	Yes	Yes	$425 million	260 000	Millennium vacuum unit under construction. Project is on schedule and on budget.
Coker unit expansion and expanded mining and in-situ operations	Yes	Firebag stage 2 and coker unit expansion approved. Additional Firebag stages and mining/extraction subject to approval.	$3.6 billion	350 000 in 2008	Construction under way. Project is on schedule and on budget.
Potential third upgrader – asset configuration still to be determined	No	No	Not available	500 000 to 550 000 in 2010 to 2012	Regulatory application expected to be filed in 2005.

(1) These cost estimates are based on preliminary engineering. Actual amounts will differ and the differences may be material.

Mine Extension

As part of its regulatory filing for Voyageur, Oil Sands also intends to file for approval to construct and operate an extension of the Steepbank mine. The proposed development would replace ore production that is expected to be depleted prior to the end of the decade. Currently, capital development costs are estimated at $350 million. Approval by regulators and Suncor's Board of Directors is required before construction can proceed.

To support the company's mine development plan, in January 2005, Oil Sands submitted a regulatory application to build a new primary extraction plant in closer proximity to mining operations. The cost of constructing the new extraction facility and decommissioning the existing plant has been estimated at $320 million.

Operating Licence Renewal

During 2005, Oil Sands will be required to update its 10-year operating licence by filing a renewal application with regulators. Management does not expect the operating licence renewal to affect its growth plans.

Risk/Success Factors Affecting Performance

Certain issues Suncor must manage that may affect performance include, but are not limited to, the following:

- Final amount and timing of the settlement and payment of insurance proceeds related to fire damage and interruption of business at Oil Sands.
- Additional maintenance or updated maintenance schedules related to returning Oil Sands to full production as well as delay or extension of work to tie in major vessels required to expand operations.
- Suncor's ability to finance Oil Sands growth in a volatile commodity pricing environment. Also refer to Suncor Overview, Liquidity and Capital Resources on page 21.
- The ability to complete future 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 infrastructure (housing, roads, schools, etc.), or higher prices for the products and services required to operate and maintain the operations. 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 maintaining a strong focus on engineering, procurement and project management.
- Potential changes in the demand for refinery feedstock and diesel fuel. Suncor's strategy is to reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding its customer base and offering a variety of 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.
- Suncor's relationship with its trade unions. Work disruptions have the potential to adversely affect Oil Sands operations and growth projects.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 53 under Forward-looking Statements. Also refer to Suncor Overview, Risk/Success Factors Affecting Performance on page 25.

natural gas

Suncor's Natural Gas (NG) business primarily produces conventional natural gas in Western Canada. NG's production serves as a price hedge that provides the company with a degree of protection from volatile market prices of natural gas purchased for internal consumption.

NG's strategy is focused on:

- Building competitive operating areas.
- Improving base business efficiency.
- Creating new, low-capital business opportunities.

NG's long-term goal is to achieve a sustainable return on capital employed (ROCE) of 12% at mid-cycle prices of US$4.00 to US$4.50 per thousand cubic feet (mcf). To ensure natural gas production keeps pace with company-wide natural gas purchases, NG is targeting production increases of 3% to 5% per year.

highlights

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	2004	2003	2002
Revenue	**567**	512	339
Natural gas production (mmcf/d)	**200**	187	179
Average natural gas sales price ($/mcf)	**6.70**	6.42	3.91
Net earnings	**115**	120	34
Cash flow from operations	**319**	298	164
Total assets	**965**	763	793
Cash used in investing activities	**251**	166	158
Net cash surplus	**67**	143	28
ROCE (%) (1)	**27.1**	29.2	9.5

(1) ROCE for Suncor operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non GAAP Financial Measures. See page 51.

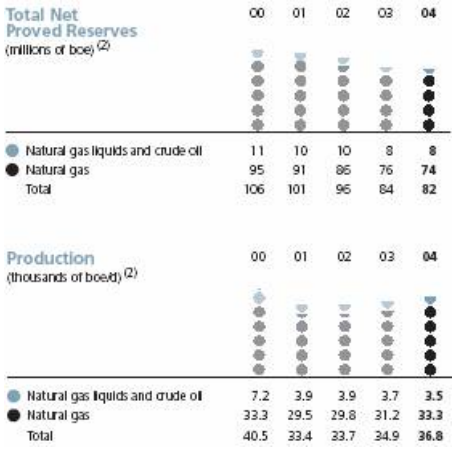
Significant Developments During 2004

- Natural gas production increased 7% to 200 million cubic feet per day (mmcf/d) in 2004 compared to purchases of approximately 120 to 130

mmcf/d. Favourable drilling results in the Foothills and Northern operating areas were a major factor in delivering volume additions.

- Higher revenues due to increased production and higher commodity prices were offset by higher royalties and higher depreciation, depletion and amortization (DD&A).

- The divestment of 62.5% of NG's interest in Suncor's Simonette gas plant yielded a $13 million after-tax gain.



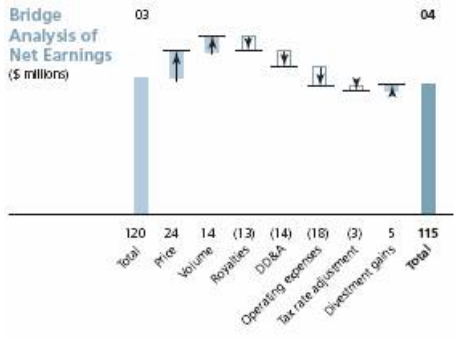
(2) For details on barrels of oil equivalent (boe), see page 14.

Analysis of Net Earnings

NG net earnings were $115 million in 2004, compared to $120 million in 2003. Higher production volumes, higher realized natural gas prices, and divestment gains were more than offset by higher DD&A, higher royalty expenses, and the costs of the final arbitrated settlement of terminated gas marketing contracts related to Enron Corporation's bankruptcy in December 2001.

NG's average natural gas production increased to 200 mmcf/d in 2004 from 187 mmcf/d in 2003. Including liquids, total 2004 production was 36,800 boe/d compared with 34,900 boe/d in 2003. Higher production volumes increased earnings by $14 million in 2004.

In 2004, NG's average realized price for natural gas was $6.70 per mcf, an increase of 4% over the average $6.42 per mcf realized in 2003. Price realizations for NG's crude oil and natural gas liquids production were also higher in 2004 due to higher benchmark crude oil prices. The combined impact of the above pricing factors increased earnings in 2004 by $24 million.



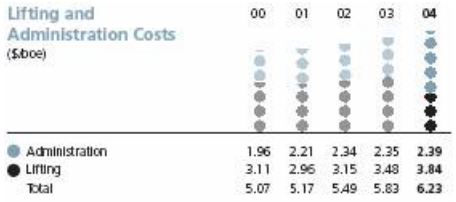
Expenses

Royalties on NG production were $124 million ($9.22 per boe) in 2004, compared to $106 million ($8.32 per boe) in 2003. The higher royalties, which reflect higher average commodity prices and increased production, reduced after-tax earnings by $13 million.

DD&A expenses increased to $115 million in 2004 from $91 million in 2003. The increase of $14 million after tax was due to a higher cost base subject to depletion, higher production, and a lower proved reserve base.

Operating costs increased to $100 million in 2004 from $73 million in 2003 due primarily to the final arbitrated settlement of terminated gas marketing contracts related to Enron Corporation's bankruptcy in December 2001. The settlement reduced earnings by $12 million after tax. Operating costs were also impacted by higher volumes and higher processing charges, which reduced earnings by $6 million after tax for a total reduction in earnings of $18 million after tax.

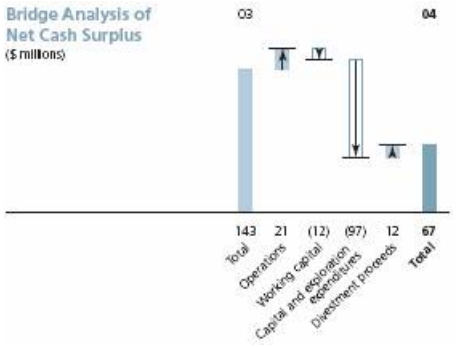
Divestment gains increased to $19 million in 2004 ($13 million after tax) from $12 million ($8 million after tax) in 2003 primarily due to the sale of a 62.5% interest in NG's Simonette gas plant for proceeds of $19 million and an after-tax gain of $13 million. NG and its partner are in the process of expanding the capacity of the plant and building a new pipeline to connect the facility with volumes produced from the Cabin Creek and Solomon fields in the Alberta Foothills. In 2003, NG divested its Mackenzie Delta non-core assets for an after-tax gain of $8 million. The higher divestment gains in 2004 as compared to 2003 increased earnings by $5 million after tax.



Net Cash Surplus Analysis

NG's net cash surplus was $67 million in 2004 compared with $143 million in 2003. Cash flow from operations increased to $319 million compared with $298 million in the prior year, largely due to increased production and higher commodity prices, partially offset by the Enron settlement and higher royalties. Changes in net working capital in 2004 resulted in a use of cash of $1 million, compared with a source of cash of $11 million in 2003, due primarily to an increase in accounts receivable.

Cash used in investing activities increased to $251 million compared with $166 million in 2003 as a result of an asset acquisition and higher capital and exploration costs, partially offset by proceeds from disposal of the Simonette gas plant. On December 29, 2004, NG acquired assets in eastern British Columbia for $33 million. These assets generate approximately 6 mmcf/d of production and consist of developed and undeveloped land.



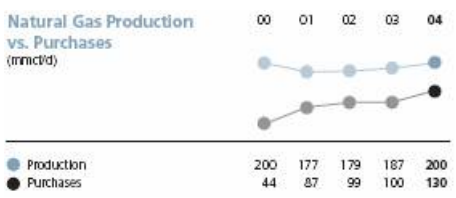
Outlook

NG's long-term financial goal is to achieve a sustainable ROCE of 12% at mid-cycle natural gas prices (US$4.00 to US$4.50/mcf). To meet this goal, management plans to continue to build competitive operating areas, grow natural gas production, improve base business efficiency and focus on strict cost control.

NG continues to work towards an operational target of increasing production by 3% to 5% per year to keep pace with the company's growing internal natural gas demands. To meet this goal, in 2005 NG is targeting average production of 205 to 210 mmcf/d and approximately 3,300 bpd of crude oil and natural gas liquids.

NG will continue to leverage its expertise and existing assets to bring reserves into production in Western Canada. However, increasing production will likely require expansion through farm-ins(1), joint-ventures or additional property acquisitions, which could expand the size and number of operating areas, or could involve new operating areas outside of Western Canada.

To support these goals, the company has budgeted $260 million in capital spending for exploration and development in 2005.



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 costs. Market demand and the availability of opportunities also influences the cost of acquisitions and the willingness of competitors to allow farm-ins on prospects.

- Risks and uncertainties associated with obtaining regulatory approval for exploration and development activities in Canada and the United States. 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 53 under Forward-looking Statements. Refer to the Suncor Overview, Risk/Success Factors Affecting Performance on page 25.

(1) 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.

energy marketing and refining – canada

Energy Marketing and Refining – Canada (EM&R) operates a 70,000 barrel per day (bpd) (approximately 11,100 cubic metres per day) capacity refinery in Sarnia, Ontario and markets refined products to industrial, wholesale and commercial customers primarily in Ontario and Quebec. Through its Sunoco-branded and joint-venture operated service networks, the business unit markets products to retail customers in Ontario. EM&R's business also encompasses third-party energy marketing and trading activities, as well as providing marketing services for the sale of crude oil and natural gas from the Oil Sands and NG operations.

EM&R's 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, including crude oil streams from Oil Sands operations.

- Increasing the profitability and efficiency of retail networks by improving average site throughput and growing non-fuel ancillary retail revenue.

- Creating downstream market opportunities to capture greater long-term value from Oil Sands production.

- Reducing costs through the application of technologies, economies of scale, direct management of growth projects, strategic alliances with key suppliers and customers and continuous improvement of operations.

As a marketing channel for Suncor's refined products, EM&R's Ontario retail networks generated approximately 58% of EM&R's total 2004 sales volumes of 97,000 bpd. EM&R's retail networks are comprised of 278 Sunoco-branded retail service stations, 23 Sunoco-branded Fleet Fuel Cardlock sites, and two 50% retail joint-venture(1) businesses that operate 147 Pioneer-branded retail service stations, 52 UPI-branded retail service stations and 14 UPI bulk distribution facilities for rural and farm fuels. Wholesale and industrial sales were responsible for approximately 37% of EM&R's refined product sales in 2004. Sun Petrochemicals Company (SPC), a 50% joint-venture between a Suncor subsidiary and a Toledo, Ohio-based refinery, generated the remaining 5% of sales.

highlights

Summary of Results

Year ended December 31 ($ millions unless otherwise noted)	2004	2003	2002
Revenue	**3 460**	2 936	2 508
Refined product sales (millions of litres)			
Sunoco retail gasoline	**1 665**	1 599	1 642
Total	**5 643**	5 477	5 286
Net earnings (loss) breakdown:			
Total earnings excluding energy, marketing and trading activities	**68**	67	23
Energy marketing and trading activities	**12**	(2)	3
Gain on sale of retail natural gas marketing business	**—**	—	35
Tax adjustments	**—**	(12)	—
Total net earnings	**80**	53	61
Cash flow from operations	**188**	164	112
Cash used in investing activities	**259**	135	34
Net cash surplus (deficiency)	**(21)**	29	63
ROCE (%)(1)	**14.6**	10.3	12.0
ROCE (%)(2)	**13.6**	10.3	12.0

(1) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for Suncor's operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non GAAP Financial Measures. See page 51.
(2) Includes capitalized costs related to major projects in progress.

Significant Developments During 2004

- EM&R started construction on the diesel desulphurization unit at the Sarnia refinery. This project will allow the company to meet federal low-sulphur diesel fuel regulations that take effect in 2006. The project, which is estimated to cost $800 million, is also expected to enable it to process approximately 40,000 bpd of Oil Sands sour crude blends.

(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 cooperative.

- Pre-development engineering, formal public consultation, preliminary project planning and regulatory approval applications were completed for a planned ethanol plant in the Sarnia region. In February 2004, Suncor received approval by Natural Resources Canada's(NRCan) Ethanol Expansion Program on its proposal for funding on the project. Subject to final approvals, NRCan would contribute $22 million towards Suncor's construction of the $120 million ethanol production facility. During the year, Suncor finalized the site location for the plant.

- EM&R completed its interior store renewal program and also started an exterior re-imaging program of all convenience stores. Same site convenience store sales increased 20% over 2003, while same site convenience store royalties increased more than 10%.

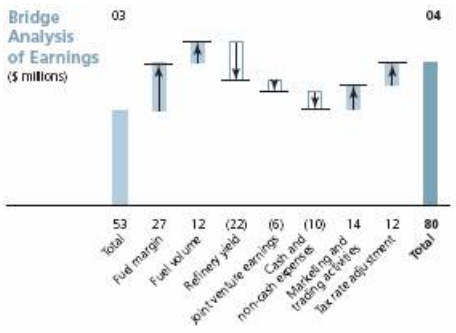
Analysis of Net Earnings

EM&R has historically reported its segmented results on a Rack Back/Rack Forward divisional basis. The Rack Back division included Ontario refining operations, as well as sales and distribution to the Sarnia refinery's largest industrial and reseller customers and the SPC joint-venture. Rack Forward included retail operations, cardlock and industrial/commercial sales, as well as the UPI and Pioneer joint-ventures.

Effective for 2004, EM&R's Rack Back and Rack Forward organizational structures were consolidated into one unit for the purposes of external segmented reporting. Prior year amounts have been reclassified to conform to the current year's presentation. EM&R's external results continue to be measured and analysed on a margin basis.

EM&R results also include the impact of Suncor's third-party energy marketing and trading activities that are discussed separately on page 46.

EM&R's net earnings increased to $80 million in 2004 from $53 million in 2003. This increase was primarily due to higher refining margins, higher sales volumes, improved refinery utilization, mark-to-market gains on inventory related derivatives, and the impact of 2003 tax adjustments. These positive impacts were partially offset by higher product purchase costs, higher cash and non-cash refinery operating expenses, and lower joint-venture earnings.



Margins

After-tax refined product margins increased by $27 million in 2004 compared to 2003, due to higher refining margins in gasoline, chemicals, diesel and jet fuel, partially offset by reduced refining margins in other products such as fuel oil and propane and decreases in retail gasoline margins. Refining margins on Suncor's proprietary refined products averaged 8.0 cents per litre (cpl) in 2004, compared to 6.5 cpl in 2003. The 23% increase was largely a result of strong refined product demand and tight North American inventory supply. Sunoco-branded retail gasoline margins averaged 4.4 cpl in 2004, compared with 6.6 cpl in 2003. The decrease was primarily due to higher crude prices and intense price competition in Ontario markets. Price competition also contributed to a decrease of $6 million in joint-venture net earnings in 2004.

Volumes

Total sales volumes averaged 97,000 bpd (15,400 cubic metres per day) in 2004, up from 94,400 bpd (15,000 cubic metres per day) in 2003, resulting in an increase in net earnings of $12 million. Higher sales of gasoline, jet and diesel fuel were partially offset by lower sales of propane and heavy fuel oils. Total gasoline sales volumes in the Sunoco-branded retail network increased to 1,665 million litres in 2004 from 1,599 million litres in 2003. Average Sunoco-branded service station site throughput was 6.2 million litres per site in 2004 compared to 5.9 million litres per site in 2003. Site throughput is an important indicator of network efficiency. EM&R's Ontario retail gasoline market share, including all Sunoco and

joint-venture operated retail sites was 19%, unchanged from 2003. Approximately 94% of EM&R's refined products were sold to the Ontario market in 2004.

Refinery Utilization

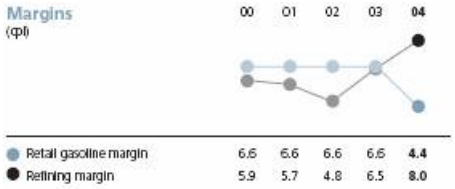
Overall refinery utilization averaged 100% in 2004, compared with 95% in 2003. The impact of scheduled and unscheduled maintenance shutdowns to portions of the refinery in the second quarter of 2004 was more than offset by above capacity utilization during the rest of the year. In 2003, utilization was below capacity primarily due to the impacts of a widespread power outage in the northeastern United States and southern Ontario during August, as well as a planned 32-day maintenance shutdown on a portion of the refinery.

Product Purchase Costs

The favourable impacts of improved refined product margins, higher volumes and higher refinery utilization were partially offset by higher third-party refined product purchase costs in 2004 compared to 2003. Refined product purchase costs increased primarily due to higher commodity prices for both purchased refined products and feedstock, partially offset by lower required purchased volumes of refined products to meet customer needs. Purchased volumes were higher in 2003 due to the power outage noted above. In total, increased purchase costs reduced 2004 net earnings by $22 million.

Cash and Non-cash Operating Expenses

Overall, cash and non-cash operating expenses increased by $10 million in 2004 compared to 2003. Cash expenses increased by $9 million in 2004, due to higher energy and freight costs, partially offset by lower salaries and benefits and lower refinery maintenance expenses. Non-cash expenses increased by $9 million in 2004, due to increased depreciation as a result of a higher asset base. These increases were partially offset by higher mark-to-market gains of $8 million on inventory-related derivatives.



Related Party Transactions

The Pioneer, UPI and SPC joint-ventures are considered to be related parties to Suncor for GAAP purposes. EM&R supplies refined petroleum products to the Pioneer and UPI joint-ventures, and petrochemical products to SPC. Suncor has a separate supply agreement with each of Pioneer, UPI and SPC. These supply agreements are evergreen, subject to termination only in accordance with the various agreements between the parties.

The following table summarizes the company's related party transactions with Pioneer, UPI and SPC, after eliminations, for the year. These transactions are in the normal course of operations and have been conducted on the same terms as would apply with unrelated parties.

($ millions)	2004	2003	2002
Operating revenues			
Sales to EM&R joint-ventures:			
Refined products	**320**	301	321
Petrochemicals	**272**	187	142

At December 31, 2004, amounts due from EM&R joint-ventures were $17 million, compared to $36 million at December 31, 2003.

Sales to, and balances with, EM&R joint-ventures are established and agreed to by the related parties and approximate fair value.

Energy Marketing and Trading Activities

Third-party energy marketing and energy trading activities consist of both third-party crude oil marketing and financial and physical derivatives trading activities. These activities resulted in net earnings of $12 million in 2004 compared to a net loss of $2 million in 2003.

Energy trading activities, by their nature, can result in volatile and large positive or negative fluctuations in earnings. A separate risk management function reviews and monitors practices and policies and provides independent verification and valuation of these activities.

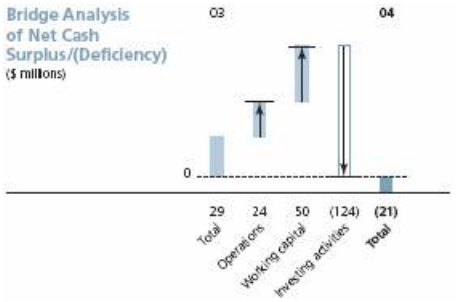
Tax Adjustments

In 2003, EM&R net earnings included a $12 million future income tax charge due to the repeal of previously announced reductions in income tax rates by the Ontario government.

Net Cash Deficiency Analysis

EM&R's net cash deficiency was $21 million in 2004 compared to a net cash surplus of $29 million in 2003. Cash flow from operations increased to $188 million in 2004 from $164 million in 2003 due to the same factors impacting net earnings. Net working capital decreased by $50 million in 2004, compared to no change in 2003. The decrease in net working capital is a result of increased accounts payable related to capital expenditures on the desulphurization project and higher purchased crude payables resulting from higher commodity prices.

The favourable impacts of the increased cash flow from operations and working capital were more than offset by an increase in cash used in investing activities, which increased to $259 million in 2004 from $135 million in 2003. The increase was primarily due to higher capital expenditures associated with the diesel desulphurization project at the Sarnia refinery, as well as increased refinery capital maintenance expenditures.



Outlook

In 2004, Suncor started construction on a diesel desulphurization project at the company's Sarnia refinery to meet current and anticipated federal sulphur regulations. Under the terms of an agreement with Shell Canada Products (Shell), the project facilities will also be used to process high-sulphur diesel from Shell's Sarnia refinery into low-sulphur diesel on a fee-for-service basis. The project will also include capital expenditures to expand the refinery's throughput capacity and enable it to process approximately 40,000 bpd of Oil Sands sour crude blends. When all components are completed in 2007, Suncor expects this project will cost a total of approximately $800 million.

Construction of a planned ethanol plant is expected to begin in 2005 and be completed by 2006, subject to regulatory approvals. This facility is expected to produce ethanol at a capacity of 200 million litres per year for blending into Sunoco-branded and Suncor joint-venture retail gasolines. The total project is expected to cost $120 million.

EM&R expects total capital spending to be approximately $400 million in 2005, with the majority directed towards meeting regulations for diesel desulphurization at the Sarnia refinery.

As a result of a fire at Oil Sands, during 2005, EM&R may be required to purchase additional synthetic crude oil feedstock to meet customer demand, resulting in higher purchased product costs.

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:

- Management expects that fluctuations in demandand supply for refined products, margin and price volatility, and market competition, including potential new market entrants, will continue to impact the business environment.

- There are certain risks associated with the execution of capital projects, including the risk of cost overruns. The diesel desulphurization project must be completed prior to June 1, 2006, to ensure compliance with legislative requirements. Numerous risks and uncertainties can affect construction schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period.

- Environment Canada is expected to finalize regulations reducing sulphur in off-road diesel fuel and light fuel oil to take effect later in the decade. Suncor believes that if the regulations are finalized as currently proposed, the new facilities for reducing sulphur in on-road diesel fuel should also allow the company to meet the requirements for reducing sulphur in off-road diesel and light fuel oil.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 53 under Forward-looking Statements. Refer to the Suncor Overview, Risk/Success Factors Affecting Performance on page 25.

refining and marketing – u.s.a.

In August 2003, Suncor acquired downstream assets based in Denver, Colorado, to create a U.S. Refining and Marketing business unit (R&M). The business operates a 60,000 barrel per day (bpd) (approximately 9,500 cubic metres per day) capacity refinery located in the Denver, Colorado area that markets refined products to customers primarily in Colorado, including retail marketing through 43 Phillips 66-branded retail

stations in the Denver area. Assets also include a 100% interest in the 480-kilometre Rocky Mountain pipeline system and a 65% interest in the 140-kilometre Centennial pipeline system.

This acquisition is part of an integration strategy aimed at improving access to the North American energy markets through acquisitions, long-term contracts and possible joint-ventures.

R&M's strategy is focused on:

- Enhancing the profitability of refining operations by improving reliability, product yields and operational flexibility to process a variety of feedstocks, including crude oil streams from Oil Sands operations.
- Increasing the profitability and efficiency of its retail network.
- Creating additional downstream market opportunities in the United States to capture greater long-term value from Oil Sands production.
- Reducing costs through the application of technologies, economies of scale, direct management of growth projects, strategic alliances with key suppliers and customers and continuous improvement of operations.

The following analysis has been prepared on the basis of a comparison of an entire year of operations in 2004 compared to five months in 2003. This has the impact of increasing measures related to earnings, margins, volumes and expenses in 2004 compared to 2003.

highlights

Summary of Results

Year ended December 31 (Cdn$ millions unless otherwise noted)	2004	2003(1)
Revenue	**1 495**	515
Refined product sales (millions of litres)		
Gasoline	**1 627**	636
Total	**3 504**	1 384
Net earnings	**34**	18
Cash flow from operations	**59**	34
Investing activities	**198**	300
Net cash surplus (deficiency)	**(71)**	(220)
ROCE (%)(2)	**12.2**	—
ROCE (%)(3)	**11.0**	—

(1) Refining and Marketing – U.S.A. reflects the results of operations since acquisition on August 1, 2003.
(2) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for Suncor's operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non GAAP Financial Measures. See page 51. For 2003, represents five months of operations since acquisition August 1, therefore no annual ROCE was calculated.
(3) Includes capitalized costs related to major projects in progress.

Significant Developments During 2004

- R&M started construction on a project to modify the Denver refinery to allow the company to meet regulations that take effect on June 1, 2006, requiring lower sulphur diesel fuel. It is also expected that modifications will enable R&M to process 10,000 bpd to 15,000 bpd of Oil Sands sour crude while also increasing the refinery's ability to process a broader slate of bitumen-based crude oil. The capital budget for this project is approximately $360 million (approximately US$300 million).
- A scheduled maintenance shutdown on certain refinery units was successfully completed in the second quarter of 2004.
- Approximately 6% of feedstock processed at the Denver refinery was supplied from Oil Sands operations, a significant step forward in Suncor's integration strategy.

Analysis of Net Earnings

R&M's external results are measured and analysed on a net margin basis.

R&M's net earnings were $34 million in 2004 compared to $18 million in 2003. In addition to the positive impact of an entire year of operations in 2004 compared to five months of operations in 2003, the increase was due to higher average refining margins and higher average sales volumes. These positive impacts were partially offset by higher product purchase costs, higher cash and non-cash refinery operating expenses, and lower refinery utilization during the first two quarters of 2004.

Margins

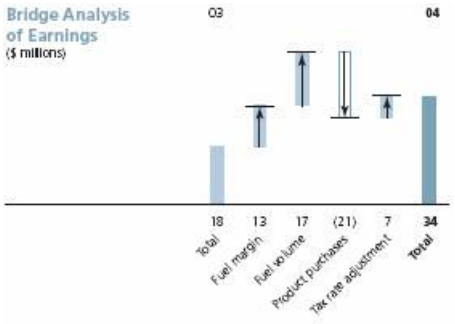
Average refining margins were 6.8 cents per litre (cpl) in 2004 compared to 5.9 cpl in 2003 reflecting significantly higher gasoline and diesel margins, partially offset by lower net realizations on asphalt and other heavy product sales. Higher refined product margins in 2004 increased earnings by $13 million. Retail margins were 5.4 cpl in 2004, compared to 5.6 cpl in 2003, reflecting weaker retail gasoline prices during the second and third quarters of 2004.

Volumes and Refinery Utilization

Sales volumes increased in 2004 due to seven more months of operations in 2004 compared to 2003. In addition, sales volumes increased by 5,800 bpd (900 cubic metres) in the last five months of 2004 as compared to the same period in 2003, primarily due to higher refinery utilization rates and decreases in refined inventory levels due to strong customer demand. Overall, the higher volumes resulted in an increase in net earnings of $17 million.

Refinery utilization in the first half of 2004 was negatively impacted by a planned 19-day maintenance shutdown on certain refinery units during the second quarter, as well as first quarter operating difficulties that were rectified during the shutdown.

Partially offsetting the positive impacts of higher margins and volumes, increased refined product purchases reduced net earnings by $21 million. The higher volume of purchased refined products was primarily due to meeting customer demand during the maintenance shutdown.



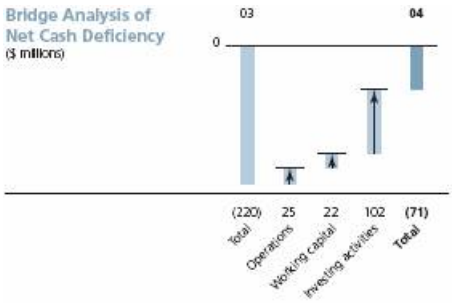
Cash and Non-cash Expenses

Increases in refinery cash expenses and non-cash depletion, depreciation and amortization were proportionately higher than 2003 due to 12 months of operations in 2004 compared to five months of operations in 2003.

Net Cash Deficiency Analysis

R&M's cash deficiency of $71 million in 2004 compared to a deficiency of $220 million in 2003. The increase in cash flow from operations to $59 million in 2004 from $34 million in 2003 was impacted by the same factors that affected net earnings. Net working capital decreased $68 million in 2004, compared to a decrease of $46 million in 2003. The decrease in 2004 was due primarily to an increase in accounts payable related to capital expenditures on the refinery modifications.

Cash used in investing activities was $198 million in 2004, compared to $300 million in 2003. Investing activities in 2004 were primarily related to costs associated with the refinery modification project. In 2003, investing activities were substantially all related to the acquisition of the Denver refinery and related assets on August 1 of that year.



Outlook

R&M estimates that it will spend approximately $260 million (approximately US$195 million) on new capital project work in 2005. Most of this investment will enable continuation of modifications that began at the Denver refinery during 2004. The project, which is expected to cost a total of approximately $360 million (approximately US$300 million), is expected to be substantially completed in early 2006.

R&M expects to spend an additional $29 million (US$24 million) by 2006 to meet existing obligations between the refinery and the United States Environmental Protection Agency and the State of Colorado. The expenditures, intended to improve environmental performance, are expected to be primarily capital.

The refinery runs a mixture of heavy and light crude oil feedstock from both Canadian and U.S. sources. In 2004, approximately 6% of R&M's crude slate came from Oil Sands. Suncor is currently assessing plans for potential additional refinery modifications post-2006 in order to have the potential to integrate up to an additional 30,000 bpd of Oil Sands crude oil. Cost estimates for this project are not yet available.

During the fourth quarter of 2005, scheduled maintenance is planned for pipeline and refinery equipment. During this estimated 42-day maintenance period, customer requirements are expected to be met from existing inventory and third-party purchases and exchanges.

During 2004, R&M was able to enter into firm sales commitments with new and existing customers to sell all of its excess refinery production. R&M also plans to improve overall profitability by seeking to optimize refining margins through a combination of branded and unbranded sales.

R&M's existing four-year contract with the local Paper, Allied-Industrial Chemical and Energy Workers International Union, which applies to hourly wage employees at the refinery, will expire in January 2006.

Risk/Success Factors Affecting Performance

Certain issues Suncor must manage that may affect performance of the R&M business include, but are not limited to, the following:

- Management expects continuing fluctuations in demand for refined products, margin and price volatility and market competitiveness, including potential new market entrants, will continue to impact the business.

- There are certain risks associated with the execution of the fuels desulphurization project, including ensuring construction and commissioning is completed in time to comply with June 1, 2006 legislative requirements. Numerous risks and uncertainties can affect construction schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period. As well, Suncor's U.S. capital projects are expected to be partially funded from Canadian operations. A weaker Canadian dollar would result in a higher funding requirement for U.S. capital programs.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 53 under Forward-looking Statements. Refer to the Suncor Overview, Risk/Success Factors Affecting Performance on page 25.

non gaap financial measures

Certain financial measures referred to in this MD&A are not prescribed by generally accepted accounting principles (GAAP). These non GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. Suncor includes cash flow from operations (dollars and per share amounts), return on capital employed (ROCE), and cash and total operating costs per barrel data because investors may use this information to analyze operating performance, leverage and liquidity. The additional information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Cash Flow from Operations per Common Share

Cash flow from operations is expressed before changes in non-cash working capital. A reconciliation of net earnings to cash flow from operations is provided in the Schedules of Segmented Data, which are an integral part of Suncor's Consolidated Financial Statements.

For the year ended December 31		2004	2003	2002
Cash flow from operations ($ millions)	A	**2 021**	2 079	1 440
Dividends paid on preferred securities ($ millions, pretax)	B	**9**	45	48
Weighted average number of common shares outstanding (millions of shares)	C	**453**	450	448
Cash flow from operations (per share)	A/C	**4.46**	4.62	3.22
Dividends paid on preferred securities (pretax, per share)	B/C	**0.02**	0.10	0.11
Cash flow from operations after deducting dividends paid on preferred securities (per share)	(A-B)/C	**4.44**	4.52	3.11

ROCE

For the year ended December 31 ($ millions, except ROCE)		2004	2003	2002
Adjusted net earnings				
Net earnings		**1 100**	1 075	749
Add: after-tax financing expenses (income)		**(10)**	(75)	72
	D	**1 090**	1 000	821
Capital employed – beginning of year				
Short-term and long-term debt, less cash and cash equivalents		**2 091**	2 671	3 143
Shareholders' equity		**4 355**	3 397	2 731
	E	**6 446**	6 068	5 874
Capital employed – end of year				
Short-term and long-term debt, less cash and cash equivalents		**2 159**	2 091	2 671
Shareholders' equity		**4 897**	4 355	3 397
	F	**7 056**	6 446	6 068
Average capital employed	(E+F)/2=G	**6 751**	6 257	5 971

Average capitalized costs related to major projects in progress (1)	H	**1 030**	817	345
ROCE (%)	D/(G-H)	**19.1**	18.4	14.6

(1) Prior to 2004, average capital employed was calculated using a simple average of opening and closing major projects in progress. In 2004, the company has used a quarterly average.

Oil Sands Operating Costs – Base Operations

		2004 (1)		2003		2002	
		$ millions	$/barrel	$ millions	$/barrel	$ millions	$/barrel
Operating, selling and general expenses		**871**		865		790	
Less: natural gas costs and inventory changes		**(142)**		(176)		(116)	
Accretion of asset retirement obligations		**21**		21		19	
Taxes other than income taxes		**28**		24		23	
Cash costs		**778**	**9.80**	734	9.25	716	9.55
Natural gas		**158**	**2.00**	169	2.15	119	1.55
Imported bitumen (net of other reported product purchases)		**13**	**0.15**	4	0.05	3	0.05
Cash operating costs – mining	A	**949**	**11.95**	907	11.45	838	11.15
Start-up costs		**26**		10		3	
Add: in-situ inventory changes		**2**		—		—	
Less: pre-start-up commissioning costs		**(4)**		(10)		(3)	
In-situ (Firebag) start-up costs	B	**24**	**0.30**	—	—	—	—
Total cash operating costs	A+B	**973**	**12.25**	907	11.45	838	11.15
Depreciation, depletion and amortization		**482**	**6.10**	458	5.80	458	6.10
Total operating costs		**1 455**	**18.35**	1 365	17.25	1 296	17.25
Production (thousands of barrels per day)		**217.0**		216.6		205.8	

Oil Sands Operating Costs – Firebag In-situ Bitumen Production

	2004 (1)	
	$ millions	$/barrel
Operating, selling and general expenses	**68**	
Less: natural gas costs and inventory changes	**(39)**	
Accretion of asset retirement obligations	**—**	
Taxes other than income taxes	**—**	
Cash costs	**29**	**8.30**
Natural gas	**39**	**11.20**
Cash operating costs	**68**	**19.50**
Depreciation, depletion and amortization	**21**	**6.00**
Total operating costs	**89**	**25.50**
Production (thousands of barrels per day)	**12.7**	

(1) Production in the base operations for the year ended December 31, 2004 includes upgraded Firebag in-situ volumes of 5,900 bpd produced in the first quarter of 2004 during the Firebag start-up period.

forward-looking statements

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, production volumes, operating and financial results and expected impact of future commitments, are Forward-looking Statements. Some of the Forward-looking Statements may be identified by words like "expects," "anticipates," "estimates," "plans," "intends," "believes," "projects," "indicates," "could," "focus," "vision," "goal," "proposed," "target," "objective" and similar expressions. These statements are not guarantees of future performance and involve a number of 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 and readers 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 the general economic,

market and business conditions; fluctuations in supply and demand for Suncor's products, commodity prices and currency exchange rates; Suncor's ability to respond to changing markets and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects (for example the Firebag in-situ development and Voyageur) and regulatory projects (for example, the clean fuels refinery modifications projects in Suncor's downstream businesses); the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering needed to reduce the margin of error or level of accuracy; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development; future environmental laws; 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 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 the January 2005 fire at the Oil Sands facility and other uncertainties resulting from potential delays or changes in plans with respect to projects or capital expenditures; actions by governmental authorities including the imposition of taxes or changes to fees and royalties; 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 the January 2005 fire, 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 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 Canadian securities commissions and the United States Securities and Exchange Commission (SEC). 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.

Appointment of Auditors

The directors and management propose that PricewaterhouseCoopers LLP be appointed as the auditors of the Corporation until the close of the next annual meeting. PricewaterhouseCoopers LLP have been auditors of Suncor for more than five years.

Fees payable to PricewaterhouseCoopers LLP in 2003 and 2004 are detailed below.

($)	2003	2004
Audit Fees	918 014	2 679 498 (1)
Audit-related Fees	135 500	23 050
Tax Fees	34 678	25 132
All Other Fees	16 070	6 150
Total	1 104 262	2 733 830

(1) Audit fees increased in 2004 due to Suncor's voluntary compliance with the reporting, certification and attestation provisions relating to internal control over financial reporting under section 404 of the United States Sarbanes-Oxley Act of 2002.

The nature of each category of fees is described below.

Audit Fees

Audit fees were paid for professional services rendered by the auditors for the audit of Suncor's annual financial statements or services provided in connection with statutory and regulatory filings or engagements.

Audit-related Fees

Audit-related fees were paid for professional services rendered by the auditors for preparation of reports on specified procedures as they relate to joint venture audits, attest services not required by statute or regulation, and membership fees levied by the Canadian Public Accountability Board.

Tax Fees

Tax fees were paid for international tax planning, advice and compliance.

All Other Fees

Fees disclosed under "All Other Fees" were paid for subscriptions to auditor provided and supported tools.

Amended and Restated Shareholder Rights Plan

Background

At the meeting, shareholders will be asked to approve and reconfirm Suncor's Shareholder Rights Plan. The Corporation's original shareholder rights plan was first implemented under an agreement dated January 25, 1996 between the Corporation and Montreal Trust Company of Canada (the "Original Plan"). The Original Plan was amended and restated, with approval of our shareholders, on April 15, 1996, April 21, 1999 and April 26, 2002. The Original Plan, as so amended and restated, is referred to as the "2002 Rights Plan". The 2002 Rights Plan is our current shareholder rights plan. Its continued existence must be approved and reconfirmed by the Independent Shareholders (as defined therein) on or before the date of the meeting.

We have reviewed our 2002 Rights Plan for conformity with current practices of Canadian companies with respect to shareholder rights plan design. We have determined that since April 2002, when the 2002 Rights Plan was last approved by shareholders, there have been few if any changes in those practices. As a result, on February 24, 2005, the Board of Directors resolved to continue the existing 2002 Rights Plan with minimal amendments, by approving an amended and restated shareholder rights plan (the "2005 Rights Plan" or the "2005 Plan") proposed to be dated April 28, 2005, subject to approval by the Independent Shareholders at the meeting. Other than the few exceptions described in Appendix C to this circular, the 2005 Rights Plan is identical to the 2002 Rights Plan in all material respects.

A summary of the key features of the 2005 Plan is attached as Appendix C to this circular. All capitalized terms used in this section of the circular and in Appendix C have the meanings set forth in the 2005 Rights Plan, unless otherwise indicated. The complete text of the 2005 Rights Plan is available to any shareholder on request from us at 112 – 4th Avenue S.W., Calgary, Alberta, T2P 2V5, by calling 1-800-558-9071, by e-mail request to info@suncor.com, or by clicking on "Shareholder Rights Plan" in the Investor Relations menu on our web site at www.suncor.com.

Statement of Corporate Governance Practices

Suncor's Board of Directors is committed to maintaining high standards of corporate governance, and regularly reviews them in light of changing practices, expectations and legal requirements. Information on Suncor's corporate governance practices is set out in Appendix B to this Circular, which summarizes the corporate governance guidelines (the "TSX Guidelines") of the Toronto Stock Exchange, and Suncor's alignment with them. Appendix B should be read in conjunction with the following general description of Suncor's current system of corporate governance.

The cornerstone of Suncor's governance system rests with its Board of Directors, whose fundamental duty is to supervise the management of Suncor's business and affairs. The Board has written terms of reference (see page 35 regarding the "charter" of the Board of Directors), that include a mandate outlining its major goals and duties. The Board of Directors has adopted a management control process policy that delegates to management the responsibility and authority to direct Suncor's day-to-day operations, subject to compliance with Board-approved budgets and strategic plans. Under the policy, certain matters, including the acquisition of new lines of business and significant acquisitions, divestments and long-term financing, among other things, must be approved in advance by the Board of Directors.

The Board's terms of reference outline the Board's major goals and duties. These range from specific matters, such as the declaration of dividends, that by law must be exercised by the Board, to its general role to determine, in broad terms, the purposes, goals, activities and general characteristics of Suncor. It reviews with management the Corporation's objectives and goals, and the strategies management proposes in order to achieve those goals and objectives. It also monitors the Corporation's progress in these areas. It provides both leadership and policy direction to management, to ensure high standards of legal and ethical conduct are developed and maintained, and to incorporate sustainability concepts into its strategic visions and implementation plans. The Board ensures the continuity of executive management by assuming responsibility for the appointment of a chief executive officer and overseeing succession planning for that key role. It also monitors and evaluates the performance of the CEO and other senior officers against established objectives and criteria that support the Corporation's strategic plans. The Board plays a key role in the oversight of the Corporation's financial matters, including capital structure management, financial results reporting, and oversight of risk management, monitoring and mitigation systems and procedures.

The Board of Directors discharges its responsibilities through preparation for and attendance at regularly scheduled meetings, and through its four standing committees, each of which has a written mandate (charter). Subject to limited exceptions, these committees generally do not have decision-making authority; rather, they convey their findings and recommendations on matters falling within their respective mandates to the full Board of Directors. The committees also have the authority to conduct any independent investigations into matters which fall within the scope of their responsibilities, and may engage external advisors (as may the full Board or an individual director), at Suncor's expense, to assist them in fulfilling their mandate.

In accordance with its terms of reference, the Board is currently comprised of a majority (eleven of thirteen members) of independent (unrelated) directors. Four of five members of the Environment, Health and Safety Committee are independent directors. The Audit Committee, the Human Resources and Compensation Committee ("HR&CC") and the Board Policy, Strategy Review and Governance ("Board Policy") Committee are comprised entirely of independent (unrelated) directors. Members of the Audit Committee are required to be financially literate, in accordance with criteria established by the Board reflecting stock exchange and legal requirements. In addition, at least one member of the Audit Committee must be determined by the Board to be an "audit committee financial expert". The Board has determined Mr. Ferguson, the Chair of the Audit Committee, and an independent (unrelated) director, to be such an expert (See Appendix B for a description of the Board's independence criteria and determinations).

The following is a brief summary of the key functions, roles and responsibilities of Suncor's Board committees.

Policy, Strategy Review and Governance Committee

The Board Policy Committee assists the Board in two areas: corporate governance and corporate strategy. In its governance role, the committee is mandated to determine Suncor's overall approach to governance issues and key corporate governance principles. The Board Policy Committee also reviews key matters pertaining to Suncor's values, beliefs and standards of ethical conduct.

The committee annually assesses and evaluates the overall performance and effectiveness of the Board of Directors, its committees, and individual directors, both as directors and as chairs of the Board or a particular Board committee. Each year, directors complete a confidential questionnaire that includes both a self-assessment and peer review to assess individual performance. The resulting data is analyzed and presented to the Board Policy Committee, who then report to the full Board of Directors, with any recommendations for enhancing or strengthening effectiveness. The Chairman of the Board reviews data relating to individual performance and conducts one-on-one meetings with each director focused on individual effectiveness.

In its strategy role, the committee reviews and provides advice with respect to the preliminary stages of key strategic initiatives and projects, and reviews and assesses processes relating to long range and strategic planning and budgeting.

Audit Committee

The Audit Committee assists the Board in matters relating to Suncor's internal controls, internal and external auditors and the external audit process, oil and natural gas reserves reporting, financial reporting and public communication, and certain other key financial matters. The committee is also mandated to provide an open avenue of communication between management, the internal and external auditors, and the Board of Directors.

In fulfilling its role, the Audit Committee monitors the effectiveness and integrity of the Corporation's financial reporting, management information and internal control systems. The Audit Committee exercises general oversight over the internal audit function, by reviewing the plans, activities, organizational structure, qualifications and performance of the internal auditors. The appointment or termination of Suncor's chief officer in charge of internal audit is reviewed and approved by the Audit Committee. This officer has a direct reporting relationship with the committee and meets with them, in the absence of other members of management, at least quarterly. The committee also monitors compliance with Suncor's business conduct code, by conducting an annual review of the code and the related annual compliance program, and monitoring the status and resolution of any complaints relating to code violations. The business conduct code applies to all employees and officers, including its chief executive officer and chief financial officer.

The Audit Committee plays a key role in relation to Suncor's external auditors. It initiates and approves their engagement or termination, subject to shareholder approval, and monitors and reviews their independence, effectiveness, performance and quality control processes and procedures. The Audit Committee reviews, with management and external auditors, significant financial reporting issues, the conduct and results of the annual audit, and significant finance, accounting and disclosure policies and other financial matters. The Audit Committee also plays a key role in financial reporting, by reviewing Suncor's core disclosure documents, being its annual and interim financial statements, Management's Discussion and Analysis (MD&A) and annual information form (Form 40-F in the United States). The committee approves interim financial statements and interim MD&A and makes recommendations to the Board with respect to approval of the annual disclosure documents.

The Audit Committee also plays a key oversight role in the evaluation and reporting of Suncor's oil and natural gas reserves. This role includes review of Suncor's procedures relating to reporting and disclosure, as well as those for providing information to Suncor's independent reserves evaluators (the "Evaluator"). The committee annually approves the appointment and terms of engagement of the Evaluator, including their qualifications and independence, and any changes in their appointment. Suncor's annual reserves data and report of the Evaluator is annually reviewed by the committee prior to approval by the full Board of Directors.

The committee reviews the key policies and practices of the Corporation with respect to cash management, financial derivatives, financing, credit, insurance, taxation, commodities trading and related matters. It also reviews the assets, financial performance, funding and investment strategy of the Corporation's registered pension plan, as well as the terms of engagement of the plan's actuary and fund manager, and any significant actuarial reports. The Audit Committee oversees generally the Board's risk management governance model by conducting periodic reviews to ensure the principal risks of Suncor's business are reflected in the mandates of the Board and its committees.

Appendix A

Board of Directors Meetings Held and Attendance of Directors

The information presented below reflects Board of Directors and Committee meetings held and attendance of directors for the year ended December 31, 2004.

	Number of Meetings
Board of Directors	6
Environment, Health and Safety Committee	4
Human Resources and Compensation Committee	6
Audit Committee	9
Board Policy, Strategy Review and Governance Committee	5

Summary of Attendance of Directors

Director	Board Meetings Attended	Committee Meetings Attended
Mel Benson	6 of 6	10 of 10
Brian A. Canfield	6 of 6	11 of 11
Susan E. Crocker	6 of 6	11 of 11
Bryan P. Davies	6 of 6	13 of 13
Brian Felesky	6 of 6	13 of 13
John T. Ferguson	6 of 6	14 of 14
W. Douglas Ford	3 of 3(2)	9 of 10
Richard L. George	6 of 6	N/A(1)
John R. Huff	6 of 6	11 of 11
Robert W. Korthals	6 of 6	9 of 9
M. Ann McCaig	6 of 6	10 of 10
Michael O'Brien	6 of 6	4 of 4
JR Shaw	6 of 6	11 of 11

(1) As a member of management, Mr. George does not serve on any of the standing committees of the Board.
(2) Mr. Ford became a member of the Board of Directors at the April 29th, 2004 annual and special meeting of the shareholders of the Corporation.

The following summarizes the current membership of each committee:

Committee	Committee Members As of February 28, 2005	
Audit Committee (all members independent)	John T. Ferguson (Chair) Bryan P. Davies Brian A. Felesky	W. Douglas Ford Robert W. Korthals
Board Policy, Strategy Review and Governance Committee (all members independent)	John R. Huff (Chair) Brian A. Canfield Susan E. Crocker	John T. Ferguson JR Shaw

Environment, Health and Safety Committee (all members independent except Mr. O'Brien)	M. Ann McCaig (Chair) Mel E. Benson Bryan P. Davies	Brian A. Felesky W. Douglas Ford Michael W. O'Brien
Human Resources and Compensation Committee (all members independent)	Brian A. Canfield (Chair) Mel E. Benson Susan E. Crocker	John R. Huff M. Ann McCaig JR Shaw

Corporate Governance Guideline	Suncor Alignment	Commentary
d. Communications policy	**Yes**	The Board of Directors is specifically mandated to ensure systems are in place for communications with Suncor's shareholders and other stakeholders. Through Corporation policies, procedures and processes, Suncor seeks to interpret its operations for its shareholders and other stakeholders, through a variety of channels, including its periodic financial reports, securities filings, news releases, environmental reports, webcasts, an external web site, briefing sessions and group meetings. The Corporation encourages and seeks stakeholder feedback through corporate communications and investor relations programs. The Board, either directly or through the activities of the Audit Committee, reviews and approves all quarterly and annual financial statements and related management's discussion and analysis, management proxy circulars and annual information forms, among others. The Corporation has a communication policy that addresses the Corporation's interaction with shareholders, investment analysts, other stakeholders and the public. The policy includes measures to avoid selective disclosure of material information. Suncor's business conduct code addresses the Corporation's obligations for continuous and timely disclosure of material information. These policies are reviewed at least annually by the Corporation. The Audit Committee reviews and approves the Corporation's communication policy and oversees an annual review of compliance with the Corporation's standard of business conduct code.
e. Integrity of internal control and management information systems	**Yes**	The Board of Directors is specifically mandated to ensure processes are in place to monitor and maintain the integrity of Suncor's internal control and management information systems. The Audit Committee is specifically mandated to assist the Board of Directors by reviewing the effectiveness of financial reporting, management information and internal control systems. This includes a review of the evaluation of these systems by internal and external auditors, as well as the activities, organizational structure and qualifications of internal auditors, and the independence and effectiveness of external auditors.
2. Majority of directors should be "unrelated" (independent)	**Yes**	The Board reviews the independence of its members annually and has determined based on its most recent annual review conducted in February 2005 that all but two (Richard L. George, Suncor's President and CEO, and Michael W. O'Brien, who retired as Suncor's CFO and Vice President, Corporate Development in 2002) of its thirteen directors are unrelated and independent. Subject to Mr. O'Brien's re-election, pursuant to independence criteria approved by the Board, he will be reclassified an unrelated and independent director as of July 2005, being expiry of the three year cooling-off period applicable to former executives.

Corporate Governance Guideline	Suncor Alignment	Commentary
b. All members should be non-management directors.	**Yes**	All members are outside, unrelated (independent) directors. The Board has affirmatively determined that all members of the Audit Committee are financially literate and has designated Mr. Ferguson, an independent (unrelated) director, as "Audit Committee Financial Expert" pursuant to the following criteria:

			The Board has defined financial literacy generally as the ability to read and understand financial statements, and has defined an Audit Committee Financial Expert as a director who has an understanding of generally accepted accounting principles and financial statements; the ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves; experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and complexity of accounting issues that are generally comparable to Suncor's, or experience actively supervising one or more persons engaged in such activities; an understanding of internal control over financial reporting; and an understanding of audit committee functions. The Board has also established criteria to assist the Board in evaluating each director's education and experience against the financial literacy and expertise requirements. Pursuant to the Board Terms of Reference, Audit Committee members must not be members of the audit committees of more than two other public companies, unless the Board determines that simultaneous service on a greater number of audit committees would not impair the member's ability to effectively serve on Suncor's Audit Committee. Mr. Korthals is currently on the audit committee of five public companies in addition to Suncor. The Board has determined that this fact does not impair Mr. Korthals' ability to effectively serve on Suncor's Audit Committee based on an analysis of Mr. Korthals time commitments in general, the demands of those other committees, and the time commitment required of members of Suncor's Audit Committee.
14.	Implement a system to enable individual directors to engage outside advisors at the Corporation's expense.	**Yes**	The Board of Directors, its committees, and individual directors may engage outside advisors at Suncor's expense with the approval of the Chairman of the Board of Directors, Chairman of the Board Policy Committee or Chairman of the applicable committee.

Exhibit 99.4



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 inclusion 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), Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234) and Form S-8 (File No. 333-118648), of Suncor Energy Inc. of our report dated February 23, 2005 relating to the financial statements, management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting, which appears in the Annual Report to Shareholders.

"PRICEWATERHOUSECOOPERS LLP"

Chartered Accountants
Calgary, Alberta
March 30, 2005

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 99.5

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 of the Provinces of Canada

Dear Sirs

Re: Suncor Energy Inc.

We refer to the following reports dated February 17, 2005, February 9, 2005 and February 17, 2005 (collectively the "Reports"), prepared by Gilbert Laustsen Jung Associates Ltd.:

- the Reserves Assessment and Evaluation of Canadian Oil and Gas Properties of Suncor Energy Inc. Natural Gas effective December 31, 2004;
- the letter report, as to the synthetic crude oil reserves effective December 31, 2004 associated with the Suncor Energy Inc. oil sands operations located near Fort McMurray, Alberta; and
- the Reserves Assessment and Evaluation of Firebag effective December 31, 2004.

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 2004 fiscal year (AIF) and its annual report on Form 40-F (Form 40-F), and the registration statements of Suncor Energy Inc. on Form F-3 (File No. 333-7450), Form F-10 (File No. 333-14242), Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234) and Form S-8 (File No. 333-118648).

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.

"GILBERT LAUSTSEN JUNG ASSOCIATES LTD."

Dana B. Laustsen, P. Eng.
Executive Vice-President

Dated: March 30, 2005
Calgary, Alberta
CANADA

EXHIBIT 99.6

Certificate of President and Chief Executive Officer Pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a)

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

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

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 Issuer as of, and for, the periods presented in this annual report;

4. The Issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Issuer, 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the Issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the Issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

---

5. The Issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Issuer's auditors and the audit committee of Issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Issuer's internal control over financial reporting.

DATE: March 30, 2005

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

EXHIBIT 99.7

Certificate of Senior Vice President and Chief Financial Officer Pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a)

I, J. KENNETH ALLEY, Senior Vice President and Chief Financial Officer of Suncor Energy Inc. ("Issuer"), certify that:

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

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 Issuer as of, and for, the periods presented in this annual report;

4. The Issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Issuer, 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the Issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the Issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

---

5. The Issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Issuer's auditors and the audit committee of Issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Issuer's internal control over financial reporting.

DATE: March 30, 2005

"J. KENNETH ALLEY"
J. KENNETH ALLEY
Senior Vice President and
Chief Financial Officer

EXHIBIT 99.8

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

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, RICHARD L. GEORGE, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of the operations of the Company.

"RICHARD L. GEORGE"
RICHARD L. GEORGE
President and Chief Executive Officer
Suncor Energy Inc.

DATE: March 30, 2005

EXHIBIT 99.9

Certificate of the Senior Vice President 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 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

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, J. KENNETH ALLEY, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of the operations of the Company.

"J. KENNETH ALLEY"
J. KENNETH ALLEY
Senior Vice President and Chief Financial Officer
Suncor Energy Inc.

DATE: March 30, 2005