# 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, 2005**
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, 2005 there were 457,664,506 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

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**ANNUAL INFORMATION FORM**



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**SUNCOR ENERGY INC. ANNUAL INFORMATION FORM**

**March 1, 2006**

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**ANNUAL INFORMATION FORM**

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## GLOSSARY OF TERMS

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

**Barrel of Oil Equivalent (BOE)**

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

**Bitumen/Heavy Crude 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 crude 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.

**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.

**Development Costs**

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

**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.

**Feedstock**

Purchases of components required in the production of refined product other than crude oil.

**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.

**Gross Production/Reserves**

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. This product traditionally sells at less than the cost of crude oil.

**In-situ Oil**

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

**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.

**MD&A**

Suncor’s Management’s Discussion and Analysis dated March 1, 2006, accompanying its audited consolidated financial statements, notes thereto and auditor’s report thereon, as at and for the three years in the period ended December 31, 2005, 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.

**Oil Sands**

Oil sands are a naturally occurring mixture of water, sand, clay and bitumen, a very heavy crude oil.

**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.

**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 U.S. 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

(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 reserves in accordance with U.S. disclosure practices. 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 20 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 Petroleum Consultants Ltd. ("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.



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 anticipated date of resumption of production must be known.

**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 oil sands/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 as well as production using conventional methods.

**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 a territory without existing proved reserves, with the intention to discover commercial reservoirs or deposits of crude oil and/or natural gas.

**CONVERSION TABLE**

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

Notes:

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

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

**CURRENCY**

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

**FORWARD-LOOKING STATEMENTS**

This Annual Information Form contains certain forward-looking statements that are based on 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; labour and material shortages; and other facilities 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 fires, 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 Suncor 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. Information contained in or otherwise accessible through our website does not form a part of this AIF. All such references are inactive textual references only.

References herein to our 2005 Consolidated Financial Statements mean Suncor's audited consolidated financial statements prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), notes thereto and auditor's report thereon, as at and for the three years in the period ended December 31, 2005.

## NON GAAP FINANCIAL MEASURES

Certain financial measures referred to in this AIF that are not prescribed by GAAP, namely, cash flow from operations 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.

### 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 in Canada under the Sunoco brand 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, bitumen and byproducts such as petroleum coke, sulphur and gypsum, produced by Suncor's Oil Sands business, through this indirect Suncor subsidiary. Through this subsidiary we also administer Suncor's energy trading activities, market certain third party products, and procure crude oil feedstocks for Suncor's downstream businesses and natural gas for our Oil Sands and Energy Marketing and Refining business. 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 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 the Suncor Energy Oil Sands Limited Partnership. The partnership held certain net profits interests related to our oil sands business and natural gas business and effective January 1, 2006, Suncor Energy Inc. contributed, subject to certain exceptions, its oil sands assets to the partnership. This internal reorganization has no effect on operations or on our consolidated net earnings.

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 are strategically focused on developing one of the world's largest petroleum resource basins – Canada's Athabasca oil sands. In addition, 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 businesses:

Our Oil Sands business, 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, 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 natural 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 indirectly wholly-owned U.S. subsidiary, Suncor Energy (Natural Gas) America Inc., acquires land and explores for coal bed methane in the United States.

Our third business, 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.

Our fourth business, 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.

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 2005, we produced approximately 206,100 BOE per day, comprised of 174,500 barrels per day (bpd) of crude oil and natural gas liquids and 190 million cubic feet per day (mmcf/d) of natural gas. In 2004, the most recent period with published results, we were the second largest crude oil and natural gas liquids producer in Canada (approximately 9%(3) of Canada's crude oil production in 2004) and the 18th largest natural gas producer in Canada.(4)

In 2005, we sold approximately 96,000 bpd (2004 – 97,000 bpd) or 15,200 $m^3$ per day (2004 – 15,400 $m^3$ per day) of refined products, mainly in Ontario but also in the United States and Europe through our Energy, Marketing & Refining business. Our refined product sales in Ontario represented approximately 19% (2004 – 19%) of Ontario's total refined product sales in 2005. In 2005, our Refining & Marketing business sold approximately 86,200 bpd or 13,700 $m^3$ of refined products in Colorado, including approximately 69,200 bpd or 11,000 $m^3$ per day of light oils (gasoline and distillates) (2004 - 58,500 bpd

(3) CAPP Crude Oil Report – Table 9 Canadian Crude Oil Production and Supply

(4) Oilweek – July 2005, Top 100 Oil and Gas Producers



or 9,300 $m^3$ per day, including approximately 45,300 bpd or 7,200 $m^3$ per day of light oils).

**Three-Year History**

***Oil Sands (OS)***

*OS growth* – Since the completion of our Millennium project in 2001, which nearly doubled the production capacity of our operation to 225,000 bpd, our multi-phased growth strategy is to further increase production capacity to 500,000 to 550,000 bpd in 2010 to 2012. Key components of this strategy include:

- Increasing bitumen supply through the development of the Firebag in-situ oil sands reserves. The first phase of Firebag began producing bitumen in 2004 and the second phase of Firebag is expected to commence commercial operations during the first quarter of 2006. The Firebag Stage 2 project cost $540 million.

- Increasing production capacity to 260,000 bpd through the construction and commissioning of a new vacuum unit. Construction of the project began in 2002 with commissioning successfully completed in the fourth quarter of 2005. This project cost $450 million and was completed on time and on budget. In addition, we also completed a debottleneck of our Steepbank mine operation.

- Increasing production capacity to 350,000 bpd in 2008, including approximately $2.1 billion for an additional coker unit to expand Upgrader 2. We currently estimate an additional $1.5 billion in costs 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. It is currently estimated that constructing the upgrader will cost approximately $5.9 billion. The estimated capital cost is provided at a very preliminary stage and is subject to a high level of uncertainty. The project scope and engineering detail will continue to evolve and will influence the estimated capital cost. Integration opportunities in the downstream, market analysis, advances in new technology, availability of labour and the cost of critical components such as steel and fabrication, among other factors, will also affect project scope and cost estimates. In respect to the increased bitumen feed portion of the project, estimated costs, and commencement date continue to be finalized. Approval of regulators and our Board of Directors is also required before the project can proceed.

Cost estimates for major projects involve uncertainties and evolve in stages. For a discussion of this process, an update on the status of our significant capital projects in progress and an explanation of “on time and on budget”, see page 26 of our MD&A, incorporated by reference herein. The $2.1 billion estimated cost for the coker unit has a range of uncertainty of +/- 10%. The $1.5 billion estimated cost for increased bitumen supply has a range of uncertainty of +30% / -20%. The $5.9 billion estimated cost for a third upgrader has a range of uncertainty of +50% / -30%.

*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 our 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. In addition to regulatory



approvals, both of these projects also require the approval of our Board of Directors before they can proceed.

*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 we 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 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(5) 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, we do not currently anticipate that the cost implications of federal and provincial climate change plans will have a material impact on our 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. Future federal legislation, together with provincial emission reduction requirements such as those required under the Climate Change and Emissions Management Act (Alberta)

may require further reduction of emissions intensity from our operations. 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.

*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 122,000 bpd for the first nine months of the year. To mitigate the impact of reduced production during the recovery period, certain maintenance projects, including a maintenance shutdown previously planned for fall 2005, were moved forward. Repair work and maintenance was completed in September 2005. Our findings into the cause of the fire indicate that it was likely a result of corrosion to a recycle line, causing it to rupture. Assessments indicate the issue related to the fire was an isolated case. We expect that our property loss and business interruption insurance policies will substantially mitigate the financial impact of the fire. For additional information on our insurance policies and recoveries to date refer to note 10(b) to our 2005 consolidated financial statements, and page 24 of our MD&A.

*Bitumen Royalty Option Agreement* – In September 2005, an agreement was reached with the Alberta Government on the terms and conditions of Suncor's option to transition to the generic bitumen-based royalty regime in 2009. Should Suncor elect to transfer to the bitumen based royalty, we would pay a royalty based on 25% of bitumen revenues, minus allowable costs. We have until late 2008 to decide if we will exercise the option and move to the generic bitumen based royalty.

***Natural Gas (NG)***

*South Rosevear Gas Plant* – In January 2006, subsequent to year-end, we disposed of 15% of the total interest in the South Rosevear gas plant for proceeds of $12 million. We currently retain a 60.4% interest and continue to operate the gas plant.

*Divestment of non-core properties* – in 2005, we disposed of non-core properties for proceeds of $21 million.

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



*Simonette Gas Plant* – In December 2005, we, along with our partner, completed a plant capacity expansion and a new pipeline to connect the Simonette plant with volumes produced from the Cabin Creek and Solomon fields in the Alberta Foothills. In November 2004, Natural Gas divested 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.

*Land Acquisition* - In December 2004, we acquired assets in eastern British Columbia for $33 million. These assets generated approximately 6 mmcf/d of production in 2005, and consist of developed and undeveloped land.

*Settlement* - Also in December 2004, we 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.

*Frontier Disposition* - During 2003, we 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.

***Energy Marketing & Refining - Canada (EM&R)***

*Desulphurization Projects* – Canadian federal legislation passed in 1999 mandated average sulphur levels in gasoline at 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 bpd 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. The project is currently on time and on budget.

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 modify the refinery's processing 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.

Cost estimates for major projects involve uncertainties and evolve in stages. For a discussion of this process, an update on the status of our significant capital projects in progress and an explanation of "on time and on budget", see page 26 of our MD&A, incorporated by reference herein.

*Ethanol 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. In 2005 final environmental approval was received from Natural Resources Canada and the Ontario Ministry of the Environment. Construction of the facility began in 2005 and is expected to be completed in 2006 at



an estimated cost of $120 million. Natural Resources Canada has contributed $19 million towards this project to date through their Ethanol Expansion Program. An additional $3 million contribution is due once the plant is operational.

***Refining & Marketing – U.S.A. (R & M)***

On August 1, 2003, we acquired a Denver area 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. During 2005 this refinery processed approximately 4,600 bpd of oil sands crude oil, including 2,150 bpd of oil sands crude oil from our Oil Sands operations at this refinery. We paid US$150 million (approximately Cdn$210 million) for the assets, plus approximately US$44 million (approximately 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 164 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, significantly completed during 2005 and expected to be fully completed during 2006, will total approximately Cdn$39 (approximately US$33 million). These expenditures, intended to reduce air emissions at the refinery, are primarily capital in nature.

On May 31, 2005 we acquired a second refinery from Valero Energy Corporation ("Valero") in the Denver area adjacent to the refinery we acquired in 2003. The 30,000 bpd Valero refinery was purchased for Cdn$37 million (US$30 million) plus working capital and associated oil and product inventory adjustments, for a total acquisition cost of Cdn$62 million (US$50 million ). The refinery was acquired by purchasing all of the issued and outstanding stock of Valero's indirect wholly-owned subsidiary, Colorado Refining Company ("CRC"). CRC was subsequently merged into Suncor Energy (USA) Inc. effective August 1, 2005. Our intention is to fully integrate the two operations, providing an expected combined refining capacity of approximately 90,000 bpd in the U.S..

Along with the purchase of the Valero assets, Suncor assumed environmental regulatory and contractual obligations of CRC at the refinery, including CRC's obligation under a Consent Decree with the United States Environmental Protection Agency, the United States Department of Justice and the State of Colorado for alleged violations of air regulations prior to our purchase, as well as a Compliance Order on Consent with the State of Colorado, relating to groundwater and soil contamination. The Consent Decree obligations are expected to require expenditures of approximately Cdn$25 million (US$20 million) through 2011.

*Desulphurization Projects* - R&M estimates it will spend approximately Cdn$465 million (US$390 million) to meet requirements for 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 clean fuels legislation requires production of lower diesel sulphur levels (15 ppm) by June 2006 and lower gasoline sulphur levels (30 ppm average, 80 ppm cap) by 2009. Permit approval and construction of the diesel desulphurization facilities commenced in 2004 and is planned to be completed in early 2006. Project scope includes 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 additional refinery modifications after 2006 in order to have the potential to integrate additional volumes of Oil Sands crude oil. Cost estimates for this project are not yet available.

Cost estimates for major projects involve uncertainties and evolve in stages. For a discussion of this process, an update on the status of our significant capital projects in progress and an explanation of "on time and on budget", see page 26 of our MD&A, incorporated by reference herein.

***Other***

*Financing Activities*

In 2005, we entered into a new $600 million credit facility agreement and also renewed $200 million of our available credit and term loan facilities. Our available credit facilities at December 31, 2005 totaled approximately $2.3 billion, of which $1.3 billion was undrawn. 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 2004, we repurchased an undivided interest in our Oil Sands energy service assets previously held under a lease financing arrangement with

a third party for $101 million.

In December 2003 we issued US$500 million of 5.95% unsecured Notes, utilizing the remaining capacity of our US$1 billion shelf prospectus. 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 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 we 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 for the sale of certain proprietary technology. Throughout 2005 $40 million was received for the provision of associated training services. Amounts are being recognized into income over the term of the sale agreement.

During 1999, we completed an offering of preferred securities the proceeds of which totaled Canadian $507 million after issue. We redeemed these securities on March 15, 2004 for the original principal amount plus accrued and unpaid interest as at March 15, 2004. See Note 1(a) to our Consolidated Financial Statements, which is incorporated by reference herein.



*Renewable Energy*

In November 2005, we, along with our joint venture partner Acciona Wind Energy Canada Inc., were selected by the Ontario government to build a 76-megawatt wind power project near Ripley, Ontario. The Ripley Wind Power project is expected to include 38 wind turbines and offset approximately 66,000 tonnes of carbon dioxide annually. The project cost is estimated at approximately $165 million.

In August 2005, we, along with our joint venture partners, a subsidiary of Enbridge Inc. and Acciona Wind Energy Canada Inc., received approval from the Alberta Energy and Utilities Board (EUB) to build a 30-megawatt wind power project near Taber, Alberta called the Chin Chute Wind Power Project. The project is expected to cost approximately $60 million and is scheduled to be commissioned in late 2006. The project plans include approximately 20 wind turbines with the capacity to produce enough zero-emission electricity to offset the equivalent of approximately 88,000 tonnes of carbon dioxide per year.

In September 2004, we, along with our joint venture partners, a subsidiary of Enbridge Inc. and Acciona Wind Energy 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. In 2005 Suncor's share of revenue from its investment in wind power projects was $3 million (2004 - $2 million).

For further information on developments and issues referred to above and other highlights of 2005, 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 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 or near our plant near Fort McMurray, Alberta. Our Oil Sands operations, accounting for virtually all of our conventional and synthetic crude oil production in 2004 and 2005, represent a significant portion of our 2005 capital employed (77%)(6), cash flow from operations(6) (70%) and net earnings (76%). These percentages have been determined excluding the corporate and eliminations segment information.

**Operations**

Our integrated Oil Sands business involves four operations located north of Fort McMurray, Alberta off Highway 63.

1. Bitumen is supplied from a combination of a mining operation using trucks and shovels, an in-situ operation and third party bitumen supply. Commencing in 2004, the Firebag in-situ operation began producing bitumen which was initially sold into the market as diluted bitumen. Beginning in the fourth quarter of 2005 bitumen from Firebag is being upgraded, with only excess production, if any, sold into the market.

2. Extraction facilities recover the bitumen from the oil sands ore that is mined.

3. Heavy oil upgrading converts bitumen into crude oil products.

4. Our energy service needs are primarily met through facilities operated by TransAlta that provide steam and electricity to the operations.

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.

Our in-situ operation uses an extraction technology called Steam Assisted Gravity Drainage ("SAGD") to extract bitumen from oil sands deposits that are too deep to be mined economically. The first step of the SAGD process is to drill a pair of horizontal wells with one well located above the other. Steam produced by our steam generation facilities is injected through the top well into the oil sand. Heated bitumen and condensed steam drain into the bottom well and flow up the well to the surface. The bitumen is pumped to our oil/water separation facilities where the water is removed from the bitumen, treated, and recycled into the steam generation facilities. Naphtha is added to the bitumen to facilitate transportation and the blended bitumen is transported by pipeline to our upgrading facilities. Periodically excess diluted bitumen from our in-situ operations may be sold prior to being upgraded. In 2006, we anticipate upgrading virtually all our extracted bitumen.

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 synthetic crude oil, is either sold directly to customers as sour synthetic crude oil or is further upgraded into sweet synthetic 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.

There is virtually no finding cost associated with synthetic crude oil, the delineation of the resources and development and expansion of production can entail significant outlays of funds. The costs associated

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



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 using the 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.

**Principal Products**

Sales of light sweet synthetic crude oil and diesel represented 54% of Oil Sands consolidated operating revenues in 2005, compared to 67% in 2004. Sales of light sour synthetic crude oil and bitumen represented the remaining 46% of revenues in 2005 compared to 33% in 2004. 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.

| | 2005 | | 2004 | |
|---|---|---|---|---|
| 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/diesel | 88.9 | 54 | 142.8 | 67 |
| Light sour crude oil/bitumen | 76.4 | 46 | 83.5 | 33 |
| Total | 165.3 | 100 | 226.3 | 100 |

2005 sales volumes and sales mix were impacted as a result of the fire at our Oil Sands operation that occurred January 2005. In 2006 we anticipate that approximately 55% of Oil Sands sales will be light sweet synthetic crude and diesel products.

**Principal Markets**

We market our crude oil product blends for sale and distribution to customers in Canada, the United States and periodically, to offshore markets.

**Transportation**

We own and operate a pipeline that transports synthetic crude oil from Fort McMurray, Alberta to Edmonton, Alberta. The pipeline has a capacity of approximately 110,000 bpd.

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 current pipeline capacity for the transport of synthetic crude oil and diluted bitumen from Fort McMurray, Alberta, to Hardisty, Alberta is 170,000 bpd. 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.

In 2005 it was announced that Suncor had entered into a binding memorandum of understanding with Enbridge Pipelines (Athabasca) Inc, Petro-Canada, Total E&P Canada Limited, and ConocoPhillips Surmont Partnership for the transportation of crude oil, on a proposed new pipeline running from Cheecham, Alberta to Edmonton, Alberta. The expected in-service date of the line is targeted for July 1, 2008 with a 25 year term. Initial line capacity is expected to be 350,000 bpd with potential expansion of capacity to 600,000 bpd with the construction of additional pumping facilities. Our initial line commitment is 30,000 bpd. It is expected that the pipeline will provide an enhanced ability to access new markets on the West coast and offshore.

We have a 20 year agreement with TransCanada Pipeline Ventures Limited Partnership 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 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.

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 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 18% of our average 2005 total production (2004 – 13%)) of sour crude from the Oil Sands operation. We began shipping the crude to Koch 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 on twenty-four months notice by either party. Neither party has provided notice of termination at this time.

Under a long term sales agreement with Consumers Co-operative Refineries Limited ("CCRL") we supply 20,000 bpd of sour crude oil production from our Project Millennium expansion facilities. In the fourth quarter of 2005 we signed another contract with CCRL for an additional 12,000 bpd of sour crude oil. Prices for sour crude oil under both of these agreements are set at agreed differentials to market benchmarks.

In 2001, we announced an agreement with Petro-Canada to supply up to 30,000 bpd of diluent to dilute bitumen produced by Petro-Canada. Deliveries under the contract are expected to end when the bitumen processing and sour crude oil supply agreement with Petro-Canada, described below, takes 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 2005, 2004, or 2003.

A portion of our Oil Sands production is used in connection with our Sarnia refining operations. During 2005, the Sarnia refinery processed approximately 4% (2004 - 8%) 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 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 natural 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 in the United States.

In 2005, natural gas and natural gas liquids accounted for approximately 98% of the NG business unit's production (2004 – 97%).

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 and for coal bed methane in the U.S..

**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 315 mmcf/d. Our capacity interest in these gas processing plants is approximately 144 mmcf/d. 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 76% 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. A portion of our natural gas production is also used at our Sarnia, Ontario refining operations.

Approximately 24% 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).

We do not typically enter long-term supply arrangements for our conventional crude oil production, which in 2005 was less than 10,000 bpd. Instead, 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**

Sales of natural gas represented 91% (2004 – 90%) of NG's consolidated operating revenues in 2005, with the remaining 9% (2004 – 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.

| | 2005 | | 2004 | |
|---|---|---|---|---|
| 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 | 31.6 | 91 | 33.3 | 90 |
| Natural gas liquids | 2.4 | 7 | 2.5 | 7 |
| Crude Oil | 0.8 | 2 | 1.0 | 3 |
| Total | 34.8 | 100 | 36.8 | 100 |

**Competitive Conditions**

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

**Seasonal Impacts**

Risk and uncertainties associated with weather conditions can shorten the winter drilling season and impact the spring and summer drilling programs, with increased costs or reduced production.

**Environmental Compliance**

For a description of the impact of environmental protection requirements on NG, refer to "Environmental Regulation and Risk" and "Government Regulation" in the "Risk 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 Ontario. For information about EM&R's energy marketing and trading business, refer to "Energy Marketing and Refining – Canada (EM&R)" under the "Three-Year Highlights", "Energy Marketing & Trading" heading.

As a marketing channel for our refined products, EM&R's Ontario retail network generated approximately 57% of EM&R's total 2005 sales volume of 96,000 bpd. The retail networks are comprised of 275 Sunoco-branded retail service stations, 28 Sunoco-branded Fleet Fuel Cardlock sites, and two 50% retail joint venture(7) businesses that operate 149 Pioneer-branded retail service stations, 50 UPI-branded retail service stations and 14 UPI bulk distribution facilities for rural and farm fuels. Approximately 39% of EM&R's refined product sales in 2005 were wholesale and industrial sales. Sun Petrochemicals Company

(7) Pioneer Group Inc., is an independent company that Suncor has a 50% joint venture partnership with. UPI Inc. is a 50% joint venture Suncor has with GROWMARK Inc., a Midwest U.S. retail farm supply and grain marketing cooperative.

(SPC), a 50% joint venture between a Suncor subsidiary and a Toledo, Ohio-based refinery, generated the remaining 4% of sales.

**Procurement of Feedstocks**

The Sarnia refinery uses both synthetic and conventional crude oil. In 2005, the Sarnia refinery procured approximately 16% (2004 – 41%) of its synthetic crude oil feedstock from our Oil Sands production. In 2005, 62% (2004 – 66%) 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. During 2005, as a result of the fire at Oil Sands, EM&R was forced to purchase additional third party synthetic crude oil to meet customer demand.

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 2005 averaged approximately 90,700 bpd (2004 – 94,300 bpd). Sales volumes are higher than crude oil capacity due to often running more than 70,000 bpd, incremental volume from the addition of feedstocks in the production process, purchases of third-party products for resale and sales from joint venture partners that are not from production. 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 have 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 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 improvements and upgrades, it can continue to be operated economically and safely for up to 10 years. A range of replacement options for the catcracker were identified during a review in 2005. Further analysis of these options during 2006 is required to finalize the preferred option for the catcracker for the



next 10 years.

During 2005, EM&R completed scheduled outages and slowdowns throughout the refinery's plants, which affected production as expected. However, production in the third quarter was slightly lower than normal due to a heater fire and utilization rates in the fourth quarter were lower due to a power failure causing an unplanned catcracker outage.

Overall, crude utilization averaged 95% for the year, compared to 100% in 2004. 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 | 2005 | 2004 |
|---|---|---|
| Average daily crude input (barrels per day) | 66,700 | 69,900 |
| Average crude utilization rate (%)(1) | 95 | 100 |
| Average cracking capacity utilization (%)(2) | 95 | 91 |

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 68% of EM&R's consolidated operating revenues in 2005, compared to 72% in 2004. 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.

| | 2005 | | 2004 | |
|---|---|---|---|---|
| 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 | 4.5 | 27 | 4.6 | 29 |
| Joint Ventures | 2.8 | 15 | 3.1 | 16 |
| Other | 1.1 | 7 | 1.0 | 9 |
| Jet Fuel | 0.9 | 4 | 0.9 | 4 |
| Diesel | 3.3 | 15 | 3.1 | 14 |
| Sub-total – Transportation Fuels | 12.6 | 68 | 12.7 | 72 |
| Petrochemicals | 0.7 | 4 | 0.8 | 6 |
| Heating Fuels | 0.4 | 3 | 0.4 | 3 |
| Heavy Fuel Oils | 1.0 | 2 | 0.7 | 1 |
| Other | 0.5 | 2 | 0.8 | 3 |
| Total Refined Products | 15.2 | 79 | 15.4 | 85 |
| Other Non-Refined Products(1) | | 3 | | 3 |
| Energy Marketing & Trading | | 18 | | 12 |
| Total% | | 100 | | 100 |

Note:

(1) Includes ancillary revenues



**Principal Markets**

Approximately 57% (2004 – 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 2005, this network was comprised of:

275 (2004 – 278) Sunoco-branded retail service stations
149 (2004 – 147) Pioneer-operated retail service stations
50 (2004 – 52) UPI-operated retail service stations and a network of 14 bulk distribution facilities for rural and farm fuels
28 (2004 – 23) Sunoco branded Fleet Fuel Cardlock sites

UPI Inc. 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.

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

Approximately 39% (2004 – 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, Quebec.

EM&R markets toluene, mixed xylenes, orthoxylene and other petrochemicals, primarily in Canada and the U.S., through Sun Petrochemicals Company ("SPC"). EM&R has a 50% interest in SPC, a petrochemical marketing joint venture that markets products from our Sarnia, Ontario 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, Ontario.

EM&R's share of total refined product sales in its primary market of Ontario was approximately 19% in 2005 (2004 – 19%). Transportation fuels accounted for 82% of EM&R's total sales volumes in 2005 (2004 – 82%); and petrochemicals accounted for 4% (2004 – 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 54% of this capacity in 2005 (2004 – 55%). Total utilization of the pipeline was 84% in 2005 (2004 - 88%).

EM&R also has pipeline access, subject to availability, to petroleum markets in the Great Lakes region of the United States by way of 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 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 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 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 and expanded via acquisition of the Colorado Refining Company on May 31, 2005, operates a pipeline transportation, refining and marketing business primarily in Colorado and Wyoming. The Denver area refineries, located in Commerce City, Colorado, have a combined crude distillation capacity of 90,000 bpd. The majority of the refined products from the Denver refinery are distributed in Colorado.

Approximately 18% of R&M’s petroleum products sales in 2005 (2004 – 24%) were sold through a distribution network in Colorado that sells gasoline and diesel fuel to retail customers. Approximately 70% in 2005 (2004 – 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 comprised the remaining 12% of R&M’s refined product sales volumes for 2005 (2004 – 16%).

**Procurement of Feedstocks**

The Denver refining operation uses both conventional and synthetic crude oil. Approximately one-third of the 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 multi-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.

**Refining Operations**

Upgrading units at the refining operation include a 27,000 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 2005 averaged approximately 86,200 bpd (13,700 $m^3$ per day) compared to 58,500 bpd (9,300 $m^3$) in 2004.

The Denver area refining operation is a high conversion operation 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 approximately one-third heavy, high sulphur crude. Overall, crude utilization averaged 98% in 2005 (2004 – 92%). The following chart sets out daily crude input, average refinery utilization rates and cracking capacity utilization for 2005 and 2004.



| Denver Refining Capacity | 2005 | 2004 |
|---|---|---|
| Average daily crude input (barrels per day)(1) | 76,300 | 55,400 |
| Average crude utilization rate (%)(2) | 98 | 92 |

| | | |
|---|---|---|
| Average fluidized catalytic cracker capacity utilization rate (%)(3) | 89 | 88 |

Notes:

(1) 30,000 bpd Valero refinery capacity acquired May 31, 2005.

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

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

**Principal Products**

Sales of gasoline and other transportation fuels represented 90% of R&M's consolidated operating revenues in 2005 (2004 – 85%). 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 2005.

| | 2005 | | 2004 | |
|---|---|---|---|---|
| **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 | 11 | 0.7 | 8 |
| Other | 6.2 | 46 | 3.8 | 44 |
| Jet Fuel | 0.8 | 6 | 0.5 | 7 |
| Diesel | 3.3 | 27 | 2.2 | 26 |
| Total Transportation Fuels | 11.0 | 90 | 7.2 | 85 |
| Asphalt | 1.6 | 4 | 1.5 | 8 |
| Other | 1.1 | 4 | 0.6 | 3 |
| Total Refined Product Sales | 13.7 | 98 | 9.3 | 96 |
| Other Non-Refined Product(1) | | 2 | | 4 |
| | | 100 | | 100 |

Note:

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

**Principal Markets**

Approximately 18% 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 5% of R&M's sales volumes; and
- Supply agreements with 164 Phillips 66 ® branded marketer outlets throughout the state of Colorado, which account for approximately 13% 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 refining operation also supplies all of its asphalt production to SemMaterials, L.P.. Asphalt sales made up about 12% of R&M's total 2005 sales volumes (2004 – 16%).

Approximately 70% of R&M's total sales volumes are sold to industrial, commercial, wholesale, and refining customers, primarily in Colorado, of which approximately 15% was sold under a long-term supply agreement with ConocoPhillips and 17% under a long-term supply agreement with Valero. Under the ConocoPhillips agreement, R&M supplies ConocoPhillips with gasoline and distillates, and 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. In connection with the purchase of CRC, R&M entered into a three year offtake agreement with Valero which expires in May 2008. Valero became R&M's largest customer following the CRC acquisition.

R&M estimates its sales of total light fuels refined product in 2005 represented a market share, in its primary market of Colorado, of approximately 35% (2004 – 23%). Within this market, R&M's Phillips 66 ® - branded sites represent a 18% market share (2004 – 24%).

**Transportation and Distribution**

Approximately two-thirds of crude oil processed at the Denver refining operation is transported via pipeline, with the remainder supplied via truck.

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 the Centennial pipeline. The other 35% owned by another area refiner. The Rocky Mountain crude system capacity 31,100 bpd in 2005 for the Guernsey to Cheyenne leg of the pipeline and 60,500 bpd for the Cheyenne to Denver leg of the pipeline. In 2005, the Rocky Mountain Crude system utilized approximately 115% (2004 – 109%) of capacity with average throughput of 35,400 bpd (2004 – 34,200 bpd) in the Guernsey to Cheyenne leg of the pipeline, and 70,150 bpd (2004 - 65,200 bpd) in the higher capacity Cheyenne to Denver leg. During the same period, the Centennial pipeline utilized approximately 102% (2004 – 97%) of capacity, with an average throughput of approximately 62,500 bpd (2004 – 59,100 bpd).

R&M has both truck and rail loading racks at the Denver area refineries with product loading capacity in excess of 30,000 bpd, 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 Factors” section of this Annual Information Form.



**Environmental Compliance**

Due to increasingly stringent regulations regarding water discharges, the need to improve water treatment ability at our Denver refining operation we will require additional water treating equipment for the discharge of process waste water. It is estimated that this will cost approximately Cdn$19 to $23 million (US$16 to $20 million) and be completed in the 2006 to 2010 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 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 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, 2005 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, 2005.

## RESERVES ESTIMATES

We are a Canadian issuer 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”). 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 and net proved and probable mining reserves. The estimates of our gross and net mining reserves are based in part on the current mine plan and estimates of extraction recovery and upgrading yields. We report mining reserves as barrels of synthetic crude oil based on a net coker, or synthetic crude oil yield from bitumen of 80%. During 2005, we reached an agreement with the Government of Alberta finalizing the terms of our option to transition to the generic bitumen based royalty regime commencing in 2009, allowing us to prepare an estimate of our net mining reserves. The estimate of our net mining reserves reflect the relative value of Alberta Crown and freehold royalty burdens under constant December 31$^{st}$ bitumen pricing and assumes Suncor will elect to transfer to a bitumen based Crown royalty effective at the beginning of 2009 (See “REQUIRED U.S. OIL AND GAS AND MINING DISCLOSURE – Proved and Probable Oil Sands Mining Reserves” for both gross and net, proved and probable mining reserves). Our Firebag in-situ leases are subject to Crown royalty based on bitumen, rather than synthetic crude oil (for a full discussion of our oil sands Crown royalties, see “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 and net 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%); and

(b) Gross and net 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 at 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 aggregation purposes only, to barrels of synthetic crude oil based on a net coker or synthetic crude oil yield from bitumen of 80%.

Accordingly, our voluntary disclosures of reserves from our Firebag in-situ leases will differ from our required U.S. disclosure in four ways. Reserves from our Firebag in-situ leases under our voluntary disclosure:

(a) are disclosed on a gross basis as well as the required net basis under U.S. disclosure requirements;

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

(c) are evaluated based on 2005 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; and

(d) include proved plus probable reserves, rather than proved reserves only under U.S. disclosure requirements.

Under the U.S. disclosure requirements described above, our Firebag in-situ reserves were determined to be entirely uneconomic at December 31, 2004. In 2005, Constant Cost and Pricing assumptions were again applied to assess economic viability of our in-situ reserves. This assessment resulted in the rebooking of proved reserves at December 31, 2005 (See "REQUIRED U.S. OIL AND GAS AND MINING DISCLOSURE - Proved Conventional Oil and Gas Reserves").

Under our voluntary disclosure, using 2005 Annual Average Differential Pricing, our Firebag in-situ reserves were also determined to be economic and accordingly, were disclosed under "VOLUNTARY OIL SANDS RESERVES DISCLOSURE - Estimated Gross and Net Proved and Probable Oil Sands Reserves Reconciliations".

Comparisons of reserve estimates under required U.S. Oil and Gas Mining Disclosure and Voluntary Oil Sands Reserve Disclosure will show material differences based on the pricing assumptions used, whether the reserves are reported as barrels of bitumen or barrels of synthetic crude oil, whether probable reserves are included, and whether the reserves are reported on a gross or net basis.

All of our reserves have been evaluated as at December 31, 2005 by independent petroleum consultants, GLJ Petroleum Consultants Ltd. ("GLJ"). In reports dated February 21, 2006 ("GLJ Oil Sands Reports"), GLJ evaluated our proved and probable reserves on our oil sands mining and Firebag in-situ leases, pursuant to both U.S. disclosure requirements using Constant Cost and Pricing assumptions, and pursuant to CSA Staff Notice 51-315, using 2005 Annual Average Differential Pricing assumptions.

Estimates in the GLJ Oil Sands Reports consider recovery from leases for which regulatory applications have been submitted and no anticipated impediment to the receipt of regulatory approval is expected. 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 or likely impediments to the receipt of pending regulatory approval, project implementation commitments, detailed design estimates, detailed reservoir studies, demonstrated commercial success of analogous commercial projects and drill density. Our proved reserves are delineated to within 80 acre spacing with 3D seismic control (or 40 acre spacing without 3D seismic control) while our probable reserves are delineated to within 320 acre spacing with 3D seismic control (or 160 acre spacing without 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 have not yet received final approval from our Board.

In a report dated February 21, 2006 ("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, 2005.

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

Net reserves represent Suncor's undivided percentage interest in total reserves after deducting Crown Royalties, freehold and overriding royalty interests. Reserve estimates are based on assumptions about future prices, production levels, operating costs and capital expenditures. These assumptions reflect market conditions, as required, at December 31, 2005 which could differ significantly from other points in time throughout the year, or future periods. These market conditions and assumptions can materially impact the estimation of net reserves.

## REQUIRED U.S. OIL AND GAS AND MINING DISCLOSURE

### Proved and Probable Oil Sands Mining Reserves

| Millions of barrels of synthetic crude oil (1) | Proved | | Probable | | Proved & Probable | |
|---|---|---|---|---|---|---|
| | Gross (2) | Net (3) | Gross (2) | Net (3) | Gross (2) | Net (3) |
| December 31, 2004 | 939 | 916 | 847 | 837 | 1,786 | 1,753 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Revisions of previous estimates | 645 | 575 | (439) | (438) | 206 | 137 |
| Extensions and discoveries | — | — | 488 | 463 | 488 | 463 |
| Production | (56) | (51) | — | — | (56) | (51) |
| **December 31, 2005** | **1,528** | **1,440** | **896** | **862** | **2,424** | **2,302** |

Notes:

(1) Synthetic crude oil reserves are based upon a net coker, or synthetic crude oil yield from bitumen of 80% (2004 – 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) Net mining reserves reflect the relative value of Crown, freehold and overriding royalty burdens under constant December 31st pricing and assumes we will elect to transfer to a bitumen based Crown royalty effective at the beginning of 2009.



**Significant Mining Leases**

| Interest Held | Description | Gross Acres | Expiry Date | Retention Conditions |
|---|---|---|---|---|
| Leases: | 7279080T19 | 18,541 | n/a | (1) |
| | 7597030T11 | 2,454 | n/a | (1) |
| | 7280100T25 | 19,654 | n/a | (1) |
| | 7387060T04 | 4,469 | n/a | (1) |
| | 7279120092 | 1,600 | n/a | (1) |
| | 7280060T23 | 36,526 | n/a | (1) |
| | 7498050014 | 240 | May 27, 2019 | (2) |
| | 7405080347 | 5,693 | Aug. 24, 2020 | (2) |
| | 7405030690 | 633 | Mar. 23, 2020 | (2) |
| | 7405010854 | 22,773 | Jan. 26, 2020 | (2) |
| | 7405010853 | 22,773 | Jan. 26, 2020 | (2) |
| | 7400120007 | 22,773 | Dec. 13, 2015 | (2) |
| | 7405080346 | 5,060 | Aug. 24, 2020 | (2) |
| | 7401100029 | 10,120 | Oct. 17, 2016 | (2) |
| Fee Lots: | 1 | 1,894 | n/a | n/a |
| | 2 | 1,972 | n/a | n/a |
| | 3 | 1,967 | n/a | n/a |
| | 4 | 1,886 | n/a | n/a |
| | 5 | 1,881 | n/a | n/a |
| | 6 | 1,483 | n/a | n/a |
| Total | | 184,392 | | |

(1) These producing leases can be retained indefinitely so long as agreed minimum levels of production are maintained.

(2) Annual lease rentals are required to maintain these leases until the indicated expiry dates for the primary term of the lease. Leases can be retained after these dates if:

a. they are in production and sustain agreed minimum levels of production; or
b. retained indefinitely if escalating rents are paid. Depending on area, such rents range from $3/acre/year in in-situ areas to $7/acre/year in surface mining zones and double every three years to a maximum of $96/acre/year in in-situ zones and $224/acre/year in surface mining areas.



**Oil Sands Mining Operating Statistics**

The following table sets out certain operating statistics for our 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”.

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| Total mined volume (1) | | | |
| millions of tones | 313.7 | 371.2 | 316.9 |
| Mined volume to tar sands ratio(1) | 32.0% | 41.6% | 48.1% |
| Tar sands mined | | | |
| millions of tones | 100.5 | 154.3 | 152.5 |
| Average bitumen grade (weight %) | 12.2% | 11.2% | 11.3% |

| | | | |
|---|---|---|---|
| Crude bitumen in mined tar sands | | | |
| millions of tones | 12.3 | 17.3 | 17.2 |
| Average extraction recovery % | 92.6% | 91.9% | 92.0% |
| Crude bitumen production | | | |
| millions of cubic meters(2) | 11.4 | 15.7 | 15.7 |
| Average upgrading yield % (net) | 78.2% | 79.1% | 79.4% |
| Gross synthetic crude oil produced | | | |
| Thousands of barrels per day(3) | 152.2 | 215.6 | 216.6 |

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. Note, in 2004 and prior years, production equaled our “base operations” production statistics as included in the operating summaries filed with our annual financial statements. In 2005 and subsequent years, bitumen production from Firebag is upgraded and included in the base operations production. Therefore the mining production reported above will no longer agree to the operating statistics.

**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(1)**

**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) (2),(3),(4) | Natural Gas business: Crude Oil and Natural Gas Liquids (millions of barrels) | Total (millions of barrels) | Natural Gas business: Natural Gas (billions of cubic feet) |
|---|---|---|---|---|
| December 31, 2002 | 151 | 10 | 161 | 516 |
| Revisions of previous estimates (5) | 273 | (2) | 271 | (49) |
| Purchases of minerals in place | — | — | — | — |
| Extensions and discoveries | — | 1 | 1 | 39 |
| Production | — | (1) | (1) | (50) |
| Sales of minerals in place | — | — | — | — |
| December 31, 2003 | 424 | 8 | 432 | 456 |
| Revisions of previous estimates (5) | (420) | 1 | (419) | — |
| Purchases of minerals in place | — | — | — | 14 |
| Extensions and discoveries | — | — | — | 30 |
| Production | (4) | (1) | (5) | (54) |
| Sales of minerals in place | — | — | — | — |
| December 31, 2004 | —(3) | 8 | 8 | 446 |
| Revisions of previous estimates (5) | 639 | — | 639 | 14 |
| Purchases of minerals in place | — | — | — | — |
| Extensions and discoveries | — | — | — | 40 |
| Production | (7) | (1) | (8) | (50) |
| Sales of minerals in place | — | — | — | (1) |
| December 31, 2005 | 632 | 7 | 639 | 449 |
| | | | | |
| Proved Developed | | | | |
| | | | | |
| December 31, 2002 | — | 8 | 8 | 426 |
| December 31, 2003 | 92 | 6 | 98 | 403 |
| December 31, 2004 | — | 7 | 7 | 385 |
| December 31, 2005 | 137 | 7 | 144 | 387 |

Notes:

(1) Our undivided percentage interest in reserves, after deducting Crown royalties, freehold royalties and overriding royalty interests. Our Firebag leases are only subject to Crown royalties.

(2) Although we are subject to Canadian disclosure rules in connection with the reporting of our 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 45.

(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. Under 2005 Constant Cost and Pricing we have rebooked our proved reserves.

(4) We have the option of selling the bitumen production from these leases or upgrading the bitumen to synthetic crude oil. With the completion of upgrading expansion projects during 2005, all bitumen is expected to be processed into synthetic crude oil in the future.

(5) Includes total infill drilling of 2005 - 23 billion cubic feet (bcf), (2004 – 20 bcf; 2003 – 15 bcf).

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, 2005. 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, 2005 | 2004 |
|---|---|---|
| Proved properties | 3,268 | 1,414 |
| Unproved properties | 159 | 1,399 |
| Other support facilities and equipment | 15 | 18 |
| Total cost | 3,442 | 2,831 |
| Accumulated depreciation and depletion | (852) | (697) |
| Net capitalized costs | 2,590 | 2,134 |

Note:

(1) Capitalized costs do not include costs related to the associated upgrading expansion projects.

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

| ($ millions) | For the years ended December 31, 2005 | 2004 | 2003 |
|---|---|---|---|
| Property acquisition costs | | | |
| Proved properties | 1 | 32 | — |
| Unproved properties | 9 | 10 | 29 |
| Exploration costs | 148 | 78 | 46 |
| Development costs | 552 | 545 | 489 |
| Asset retirement obligations | 4 | 27 | 8 |
| Total capital and exploration expenditures | 714 | 692 | 572 |

Note:

(1) Costs incurred do not include costs related to associated upgrading expansion projects.

**Results of Operations for Oil and Gas Production**

| ($ millions) | For the years ended December 31, 2005 | 2004 | 2003 |
|---|---|---|---|
| Revenues | | | |
| Sales to unaffiliated customers | 670 | 469 | 319 |
| Transfers to other operations | 52 | 64 | 61 |
| | 722 | 533 | 380 |
| Expenses | | | |
| Production costs | 213 | 122 | 44 |
| Depreciation, depletion and amortization | 145 | 130 | 76 |
| Exploration | 66 | 57 | 86 |
| Gain on disposal of assets | (12) | (19) | (12) |
| Other related costs | 39 | 73 | 37 |
| | 451 | 363 | 231 |
| Operating profit before income taxes | 271 | 170 | 149 |
| Related income taxes | (98) | (48) | (40) |

| | | | |
|---|---|---|---|
| Results of operations | 173 | 122 | 109 |



**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:

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| Year end natural gas price (AECO- CDN$/GJ) | 10.22 | 7.17 | 5.28 |
| Year end crude oil price (WTI US$/bbl) | 59.45 | 43.26 | 32.50 |
| Year end light/heavy crude oil differential, WTI at Cushing less LLB at Hardisty (US$/bbl) | 26.35 | 22.71 | 10.34 |

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;
- 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; and
- Whether we elect to move to the generic bitumen based Crown royalty effective 2009.

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) | 2005 | 2004 | 2003 |
|---|---|---|---|
| Future cash flows | 16,444 | 3,355 | 11,655 |
| Future production and development costs | (11,886) | (704) | (5,141) |
| Other related future costs | (464) | (367) | (391) |
| Future income tax expenses | (1,216) | (460) | (1,694) |
| Subtotal | 2,878 | 1,824 | 4,429 |
| *Discount at 10% | (1,214) | (750) | (2,578) |
| Standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves after income taxes | 1,664 | 1,074 | 1,851 |

**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) | 2005 | 2004 | 2003 |
|---|---|---|---|
| Balance, beginning of year | 1,074 | 1,851 | 1,727 |
| Sales and transfers of oil and gas produced, net of production costs | (456) | (359) | (306) |
| Net changes in prices and production costs | 737 | (1,786) | (1,010) |
| Changes in estimated future development costs | (573) | 14 | (13) |
| Extensions, discoveries and improved recovery, less related costs | 162 | 131 | 95 |
| Development costs incurred during the period | 557 | 524 | 329 |
| Revisions of previous quantity estimates | 440 | (47) | 712 |
| Purchases of reserves in place | — | 32 | — |

| | | | |
|---|---|---|---|
| Sale of reserves in place | (4) | — | — |
| Accretion of discount | 125 | 245 | 260 |
| Net changes in income taxes | (470) | 426 | 272 |
| Other related costs | 72 | 43 | (215) |
| Balance, end of year | 1,664 | 1,074 | 1,851 |

**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, | 2005 | 2004 | 2003 |
|---|---|---|---|
| Crude Oil and Bitumen ($/bbl) (3) | 45.86 | 37.71 | 40.29 |
| NGL ($/bbl) | 50.70 | 42.82 | 36.08 |
| Natural Gas ($/mcf) | 8.57 | 6.70 | 6.42 |

Notes:

(1) Production is based in Western Canada.

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

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



*Production Costs*

| For the year ended December 31, ($ per BOE of gross production) | 2005 | 2004 | 2003 |
|---|---|---|---|
| Average production (lifting) cost of conventional crude oil and gas(1) | 10.86 | 7.08 | 3.48 |

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 2003 production costs only include the costs associated with Suncor's Natural Gas business. Since 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, 2005 number of wells | Gross(1) | Net(2) | Gross(1) | Net(2) | Gross(1) | Net(2) |
| Alberta | 72 | 55 | 338 | 207 | 410 | 262 |
| British Columbia | 24 | 11 | 105 | 43 | 129 | 54 |
| Total | 96 | 66 | 443 | 250 | 539 | 316 |

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*

| | Developed | | Undeveloped(1) | | Total | |
|---|---|---|---|---|---|---|
| As at December 31, 2005 (thousands of acres) | Gross(1) | Net(2) | Gross(1) | Net(2) | Gross(1) | Net(2) |
| Canada | | | | | | |
| Natural Gas | 940 | 430 | 640 | 430 | 1,580 | 860 |
| Firebag | 2 | 2 | 287 | 287 | 289 | 289 |
| Total Canada | 942 | 432 | 927 | 717 | 1,869 | 1,149 |

| | | | | | | |
|---|---|---|---|---|---|---|
| USA | | | | | | |
| Natural Gas | — | — | 153 | 95 | 153 | 95 |
| Total | 942 | 432 | 1,080 | 812 | 2,022 | 1,244 |

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*

| | Net Exploratory | | | Net Development | | |
|---|---|---|---|---|---|---|
| **For the year ended December 31, 2005 (number of net wells)** | **Productive** | **Dry Holes** | **Total** | **Productive** | **Dry Holes** | **Total** |
| Canada | | | | | | |
| Natural Gas | 8 | 3 | 11 | 18 | 4 | 22 |
| Firebag | — | — | — | 10 | — | 10 |
| United States | — | 1 | 1 | — | — | — |
| Total | 8 | 4 | 12 | 28 | 4 | 32 |

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

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

At December 31, 2005, we were participating in the drilling of 49 gross (32 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 85 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 had previously entered into 36,000 bpd of crude oil swap contracts to hedge Canadian dollar revenues and cash flows from potential changes in commodity pricing. These contracts expired during 2005. During the third quarter of 2005, we entered into new agreements covering 7,000 bpd spanning January 1, 2006 through December 31, 2007. Prices for these barrels are fixed within a range of US$50 per barrel to an average of about US$93 barrel WTI. We have continued to enter into crude oil hedges during the first quarter of 2006. As at March 1, 2006, crude oil hedges totaling 50,000 bpd of production were outstanding for the remainder of 2006 and 2007. Prices for these barrels are fixed within a range of US$50/bbl to an average of US$91.70/bbl. We intend to consider additional costless collars of up to 30% of our crude oil production if strategic opportunities are available. For further particulars of these hedging arrangements, see the information under the heading “Derivative Financial Instruments”, under “Risk Factors Affecting Performance” in the “Suncor Corporate Overview and Strategic Priorities” section of our MD&A, and Note 6 to our 2005 Consolidated Financial Statements, which note is incorporated by reference herein.



## VOLUNTARY OIL SANDS RESERVES DISCLOSURE

**Oil Sands Mining and Firebag In-Situ Reserves Reconciliation**

The following tables set out, on a gross and net basis(8), a reconciliation of our proved and probable reserves of synthetic crude oil from our Oil Sands mining leases and bitumen, converted to synthetic crude oil for comparison purposes only, from our in-situ Firebag leases, from

December 31, 2004 to December 31, 2005, based on the GLJ Oil Sands Reports, in accordance with CSA Staff Notice 51-315, using 2005 Annual Average Differential Pricing assumptions.

(8) 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) | | | Firebag In-situ Leases(1),(3) | | | Total Mining and In-situ(3) |
|---|---|---|---|---|---|---|---|
| | Proved | Probable | Proved & Probable | Proved(3) | Probable(3) | Proved & Probable | Proved & Probable |
| December 31, 2004 | 939 | 847 | 1,786 | 494 | 1,900 | 2,394 | 4,180 |
| Revisions of previous estimates | 645 | (439) | 206 | 73 | (131) | (58) | 148 |
| Improved recovery | — | — | — | — | 368 | 368 | 368 |
| Extensions and discoveries | — | 488 | 488 | — | — | — | 488 |
| Production | (56) | — | (56) | (6) | — | (6) | (62) |
| December 31, 2005 | 1,528 | 896 | 2,424 | 561 | 2,137 | 2,698 | 5,122 |

**Estimated Net Proved and Probable Oil Sands Reserves Reconciliation**

| (millions of barrels of synthetic crude oil)(1) | Oil Sands Mining Leases(1)(2) | | | Firebag In-situ Leases(1),(3) | | | Total Mining and In-situ(3) |
|---|---|---|---|---|---|---|---|
| | Proved | Probable | Proved & Probable | Proved(3) | Probable(3) | Proved & Probable | Proved & Probable |
| December 31, 2004 | 916 | 837 | 1,753 | 457 | 1,714 | 2,171 | 3,924 |
| Revisions of previous estimates | 575 | (438) | 137 | 105 | (38) | 67 | 204 |
| Improved recovery | — | — | — | — | 353 | 353 | 353 |
| Extensions and discoveries | — | 463 | 463 | — | — | — | 463 |
| Production | (51) | — | (51) | (6) | — | (6) | (57) |
| December 31, 2005 | 1,440 | 862 | 2,302 | 556 | 2,029 | 2,585 | 4,887 |

Notes:

(1) Synthetic crude oil reserves are based upon a net coker, or synthetic crude oil yield from bitumen of 80% for reserves under Oil Sands mining and 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. Accordingly, these bitumen reserves are converted to synthetic crude oil for aggregation purposes.

(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. Net mining reserves reflect the relative value of Crown, freehold and overriding royalty burdens under constant December 31st pricing and assumes we will elect to transfer to a bitumen based Crown royalty effective at the beginning of 2009.

(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 four ways. Reserves from our Firebag in-situ leases under our voluntary disclosure:

(a) are disclosed on a gross basis as well as the required net basis under U.S. disclosure requirements;

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

(c) are 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; and

(d) include proved plus probable reserves, rather than proved reserves only under U.S. disclosure requirements. 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 our in-situ reserves into a consolidated total for our Oil Sands business. As a result, our Firebag in-situ estimates in the above tables 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, | |
|---|---|---|
| | 2005 | 2004 |
| Oil Sands | 2,787 | 2,523 |
| Natural Gas | 214 | 202 |
| Energy Marketing & Refining – Canada | 638 | 629 |
| Marketing & Refining – U.S.A | 662 | 630 |
| Corporate | 851 | 621 |
| Total (1) | 5,152 | 4,605 |

Notes:

(1) 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. A three year agreement was signed in 2005 with the Sarnia employee association that will be renegotiated in 2008. 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 United Steel Workers (USW) union, represents approximately 150 employees at R&M's Denver area west plant, originally acquired from ConocoPhillips in August 2003. A contract extension was ratified in 2005 and will expire in January 2009. The same union represents approximately 87 employees at the east plant, acquired from Valero in May, 2005. In February 2006, the east plant union voted to merge the east plant workers into the existing collective bargaining agreement at the west plant. The merged contract becomes effective in March 2006 and will expire in January 2009.

## RISK 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 on 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.

During the third quarter of 2005, we resumed our strategic crude oil hedging program, permitting us to fix a price or range of prices for a percentage of our total production of crude oil for specified periods of time. During the third quarter of 2005, we entered into new agreements covering 7,000 bpd spanning January 1, 2006 through December 31, 2007. Prices for these barrels are fixed within a range of US$50 per barrel to an average of about US$93 barrel WTI. We have continued to enter into crude oil hedges during the first quarter of 2006. As at March 1, 2006, crude oil hedges totaling 50,000 bpd of production were outstanding for the remainder of 2006 and 2007. Prices for these barrels are fixed within a range of US$50/bbl to an average of US$91.70/bbl. We intend to consider additional costless collars of up to 30% of our crude oil production if strategic opportunities are available.

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, and in the case of R&M, asphalt. 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, the new coker unit, 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; 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.

Cost estimates for major projects involve uncertainties and evolve in stages. For a discussion of this process, an update on the status of our significant capital projects in progress and an explanation of “on time and on budget”, see page 26 of our MD&A, incorporated by reference herein.

*Labour and Materials Supply.* With the expansion of the industry and the impact of new entrants to the business, risks in the form of availability/competition for skilled labour and materials supply continue to build. Although these risks are not exclusive to our Oil Sands operation, the increased demands on the Fort McMurray, Alberta infrastructure (for example, housing, roads and schools) and a commuting workforce have heightened concerns. Our ability to operate effectively, and complete major projects on time and on budget are significantly impacted by these risks. Risks associated with completion of significant capital projects, are discussed in “Major Projects” above.



*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 2005, the Oil Sands business accounted for approximately 83% (86% in 2004) of our upstream production, 76% (81% in 2004) of our net earnings and 70% (76% in 2004) 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 further 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 North American conventional and synthetic sweet and sour crude oil producers. With current expansion plans there are risks associated with the delivery of our products to market.

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 one million bpd in 2004 to approximately 2.0 million bpd by 2010(9). Increasing industry consolidation, a global focus on oil sands and additional competitors with financial capacity has: i) materially increased the supply of bitumen and synthetic crude oil and other competing crude oil products in the marketplace; ii) exponentially increased land values and availability of new leases; and iii) placed stress on availability of all resources required to run the Oil Sands operation. If we are unable to transport our produced crude oil products, production levels may be adversely affected.

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 refining and retail 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

(9) Alberta Government – Talk About Oil Sands



new product markets, they could be exposed to margin risk and volatility from either cost and/or selling price fluctuations.

Breach of confidentiality could also place us at competitive risk if confidential operational information or proprietary intellectual property was improperly disclosed.

*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 2005 our average natural gas reservoir decline rates were in the 24% range (2004 – 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(10) 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, IT systems and related data and control systems, 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. Risks associated with access to skilled labour to support our operations in a safe and effective manner are also discussed in "Labour and Materials Supply", above.

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, fires, 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

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



of product, slowdowns due to equipment failures, unavailability of feedstock, price and quality of feedstock, or other accidents.

We are also subject to operational risks such as sabotage, terrorism, trespass, related damage to remote facilities, theft and malicious software or network attacks.

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 10(b) to our 2005 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, 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 2005 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, 2005 ($14 million as at December 31, 2005) 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 irrevocable letters of credit equal to approximately $87 million, representing security for the estimated cost of reclamation activities up to the end of December 2005. 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 2005. 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, or subject the Company to fines and penalties potentially having a material impact on revenues and earnings.

The R&M business is subject to Consent Decrees with the United States Environmental Protection Agency, the United States Department of Justice and the State of Colorado. For a discussion of these consent decrees and the related obligations, see the information under the R&M section of "Narrative Description of the Business" in this Annual Information Form. The Company is subject to the risk that failure to meet its obligations or the deadlines under these Consent Decrees 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, and/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, taxes including income taxes, 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, 2005 is derived from our 2005 Consolidated Financial Statements. Our consolidated financial statements for each of the years in the three-year period ended December 31, 2005 have been audited by PricewaterhouseCoopers LLP, Chartered Accountants. The information set forth below should be read in conjunction with our MD&A and our 2005 Consolidated Financial Statements.

| | Year ended December 31 | | |
|---|---|---|---|
| **($ millions except per share amounts)** | **2005** | **2004** | **2003** |
| Revenues | 11,086 | 8,665 | 6,611 |
| Net earnings | 1,245 | 1,088 | 1,087 |
| Per common share (undiluted) | 2.73 | 2.40 | 2.42 |
| Per common share (diluted) | 2.67 | 2.36 | 2.26 |
| Cash flow from operations | 2,476 | 2,013 | 2,040 |
| Capital, acquisition and exploration expenditures | 3,186 | 1,825 | 1,708 |

| ($ millions) | Year ended December 31, 2005 | 2004 | 2003 |
|---|---|---|---|
| Total assets | 15,351 | 11,841 | 10,540 |
| Long-term debt | 3,007 | 2,217 | 2,934 |
| Accrued liabilities and other(1) | 1,005 | 749 | 616 |
| Shareholders' equity | 6,130 | 4,921 | 3,893 |

Note:

(1) See Note 7 to our 2005 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) | 2005 | % | 2004 | % |
|---|---|---|---|---|
| Transportation fuel sales | 5,459 | 49 | 4,337 | 50 |
| Crude oil sales | 3,203 | 29 | 3,064 | 35 |
| Other (2) | 2,422 | 22 | 1,261 | 15 |
| **Total** | 11,084(1) | 100 | **8,662**(1) | 100 |

Note:

(1) Excludes interest income.
(2) Includes insurance proceeds of $572 million



**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.

The following table sets forth the per share amount of dividends we paid to shareholders during the last three years.

| | Year Ended December 31, 2005 | 2004 | 2003 |
|---|---|---|---|
| Common Shares cash dividends | $ 0.24 | $ 0.23 | $ 0.1925 |
| Dividends paid in common shares | — | — | — |

## MANAGEMENT'S DISCUSSION AND ANALYSIS

Our MD&A, dated March 1, 2006, is incorporated by reference herein and forms an integral part of this Annual Information Form, and should be read in conjunction with our 2005 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, 2005, a total of 457,664,506 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 preferred shares (if any), 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, 2005, 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 than 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 | Price Range ($Cdn) | | Trading Volume |
|---|---|---|---|
| 2005 | High | Low | (000's) |
| January | 42.62 | 38.76 | 37,551 |
| February | 49.43 | 39.85 | 31,452 |
| March | 50.07 | 44.61 | 38,077 |
| April | 51.87 | 44.00 | 37,956 |
| May | 50.13 | 45.40 | 31,963 |
| June | 60.24 | 49.21 | 32,398 |
| July | 63.99 | 57.75 | 30,022 |
| August | 71.40 | 60.79 | 36,670 |
| September | 73.25 | 66.20 | 41,691 |
| October | 71.30 | 57.00 | 46,121 |
| November | 69.10 | 61.28 | 33,462 |
| December | 76.05 | 66.58 | 27,919 |

| New York Stock Exchange | Price Range ($US) | | Trading Volume |
|---|---|---|---|
| 2005 | High | Low | (000's) |
| January | 35.41 | 31.33 | 24,461 |
| February | 40.25 | 32.12 | 27,665 |
| March | 41.70 | 36.62 | 32,158 |
| April | 42.60 | 35.38 | 33,064 |
| May | 40.25 | 35.70 | 24,740 |
| June | 48.95 | 39.45 | 31,440 |
| July | 53.19 | 47.40 | 32,777 |
| August | 59.67 | 49.48 | 53,337 |
| September | 62.50 | 56.43 | 53,100 |
| October | 61.15 | 48.09 | 79,131 |

| | | | |
|---|---|---|---|
| November | 58.47 | 51.15 | 50,831 |
| December | 66.00 | 56.86 | 45,655 |

## 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 1, 2006 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, 2005 and as of the date hereof.



| Name and Municipality of Residence | Office(1) |
|---|---|
| J. KENNETH ALLEY<br>Calgary, Alberta | Senior Vice President and Chief Financial Officer |
| MIKE M. ASHAR<br>Denver, Colorado | Executive Vice President, Refining and Marketing – U.S.A. |
| DAVID W. BYLER<br>Cochrane, Alberta | Executive Vice President, Natural Gas and Renewable Energy |
| RICHARD L. GEORGE<br>Calgary, Alberta | President and Chief Executive Officer |
| TERRENCE J. HOPWOOD<br>Calgary, Alberta | Senior Vice President and General Counsel |
| SUE LEE<br>Calgary, Alberta | Senior Vice President, Human Resources and Communications |
| KEVIN D. NABHOLZ<br>Calgary, Alberta | Executive Vice President, Major Projects |
| THOMAS L. RYLEY<br>Toronto, Ontario | Executive Vice President, Energy, Marketing and Refining – Canada |
| JAY THORNTON<br>Calgary, Alberta | Senior Vice President, Business Integration |
| STEVEN W. WILLIAMS<br>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, Mrs. Lee and Mr. Thornton are Executive Vice-Presidents of Suncor Energy Services Inc., in respect of major projects, human resources and communications, and business services, respectively, which are shared services provided 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 i) Mr. Ford, a director of Suncor who is currently a director of USG Corporation, which is currently in bankruptcy proceedings, and who was also a director of United Airlines (until February 2006) which was in Chapter 11 bankruptcy protection until February and ii) 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 designated professionals of GLJ Petroleum Consultants 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 1, 2006 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.

### Additional Audit Committee Information

Additional information about the members of the Audit Committee and their financial literacy is contained on pages 39-40 inclusive of our

management proxy circular dated March 1, 2006 and incorporated by reference herein. The Audit Committee Charter is attached as Schedule "B" 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, 2005 using constant dollar cost and pricing assumptions as of a point in time, namely December 31, 2005, and the related standardized measure;

- gross and net proved and probable working interest oil reserve quantities relating to surface mineable oil sands operations estimated as at December 31, 2005; and

- gross and net proved and probable working interest oil and gas reserve quantities relating to Firebag in-situ leases, estimated as at December 31, 2005 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 claims were dismissed by the Second Judicial District Court, County of Bernalillio, New Mexico, USA and subsequently appealed by the Plaintiffs in 2005. 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 claims against Suncor and Rick George were dismissed and both Plaintiffs have appealed the dismissals. The appeals are now before the New Mexico Appeals Court and a decision is anticipated in 2006.

## 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 2005 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 judgment 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 _____



**SCHEDULE "B"**

**AUDIT COMMITTEE CHARTER**

**The Audit Committee**

The by-laws of Suncor Energy Inc. provide that the Board of Directors may establish Board committees to whom certain duties may be delegated by the Board. The Board has established, among others, the Audit Committee, and has approved this mandate, which sets out the objectives, functions and responsibilities of the Audit Committee.

**Objectives**

The Audit Committee assists the Board of Directors by:

- monitoring the effectiveness and integrity of the Corporation 's financial reporting systems, management information systems and internal control systems, and by monitoring financial reports and other financial matters.
- selecting, monitoring and reviewing the independence and effectiveness of, and where appropriate replacing, subject to shareholder approval as required by law, external auditors, and ensuring that external auditors are ultimately accountable to the Board of Directors and to

the shareholders of the Corporation.

- Reviewing the effectiveness of the internal auditors; and
- approving on behalf of the Board of Directors certain financial matters as delegated by the Board, include the matters outlined in this mandate.

The Committee does not have decision-making authority, except in the very limited circumstances described herein or where and to the extent that such authority is expressly delegated by the Board of Directors. The Committee conveys its findings and recommendations to the Board of Directors for consideration and, where required, decision by the Board of Directors.

***Constitution***

The Terms of Reference of Suncor's Board of Directors set out requirements for the composition of Board Committees and the qualifications for Committee membership, and specify that the chair and membership of the Committees are determined annually by the Board. As required by Suncor's by-laws, unless otherwise determined by resolution of the board of directors, a majority of the members of a committee constitute a quorum for meetings of committees, and in all other respects, each committee determines its own rules of procedure.

***Functions and Responsibilities***

The Committee has the following functions and responsibilities:

***Internal Controls***

1. Enquire as to the adequacy of the Corporation's system of internal controls, and review the evaluation of internal controls by internal auditors, and the evaluation of financial and internal controls by external auditors.
2. Review management's monitoring of compliance with the Corporation's Code of Business Conduct.
3. Establish procedures for the confidential submission by employees of complaints relating to any concerns with accounting, internal control, auditing or Standards of Business Conduct Code matters, and periodically review a summary of complaints and their related resolution.
4. Review the findings of any significant examination by regulatory agencies concerning the Corporation's financial matters.
5. Periodically review management's governance processes for information technology resources,



to assess their effectiveness in addressing the integrity, the protection and the security of the Corporation's electronic information systems and records.

6. Review the management practices in effect over officers' expenses and perquisites.

***External and Internal Auditors***

7. Evaluate the performance of the external auditors and initiate and approve the engagement or termination of the external auditors, subject to shareholder approval as required by applicable law.
8. Review the audit scope and approach of the external auditors, and approve their terms of engagement and fees.
9. Review any relationships or services that may impact the objectivity and independence of the external auditor, including annual review of the auditor's written statement of all relationships between the auditor (including its affiliates) and the Corporation; review and approve all engagements for non-audit services to be provided by external auditors or their affiliates.
10. Review the external auditor's quality control procedures including any material issues raised by the most recent quality control review or peer review and any issues raised by a government authority or professional authority investigation of the external auditor, providing details on actions taken by the firm to address such issues.
11. Review and approve the appointment or termination of the Director, Internal Audit, and annually review a summary of the remuneration and performance of the Director, Internal Audit.
12. Review the Internal Audit Department Charter, and the plans, activities, organisational structure and qualifications of the internal auditors, and monitor the department's performance and independence.
13. Provide an open avenue of communication between management, the internal auditors or the external auditors, and the Board of Directors.

***Financial Reporting and other Public Disclosure***

14. Review external auditor's management comment letter and management's responses thereto, and enquire as to any disagreements between management and external auditors or restrictions imposed by management on external auditors. Review any unadjusted differences brought to the attention of management by the external auditor and the resolution of same.
15. Review with management and external auditors the financial materials and other disclosure documents referred to in paragraph 16, including any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgements of management that may be material to financial reporting including alternative treatments and their impacts.
16. Review and approve the Corporation's interim consolidated financial statements and accompanying management's discussion and analysis ("MD&A"). Review and make recommendations to the Board of Directors on approval of the Corporation's annual audited financial statements and MD&A, Annual Information Form and Form 40-F. Review other material annual and quarterly disclosure documents or regulatory filings containing or accompanying audited or unaudited financial information.
17. Review and approve the Corporation's policy on external communication and disclosure of material information, including the form and generic content of any quarterly earnings guidance and of any financial disclosure provided to investment analysts and rating agencies.
18. Review any change in the Corporation's accounting policies.
19. Review with legal counsel any legal matters having a significant impact on the financial reports.

***Oil and Gas Reserves***

20. Review with reasonable frequency Suncor's procedures for:
    (A) the disclosure in accordance with applicable law of information with respect to Suncor's oil and gas activities including procedures for complying with applicable disclosure requirements;
    (B) providing information to the qualified reserves evaluators ("Evaluators") engaged annually by Suncor to evaluate Suncor's reserves data for the purpose of public disclosure of such data



in accordance with applicable law.

21. Annually approve the appointment and terms of engagement of the company's Evaluator, including the qualifications and independence of the Evaluator; Review and approve any proposed change in the appointment of the Evaluator, and the reasons for such proposed change including whether there have been disputes between the Evaluator and the Company's management.
22. Annually review Suncor's reserves data and the report of the Evaluator thereon; Annually review and make recommendations to the Board of Directors on the approval of (i) the content and filing by the Company of a statement of reserves data ("Statement") and report of management and the directors thereon to be included in or filed with the Statement, and (ii) the filing of the report of the Evaluator to be included in or filed with the Statement, all in accordance with applicable law.

***Risk Management***

23. Periodically review the policies and practices of the Corporation respecting cash management, financial derivatives, financing, credit, insurance, taxation, commodities trading and related matters. Oversee the Board's risk management governance model by conducting periodic reviews with the objective of appropriately reflecting the principal risks of the Corporation's business in the mandate of the Board and its committees.

***Pension Plan***

24. Review the assets, financial performance, funding status, investment strategy and actuarial reports of the Corporation's pension plan including the terms of engagement of the plan's actuary and fund manager.

***Security***

25. Review on a summary basis any significant physical security management, IT security or business recovery risks and strategies to address such risks.

***Other Matters***

26. Conduct any independent investigations into any matters which come under its scope of responsibilities.
27. Review any recommended appointees to the office of Chief Financial Officer. Review and/or approve other financial matters delegated specifically to it by the Board of Directors.

***Reporting to the Board***

28. Report to the Board of Directors on the activities of the Committee with respect to the foregoing matters as required at each Board meeting and at any other time deemed appropriate by the Committee or upon request of the Board of Directors.

**As adopted by resolution of the Board of Directors.**
Revision Dated January 26, 2006



**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, 2005 using constant dollar cost and pricing assumptions as of a point in time, namely December 31, 2005, 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, 2005; and

(c) proved and probable working interest oil and gas reserve quantities relating to Firebag in-situ leases, estimated as at December 31, 2005 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.

GLJ Petroleum Consultants 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 1, 2006

**GLJ** Petroleum Consultants

Principal Officers:

Harry Jung, P. Eng.
President, C.E.O.
Dana B. Laustsen, P. Eng.
Executive V.P., C.O.O.
Keith M. Braaten, P. Eng.
Executive V.P.

Officers / Vice Presidents:

Terry L. Aarsby, P. Eng.
Jodi L. Anhorn, P. Eng.
Neil I. Dell, P. Eng.
David G. Harris, P. Geol.
Myron J. Hladyshevsky, P. Eng.
Bryan M. Joa, P. Eng.
John H. Stilling, P. Eng.
Douglas R. Sutton, P. Eng.
James H. Willmon, P. Eng.

**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, 2005. 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, 2005 using constant dollar cost and pricing assumptions as of a point in time, namely December 31, 2005, 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, 2005; and proved and probable working interest oil reserves quantities relating to Firebag in-situ leases, estimated as at December 31, 2005 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, 2005:

| | | Standardized Measure of Future Cash Flows for Proved Oil and Gas Reserve Quantities (before income taxes, 10% discount rate) | | |
|---|---|---|---|---|
| **Preparation Date of Report** | **Location of Reserves** | **Evaluated** | **Reviewed** | **Total** |

| | | | | |
|---|---|---|---|---|
| February 21, 2006 | Canada | $ 2,482 million (94%) | $ 166 million (6%) | $ 2,648 million (100%) |

In addition, all proved plus probable company gross and net 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.

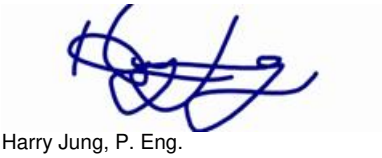
In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, as modified or amended as set out above. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

We have no responsibility to update our reports evaluating reserves data of the Company by us for the year ended December 31, 2005 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:

**GLJ PETROLEUM CONSULTANTS LTD.**



Harry Jung, P. Eng.
President

Calgary, Alberta, Canada
February 24, 2006



## 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 AND INTERNAL CONTROL OVER FINANCIAL REPORTING

See page 38 of Exhibit 99-2.

## AUDIT COMMITTEE FINANCIAL EXPERT

See pages 39 and 40 of Exhibit 99-3.

## CODE OF ETHICS

See page 23 of Exhibit 99-3 and page 47 of our Annual Information Form.

## FEES PAID TO PRINCIPAL ACCOUNTANT

See page 8 of Exhibit 99-3.

## AUDIT COMMITTEE PRE-APPROVAL POLICIES

See page 46 and Schedule A, of Annual Information Form.

## OFF-BALANCE SHEET ARRANGEMENTS

See pages 26 and 27 of Exhibit 99-2.

**TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS**

See page 25 of Exhibit 99-2.

**IDENTIFICATION OF THE AUDIT COMMITTEE**

See page 24 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 10, 2006

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, 2005, including reconciliation to U.S. GAAP (Note 18) |
| 99-2 | Management's Discussion and Analysis for the fiscal year ended December 31, 2005, dated March 1, 2006. |
| 99-3 | Excerpts from pages 8 and 23 through 44 inclusive of Suncor Energy Inc.'s Management Proxy Circular dated March 1, 2006 |
| 99-4 | Consent of PricewaterhouseCoopers LLP |
| 99-5 | Consent of GLJ Petroleum Consultants 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 |

**Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2005, including reconciliation to U.S. GAAP (Note 18)**

## 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 61 to 97 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.

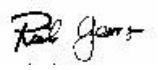
The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. They include certain amounts that are based on estimates and judgments relating to matters not concluded by year-end. Financial information presented elsewhere in this Annual 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 61 to 65. 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.

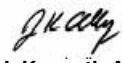
The system of internal controls is further supported by the professional staff of an internal audit function who conduct periodic audits of all aspects of the company's operations.

The company retains independent petroleum consultants, GLJ Petroleum Consultants 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.



**Richard L. George**
President and
Chief Executive Officer



**J. Kenneth Alley**
Senior Vice President and
Chief Financial Officer

*March 1, 2006*



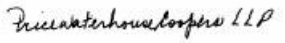
## AUDITORS' REPORT

### TO THE SHAREHOLDERS OF SUNCOR ENERGY INC.

We have audited the Consolidated Balance Sheets of Suncor Energy Inc. (the company) as at December 31, 2005 and 2004 and the Consolidated Statements of Earnings, Cash Flows and Changes in Shareholders' Equity for each of the years in the three year period ended December 31, 2005. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2005, in accordance with Canadian generally accepted accounting principles.



**PricewaterhouseCoopers LLP**
Chartered Accountants
Calgary, Alberta

*March 1, 2006*

**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 March 1, 2006 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors' Report when the change is properly accounted for and adequately disclosed in the financial statements.



**PricewaterhouseCoopers LLP**
Chartered Accountants
Calgary, Alberta

*March 1, 2006*



**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 18.

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. Subsidiaries are defined as entities in which the Company holds a controlling interest, is the general partner or where it is subject to the majority of expected losses or gains.

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 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.

Other specific contractual obligations entered subsequent to January 1, 2005 have been treated as either capital or operating leases as required under Canadian reporting standards.

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 Commerce City 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***

A liability is recognized for future retirement obligations associated with the company's property, plant and equipment. The fair value of the Asset Retirement Obligation (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 and 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 precedes the mining of the related oil sands deposit. 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 note3), 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. See Recently Issued Canadian Accounting Standards, section (l) on page 65, for proposed changes to accounting for overburden.

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 and foreign currency forwards as part of its risk management strategy to manage exposure to interest and foreign exchange 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 11), 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 Statements 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. The expense is based on the fair values of the award at the time of grant and the change in fair value from the time of grant. The expense is recognized in the Consolidated Statements of Earnings over the estimated vesting periods of the respective award.



**(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**

***Non-monetary Transactions***

In 2005, the Canadian Institute of Chartered Accountants (CICA) approved Handbook section 3831 "Non-Monetary Transactions". Effective January 1, 2006, all non-monetary transactions must be measured at fair value (if determinable) unless the transaction lacks commercial substance, or is an exchange of a product held for sale in the ordinary course of business, or is a product to be sold in the same line of business. Commercial substance exists when the company's future cash flows are expected to change significantly as a result of a transaction. The company will be required to record the effects of an existing contract at Oil Sands that exchanges off-gas produced as a by-product of the upgrading operations for natural gas. An equal amount of revenues for the sale of the off-gas, and purchases of crude oil and products for the purchase of the natural gas will be recorded. The amount of the gross-up of revenues and purchases of crude oil and products will be dependent on the prevailing prices for natural gas. Currently the transaction is recorded net in purchases of crude oil and products. Retroactive adjustment is prohibited by the standard.

***Financial Instruments/Other Comprehensive Income/Hedges***

In 2005, the CICA approved Handbook section 3855 “Financial Instruments – Recognition and Measurement”, section 1530 “Comprehensive Income” and section 3865 “Hedges”. Effective January 1, 2007, these standards require the presentation of financial instruments at fair value on the balance sheet.

For specific transactions identified as hedges, changes in fair value are recognized in net earnings or other comprehensive income based on the type and effectiveness of the individual instruments. Upon adoption the company’s presentation will be aligned with the current U.S. GAAP reporting as outlined in note 18 to the consolidated financial statements.

Other comprehensive income will represent the foreign currency translation of self-sustaining subsidiaries, the fair value gains/losses of specific financial investments (available for sale) and the effective portion of gains/losses of cash flow hedges. Presentation of other comprehensive income will require a change in the presentation of the Consolidated Statements of Earnings.

***Overburden Removal Costs***

On February 16, 2006, the Emerging Issues Committee of the CICA approved an abstract regarding the treatment of overburden costs in the mining industry effective July 1, 2006. The proposed abstract would require the capitalization of overburden removal costs when such costs represent betterment to the mine property by facilitating access to reserves in future periods. Costs are to be treated as variable production costs and expensed when no betterment exists. The company currently amortizes the cost of overburden removal using stripping ratios based on a life of mine approach. The company is considering expensing overburden costs incurred on a retroactive basis effective January 1, 2006. With the exception of the impact on 2005 net earnings, the effect of adopting the guidance is not expected to be significant. Net earnings in 2005 would be reduced by approximately $87 million due to increased amounts of overburden moved during the year.



## CONSOLIDATED STATEMENTS OF EARNINGS

| For the years ended December 31 ($ millions) | 2005 | 2004 | 2003 |
|---|---|---|---|
| **Revenues** | | | |
| Operating revenues (notes 6, 16 and 17) | **9 749** | 8 270 | 6 329 |
| Energy marketing and trading activities (note 6c) | **763** | 392 | 276 |
| Net insurance proceeds (note 10d) | **572** | — | — |
| Interest | **2** | 3 | 6 |
| | **11 086** | 8 665 | 6 611 |
| **Expenses** | | | |
| Purchases of crude oil and products | **4 184** | 2 867 | 1 686 |
| Operating, selling and general | **2 130** | 1 769 | 1 478 |
| Energy marketing and trading activities (note 6c) | **746** | 373 | 279 |
| Transportation and other costs | **152** | 132 | 135 |
| Depreciation, depletion and amortization | **720** | 720 | 622 |
| Accretion of asset retirement obligations | **30** | 26 | 25 |
| Exploration (note 17) | **56** | 55 | 51 |
| Royalties (note 4) | **555** | 531 | 139 |
| Taxes other than income taxes (note 17) | **529** | 540 | 466 |
| (Gain) on disposal of assets | **(13)** | (16) | (17) |
| Project start-up costs | **25** | 26 | 16 |
| Financing expenses (income) (note 14) | **(15)** | 24 | (74) |
| | **9 099** | 7 047 | 4 806 |
| **Earnings Before Income Taxes** | **1 987** | 1 618 | 1 805 |
| Provision for income taxes (note 9) | | | |
| Current | **39** | 69 | 38 |
| Future | **703** | 461 | 680 |
| | **742** | 530 | 718 |
| **Net Earnings** | **1 245** | 1 088 | 1 087 |
| | | | |
| **Per Common Share** (dollars) (note 12) | | | |
| Net earnings attributable to common shareholders | | | |
| Basic | **2.73** | 2.40 | 2.42 |
| Diluted | **2.67** | 2.36 | 2.26 |
| Cash dividends | **0.24** | 0.23 | 0.1925 |

See accompanying Summary of Significant Accounting Policies and Notes.



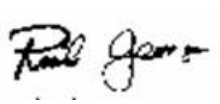
## CONSOLIDATED BALANCE SHEETS

| As at December 31 ($ millions) | 2005 | 2004 |
|---|---|---|
| **Assets** | | |

| | | |
|---|---|---|
| Current assets | | |
| Cash and cash equivalents | **165** | 88 |
| Accounts receivable (notes 10 and 17) | **1 139** | 627 |
| Inventories (note 15) | **523** | 423 |
| Income taxes receivable | **6** | — |
| Future income taxes (note 9) | **83** | 57 |
| Total current assets | **1 916** | 1 195 |
| Property, plant and equipment, net (note 2) | **12 966** | 10 326 |
| Deferred charges and other (note 3) | **469** | 320 |
| Total assets | **15 351** | 11 841 |
| | | |
| **Liabilities and Shareholders' Equity** | | |
| Current liabilities | | |
| Short-term debt | **49** | 30 |
| Accounts payable and accrued liabilities (notes 7 and 8) | **1 830** | 1 306 |
| Income taxes payable | **—** | 32 |
| Taxes other than income taxes | **56** | 41 |
| Total current liabilities | **1 935** | 1 409 |
| Long-term debt (note 5) | **3 007** | 2 217 |
| Accrued liabilities and other (notes 7 and 8) | **1 005** | 749 |
| Future income taxes (note 9) | **3 274** | 2 545 |
| Total liabilities | **9 221** | 6 920 |
| | | |
| Commitments and contingencies (note 10) | | |
| | | |
| Shareholders' equity | | |
| Share capital (note 11) | **732** | 651 |
| Contributed surplus (note 11) | **50** | 32 |
| Cumulative foreign currency translation | **(81)** | (55) |
| Retained earnings | **5 429** | 4 293 |
| Total shareholders' equity | **6 130** | 4 921 |
| Total liabilities and shareholders' equity | **15 351** | 11 841 |

See accompanying Summary of Significant Accounting Policies and Notes.

Approved on behalf of the Board of Directors:



**Richard L. George**
Director



**John T. Ferguson**
Director

*March 1, 2006*



## CONSOLIDATED STATEMENTS OF CASH FLOWS

| For the years ended December 31 ($ millions) | 2005 | 2004 | 2003 |
|---|---|---|---|
| **Operating Activities** | | | |
| Cash flow from operations (a) | **2 476** | 2 013 | 2 040 |
| Decrease (increase) in operating working capital | | | |
| Accounts receivable | **(477)** | (121) | (105) |
| Inventories | **(63)** | (51) | (19) |
| Accounts payable and accrued liabilities | **508** | 337 | 258 |
| Taxes payable | **(23)** | 16 | 5 |
| Cash flow from operating activities | **2 421** | 2 194 | 2 179 |
| **Cash Used in Investing Activities** (a) | **(3 186)** | (1 825) | (1 708) |
| **Net Cash Surplus (Deficiency) Before Financing Activities** | **(765)** | 369 | 471 |
| **Financing Activities** | | | |
| Increase (decrease) in short-term debt | **19** | (1) | 31 |
| Proceeds from issuance of long-term debt | **—** | — | 651 |
| Net increase (decrease) in other long-term debt | **808** | (635) | (716) |
| Issuance of common shares under stock option plans | **69** | 41 | 20 |
| Dividends paid on common shares | **(102)** | (97) | (81) |
| Deferred revenue | **50** | 26 | — |
| Cash flow provided by (used in) financing activities | **844** | (666) | (95) |
| **Increase (Decrease) in Cash and Cash Equivalents** | **79** | (297) | 376 |
| **Effect of Foreign Exchange on Cash and Cash Equivalents** | **(2)** | (3) | (3) |

| | | | |
|---|---|---|---|
| **Cash and Cash Equivalents at Beginning of Year** | **88** | 388 | 15 |
| **Cash and Cash Equivalents at End of Year** | **165** | 88 | 388 |

(a) See Schedules of Segmented Data on pages 72 and 73.

See accompanying Summary of Significant Accounting Policies and Notes.



## CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

| For the years ended December 31 ($ millions) | Share Capital | Contributed Surplus | Cumulative Foreign Currency Translation | Retained Earnings |
|---|---|---|---|---|
| **At December 31, 2002, as previously reported** | 578 | — | — | 2 296 |
| Retroactive adjustment for change in accounting policy, net of tax (note 1) | — | — | — | 12 |
| **At December 31, 2002, as restated** | 578 | — | — | 2 308 |
| Net earnings | — | — | — | 1 087 |
| Dividends paid on common shares | — | — | — | (81) |
| Issued for cash under stock option plans | 20 | — | — | — |
| Issued under dividend reinvestment plan | 6 | — | — | (6) |
| Stock-based compensation expense | — | 7 | — | — |
| Foreign currency translation adjustment | — | — | (26) | — |
| **At December 31, 2003, as restated** | 604 | 7 | (26) | 3 308 |
| Net earnings | — | — | — | 1 088 |
| 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) | — |
| **At December 31, 2004, as restated** | **651** | **32** | **(55)** | **4 293** |
| Net earnings | **—** | **—** | **—** | **1 245** |
| Dividends paid on common shares | **—** | **—** | **—** | **(102)** |
| Issued for cash under stock option plans | **74** | **(5)** | **—** | **—** |
| Issued under dividend reinvestment plan | **7** | **—** | **—** | **(7)** |
| Stock-based compensation expense | **—** | **23** | **—** | **—** |
| Foreign currency translation adjustment | **—** | **—** | **(26)** | **—** |
| **At December 31, 2005** | **732** | **50** | **(81)** | **5 429** |

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) | 2005 | 2004 | 2003 | 2005 | 2004 | 2003 | 2005 | 2004 | 2003 |
| **EARNINGS** | | | | | | | | | |
| **Revenues** (b) | | | | | | | | | |
| Operating revenues | **2 938** | 3 215 | 2 716 | **653** | 499 | 436 | **3 536** | 3 060 | 2 660 |
| Energy marketing and trading activities | **—** | — | — | **—** | — | — | **763** | 400 | 276 |
| Net insurance proceeds (note 10d) | **572** | — | — | **—** | — | — | **—** | — | — |
| Intersegment revenues (c) | **455** | 425 | 385 | **26** | 68 | 76 | **—** | — | — |
| Interest | **—** | — | — | **—** | — | — | **—** | — | — |
| | **3 965** | 3 640 | 3 101 | **679** | 567 | 512 | **4 299** | 3 460 | 2 936 |
| **Expenses** | | | | | | | | | |
| Purchases of crude oil and products | **32** | 75 | 12 | **—** | — | — | **2 585** | 2 115 | 1 797 |
| Operating, selling and general | **1 128** | 939 | 865 | **93** | 100 | 73 | **484** | 418 | 359 |
| Energy marketing and trading activities | **—** | — | — | **—** | — | — | **746** | 381 | 279 |
| Transportation and other costs | **104** | 88 | 101 | **22** | 21 | 24 | **6** | 3 | 3 |
| Depreciation, depletion and amortization | **482** | 505 | 459 | **130** | 115 | 91 | **73** | 69 | 59 |
| Accretion of asset retirement obligations | **24** | 21 | 21 | **5** | 4 | 3 | **1** | 1 | 1 |
| Exploration | **10** | 17 | 11 | **46** | 38 | 40 | **—** | — | — |
| Royalties (note 4) | **406** | 407 | 33 | **149** | 124 | 106 | **—** | — | — |
| Taxes other than income taxes | **51** | 72 | 64 | **3** | 2 | 3 | **338** | 352 | 342 |
| (Gain) loss on disposal of assets | **—** | 4 | (1) | **(12)** | (19) | (12) | **(1)** | (2) | (4) |
| Project start-up costs | **25** | 26 | 10 | **—** | — | — | **—** | — | — |
| Financing expenses (income) | **—** | — | — | **—** | — | — | **—** | — | — |
| | **2 262** | 2 154 | 1 575 | **436** | 385 | 328 | **4 232** | 3 337 | 2 836 |
| **Earnings (loss) before income taxes** | **1 703** | 1 486 | 1 526 | **243** | 182 | 184 | **67** | 123 | 100 |
| Income taxes | **(630)** | (492) | (639) | **(88)** | (67) | (64) | **(26)** | (43) | (47) |
| **Net earnings (loss)** | **1 073** | 994 | 887 | **155** | 115 | 120 | **41** | 80 | 53 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| As at December 31 | | | | | | | | | |
| **TOTAL ASSETS** | **11 850** | 9 067 | 7 970 | **1 307** | 967 | 765 | **1 955** | 1 321 | 1 080 |

(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 2005, 2004 or 2003 consolidated revenues.
(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.



**SCHEDULES OF SEGMENTED DATA** (a) (continued)

| | Refining and Marketing U.S.A. | | | Corporate and Eliminations | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| **For the years ended December 31 ($ millions)** | **2005** | **2004** | **2003** | **2005** | **2004** | **2003** | **2005** | **2004** | **2003** |
| **EARNINGS** | | | | | | | | | |
| **Revenues** (b) | | | | | | | | | |
| Operating revenues | **2 619** | 1 494 | 515 | **3** | 2 | 2 | **9 749** | 8 270 | 6 329 |
| Energy marketing and trading activities | **—** | — | — | **—** | (8) | — | **763** | 392 | 276 |
| Net insurance proceeds (note 10d) | **—** | — | — | **—** | — | — | **572** | — | — |
| Intersegment revenues (c) | **—** | — | — | **(481)** | (493) | (461) | **—** | — | — |
| Interest | **2** | 1 | — | **—** | 2 | 6 | **2** | 3 | 6 |
| | **2 621** | 1 495 | 515 | **(478)** | (497) | (453) | **11 086** | 8 665 | 6 611 |
| **Expenses** | | | | | | | | | |
| Purchases of crude oil and products | **2 048** | 1 171 | 340 | **(481)** | (494) | (463) | **4 184** | 2 867 | 1 686 |
| Operating, selling and general | **167** | 124 | 68 | **258** | 188 | 113 | **2 130** | 1 769 | 1 478 |
| Energy marketing and trading activities | **—** | — | — | **—** | (8) | — | **746** | 373 | 279 |
| Transportation and other costs | **20** | 20 | 7 | **—** | — | — | **152** | 132 | 135 |
| Depreciation, depletion and amortization | **23** | 22 | 6 | **12** | 9 | 7 | **720** | 720 | 622 |
| Accretion of asset retirement obligations | **—** | — | — | **—** | — | — | **30** | 26 | 25 |
| Exploration | **—** | — | — | **—** | — | — | **56** | 55 | 51 |
| Royalties (note 4) | **—** | — | — | **—** | — | — | **555** | 531 | 139 |
| Taxes other than income taxes | **137** | 114 | 57 | **—** | — | — | **529** | 540 | 466 |
| (Gain) loss on disposal of assets | **—** | 1 | — | **—** | — | — | **(13)** | (16) | (17) |
| Project start-up costs | **—** | — | 6 | **—** | — | — | **25** | 26 | 16 |
| Financing expenses (income) | **—** | — | — | **(15)** | 24 | (74) | **(15)** | 24 | (74) |
| | **2 395** | 1 452 | 484 | **(226)** | (281) | (417) | **9 099** | 7 047 | 4 806 |
| **Earnings (loss) before income taxes** | **226** | 43 | 31 | **(252)** | (216) | (36) | **1 987** | 1 618 | 1 805 |
| Income taxes | **(84)** | (9) | (13) | **86** | 81 | 45 | **(742)** | (530) | (718) |
| **Net earnings (loss)** | **142** | 34 | 18 | **(166)** | (135) | 9 | **1 245** | 1 088 | 1 087 |
| As at December 31 | | | | | | | | | |
| **TOTAL ASSETS** | **1 235** | 518 | 442 | **(996)** | (32) | 283 | **15 351** | 11 841 | 10 540 |



**SCHEDULES OF SEGMENTED DATA** (a) (continued)

| | Oil Sands | | | Natural Gas | | | Energy Marketing and Refining – Canada | | |
|---|---|---|---|---|---|---|---|---|---|
| **For the years ended December 31 ($ millions)** | **2005** | **2004** | **2003** | **2005** | **2004** | **2003** | **2005** | **2004** | **2003** |
| **CASH FLOW BEFORE FINANCING ACTIVITIES** | | | | | | | | | |
| **Cash from (used in) operating activities:** | | | | | | | | | |
| Cash flow from (used in) operations | | | | | | | | | |
| Net earnings (loss) | **1 073** | 994 | 887 | **155** | 115 | 120 | **41** | 80 | 53 |
| Exploration expenses | **—** | — | — | **46** | 38 | 40 | **—** | — | — |
| Non-cash items included in earnings | | | | | | | | | |
| Depreciation, depletion and amortization | **482** | 505 | 459 | **130** | 115 | 91 | **73** | 69 | 59 |
| Income taxes | **630** | 492 | 639 | **88** | 67 | 64 | **26** | 43 | 47 |
| (Gain) loss on disposal of assets | **—** | 4 | (1) | **(12)** | (19) | (12) | **(1)** | (2) | (4) |
| Stock-based compensation expense | **—** | — | — | **—** | — | — | **—** | — | — |
| Other | **11** | (29) | 4 | **5** | 4 | (5) | **13** | (3) | 10 |
| Overburden removal outlays | **(287)** | (222) | (175) | **—** | — | — | **—** | — | — |
| Increase (decrease) in deferred credits and other | **(14)** | 8 | (10) | **—** | (1) | — | **—** | 1 | (1) |
| Total cash flow from (used in) operations | **1 895** | 1 752 | 1 803 | **412** | 319 | 298 | **152** | 188 | 164 |
| Decrease (increase) in operating working capital | **(223)** | 72 | 56 | **(5)** | (1) | 12 | **(44)** | 50 | — |
| Total cash from (used in) operating activities | **1 672** | 1 824 | 1 859 | **407** | 318 | 310 | **108** | 238 | 164 |
| **Cash from (used in) investing activities:** | | | | | | | | | |
| Capital and exploration expenditures | **(1 948)** | (1 119) | (953) | **(363)** | (279) | (184) | **(442)** | (228) | (122) |
| Acquisition of Denver refineries and related assets | **—** | — | — | **—** | — | — | **—** | — | — |
| Proceeds from property loss | **44** | — | — | **—** | — | — | **—** | — | — |
| Deferred maintenance shutdown expenditures | **(65)** | (4) | (100) | **(2)** | (1) | — | **—** | (20) | (17) |
| Deferred outlays and other investments | **(1)** | (9) | (10) | **—** | — | — | **3** | (14) | (2) |
| Proceeds from disposals | **41** | 45 | 3 | **21** | 29 | 17 | **3** | 3 | 6 |
| Total cash (used in) investing activities | **(1 929)** | (1 087) | (1 060) | **(344)** | (251) | (167) | **(436)** | (259) | (135) |
| **Net cash surplus (deficiency) before financing activities** | **(257)** | 737 | 799 | **63** | 67 | 143 | **(328)** | (21) | 29 |

(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.

**SCHEDULES OF SEGMENTED DATA** (a) (continued)

| For the years ended December 31 ($ millions) | Refining and Marketing U.S.A. 2005 | 2004 | 2003 | Corporate and Eliminations 2005 | 2004 | 2003 | Total 2005 | 2004 | 2003 |
|---|---|---|---|---|---|---|---|---|---|
| **CASH FLOW BEFORE FINANCING ACTIVITIES** | | | | | | | | | |
| **Cash from (used in) operating activities:** | | | | | | | | | |
| Cash flow from (used in) operations | | | | | | | | | |
| Net earnings (loss) | **142** | 34 | 18 | **(166)** | (135) | 9 | **1 245** | 1 088 | 1 087 |
| Exploration expenses | **—** | — | — | **—** | — | — | **46** | 38 | 40 |
| Non-cash items included in earnings | | | | | | | | | |
| Depreciation, depletion and amortization | **23** | 22 | 6 | **12** | 9 | 7 | **720** | 720 | 622 |
| Income taxes | **84** | 9 | 13 | **(125)** | (150) | (83) | **703** | 461 | 680 |
| (Gain) loss on disposal of assets | **—** | 1 | — | **—** | — | — | **(13)** | (16) | (17) |
| Stock-based compensation expense | **—** | — | — | **23** | 25 | 7 | **23** | 25 | 7 |
| Other | **(2)** | (8) | (2) | **(60)** | (71) | (210) | **(33)** | (107) | (203) |
| Overburden removal outlays | **—** | — | — | **—** | — | — | **(287)** | (222) | (175) |
| Increase (decrease) in deferred credits and other | **—** | 1 | (1) | **86** | 17 | 11 | **72** | 26 | (1) |
| Total cash flow from (used in) operations | **247** | 59 | 34 | **(230)** | (305) | (259) | **2 476** | 2 013 | 2 040 |
| Decrease (increase) in operating working capital | **40** | 68 | 46 | **177** | (8) | 25 | **(55)** | 181 | 139 |
| Total cash from (used in) operating activities | **287** | 127 | 80 | **(53)** | (313) | (234) | **2 421** | 2 194 | 2 179 |
| **Cash from (used in) investing activities:** | | | | | | | | | |
| Capital and exploration expenditures | **(337)** | (190) | (31) | **(63)** | (31) | (32) | **(3 153)** | (1 847) | (1 322) |
| Acquisition of Denver refineries and related assets | **(62)** | — | (272) | **—** | — | — | **(62)** | — | (272) |
| Proceeds from property loss | **—** | — | — | **—** | — | — | **44** | — | — |
| Deferred maintenance shutdown expenditures | **(10)** | (7) | — | **—** | — | — | **(77)** | (32) | (117) |
| Deferred outlays and other investments | **1** | (1) | 3 | **(6)** | 1 | (14) | **(3)** | (23) | (23) |
| Proceeds from disposals | **—** | — | — | **—** | — | — | **65** | 77 | 26 |
| Total cash (used in) investing activities | **(408)** | (198) | (300) | **(69)** | (30) | (46) | **(3 186)** | (1 825) | (1 708) |
| **Net cash surplus (deficiency) before financing activities** | **(121)** | (71) | (220) | **(122)** | (343) | (280) | **(765)** | 369 | 471 |



## NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

### 1. CHANGE IN ACCOUNTING POLICY

#### (a) Preferred Securities

On January 1, 2005, the company retroactively adopted the Canadian accounting standard related to disclosure and presentation of financial instruments. Accordingly, the company's preferred securities, which were redeemed in March 2004, have been reclassified as long-term debt, and the preferred dividend payments have been reclassified to financing expense. The company has restated its property, plant and equipment and depreciation, depletion and amortization to reflect capitalized interest that would have been incurred and amortized had the preferred securities been classified as debt during the period in which they were outstanding. The impact of adopting this accounting standard is as follows:

**Change in Consolidated Balance Sheets**

| ($ millions, increase) | 2005 | 2004 |
|---|---|---|
| Property, plant and equipment | **35** | 37 |
| Total assets | **35** | 37 |
| Future income tax liabilities | **12** | 13 |
| Retained earnings | **23** | 24 |
| Total liabilities and shareholders' equity | **35** | 37 |

**Change in Consolidated Statements of Earnings**

| ($ millions, increase/(decrease)) | 2005 | 2004 | 2003 |
|---|---|---|---|
| Depreciation, depletion and amortization | **2** | 3 | 4 |
| Financing expenses | **—** | 15 | (8) |
| Future income taxes | **(1)** | (6) | (8) |
| Net earnings (loss) | **(1)** | (12) | 12 |
| Per common share – basic (dollars) | **—** | — | — |
| Per common share – diluted (dollars) | **—** | — | — |

#### (b) Consolidation of Variable Interest Entities

On January 1, 2005 the company prospectively adopted Canadian Accounting Guideline 15 – "Consolidation of Variable Interest Entities"(VIEs). Accordingly, the company has consolidated the VIE related to the sale of equipment as described in note 10c. The impact of adopting this standard was an increase to property, plant and equipment of $14 million, an increase to materials and supplies inventory of $8 million and an increase to long-term debt of $22 million. There was no impact to net earnings.

## 2. PROPERTY, PLANT AND EQUIPMENT

| ($ millions) | 2005 Cost | 2005 Accumulated Provision | 2004 Cost | 2004 Accumulated Provision |
|---|---|---|---|---|
| Oil Sands | | | | |
| Plant | **5 644** | **1 107** | 5 197 | 935 |
| Mine and mobile equipment | **1 358** | **561** | 1 313 | 480 |
| In-situ properties | **1 610** | **60** | 1 267 | 26 |
| Pipeline | **107** | **50** | 101 | 48 |
| Capital leases | **39** | **5** | 29 | 25 |
| Major projects in progress | **2 484** | **—** | 1 486 | — |
| Asset retirement cost | **408** | **81** | 325 | 71 |
| | **11 650** | **1 864** | 9 718 | 1 585 |
| Natural Gas | | | | |
| Proved properties | **1 632** | **769** | 1 387 | 652 |
| Unproved properties | **172** | **23** | 125 | 18 |
| Other support facilities and equipment | **53** | **13** | 28 | 14 |
| Asset retirement cost | **14** | **6** | 27 | 3 |
| | **1 871** | **811** | 1 567 | 687 |
| Energy Marketing and Refining – Canada | | | | |
| Refinery | **899** | **481** | 875 | 468 |
| Marketing | **597** | **244** | 525 | 248 |
| Major projects in progress | **464** | **—** | 171 | — |
| Asset retirement cost | **11** | **7** | 11 | 5 |
| | **1 971** | **732** | 1 582 | 721 |
| Refining and Marketing – U.S.A. | | | | |
| Refinery and intangible assets | **244** | **24** | 175 | 11 |
| Marketing | **36** | **3** | 38 | 2 |
| Pipeline | **26** | **2** | 25 | 1 |
| Major projects in progress | **453** | **—** | 128 | — |
| | **759** | **29** | 366 | 14 |
| Corporate | **180** | **29** | 118 | 18 |
| | **16 431** | **3 465** | 13 351 | 3 025 |
| Net property, plant and equipment | | **12 966** | | 10 326 |

## 3. DEFERRED CHARGES AND OTHER

| ($ millions) | 2005 | 2004 |
|---|---|---|
| Oil Sands overburden removal costs (see below) | **202** | 67 |
| Deferred maintenance shutdown costs | **160** | 129 |
| Deferred financing costs | **23** | 25 |
| Other | **84** | 99 |
| Total deferred charges and other | **469** | 320 |
| Oil Sands overburden removal costs | | |
| Balance – beginning of year | **67** | 51 |
| Outlays during the year | **287** | 222 |
| Depreciation on equipment during year | **26** | 19 |
| | **380** | 292 |
| Amortization during year | **(178)** | (225) |
| Balance – end of year | **202** | 67 |



## 4. ROYALTIES

Alberta 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. Firebag is being treated by the Government of Alberta as a separate project from the rest of the Oil Sands operations for royalty purposes. During 2004 and 2005, Firebag was subject to the minimum payment of 1% of R. However, for the rest of Oil Sands, the 2004 calendar year was a transitional year, as the remaining amount of prior years' allowable costs carried forward of approximately $600 million were claimed before the 25% R-C royalty applied to 2004 results.

Royalty expense for the company's Oil Sands operations for the year ended December 31, 2005 was $406 million (2004 – $407 million, 2003 – $33 million).

In July 2004, we issued a statement of claim against the Crown, seeking, among other things, to overturn the government's decision on the

royalty treatment of our Firebag in-situ operations. In February 2006, we advised the Government of Alberta that we had elected not to proceed with our claim relating to the royalty treatment of Firebag.

**5. LONG-TERM DEBT**

**A. Fixed-term debt, redeemable at the option of the company**

| ($ millions) | 2005 | 2004 |
|---|---|---|
| 5.95% Notes, denominated in U.S. dollars, due in 2034 (US$500) | **583** | 602 |
| 7.15% Notes, denominated in U.S. dollars, due in 2032 (US$500) | **583** | 602 |
| 6.70% Series 2 Medium Term Notes, due in 2011 (a) | **500** | 500 |
| 6.80% Medium Term Notes, due in 2007 (a) | **250** | 250 |
| 6.10% Medium Term Notes, due in 2007 (a) | **150** | 150 |
| | **2 066** | 2 104 |
| **Revolving-term debt, with interest at variable rates (see B. Credit Facilities)** | | |
| Commercial paper (interest at December 31, 2005 – 3.2%, 2004 – 2.3%) (b) | **890** | 89 |
| Total unsecured long-term debt | **2 956** | 2 193 |
| Secured long-term debt with interest rates averaging 5.2% (2004 – 5.4%) | **1** | 5 |
| Capital leases (c), (d) | **30** | 19 |
| Variable interest entity long-term debt – see note 1(b) | **20** | — |
| **Total long-term debt** | **3 007** | 2 217 |

(a) The company entered into various interest rate swap transactions in 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 | 2005 Effective Interest Rate | 2004 Effective Interest Rate |
|---|---|---|---|---|
| Swap of 6.70% Medium Term Notes to floating rates | 200 | 2011 | 4.0% | 3.5% |
| Swap of 6.80% Medium Term Notes to floating rates | 250 | 2007 | 4.6% | 4.3% |
| Swap of 6.10% Medium Term Notes to floating rates | 150 | 2007 | 4.0% | 3.6% |

(b) The company is authorized to issue commercial paper to a maximum of $1,200 million having a term not to exceed 364 days. Commercial paper is supported by unutilized credit and term loan facilities (see B. Credit Facilities).

(c) Obligations under capital leases are as follows:

| ($ millions) | 2005 | 2004 |
|---|---|---|
| Equipment leases with interest rates between prime plus 0.5% and 12.4% and maturing on dates ranging from 2008 and 2035 | **30** | 19 |
| | **30** | 19 |



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

| ($ millions) | Capital Leases | Other Long-term Debt |
|---|---|---|
| 2006 | 3 | 910 |
| 2007 | 3 | 401 |
| 2008 | 3 | — |
| 2009 | 3 | — |
| 2010 | 3 | — |
| Later years | 71 | 1 666 |
| Total minimum payments | 86 | 2 977 |
| Less amount representing imputed interest | 56 | |
| Present value of obligation under capital leases | 30 | |

| Long-term Debt (per cent) | 2005 | 2004 |
|---|---|---|
| Variable rate | **50** | 31 |
| Fixed rate | **50** | 69 |

**B. Credit Facilities**

At December 31, 2005, the company had available credit and term loan facilities of $2,330 million, of which $1,255 million was undrawn, as follows:

| ($ millions) | |
|---|---|
| Facility that is fully revolving for 364 days and expires in 2006 | 600 |
| Facility that is fully revolving for 364 days, has a term period of one year and expires in 2007 | 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 | 2 330 |

| | |
|---|---|
| Credit facilities supporting outstanding commercial paper and standby letters of credit | 1 075 |
| Total undrawn credit facilities | 1 255 |

At December 31, 2005, the company had issued $185 million (2004 – $131 million) in letters of credit to various third parties.

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

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

***See next page for more technical details and amounts.***



**(a) Balance Sheet Financial Instruments**

The company's financial instruments recognized in the Consolidated Balance Sheets consist of cash and cash equivalents, accounts receivable, derivative contracts not accounted for as hedges, substantially all current liabilities (except for the current portions of asset retirement and pension 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:

| | 2005 | | 2004 | |
|---|---|---|---|---|
| **($ millions)** | **Carrying Amount** | **Fair Value** | **Carrying Amount** | **Fair Value** |
| Cash and cash equivalents | **165** | **165** | 88 | 88 |
| Accounts receivable | **1 139** | **1 139** | 627 | 627 |
| Current liabilities | **1 826** | **1 826** | 1 252 | 1 252 |
| Long-term debt | | | | |
| Fixed-term | **2 066** | **2 299** | 2 104 | 2 339 |
| Revolving-term | **890** | **890** | 89 | 89 |
| Other | **21** | **21** | 5 | 5 |
| Capital leases | **30** | **30** | 19 | 19 |

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, Cost 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, options and costless collars 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. During 2005, the company resumed its strategic crude oil hedging program, fixing a price or range of prices for a percentage of total production of crude oil for specified periods of time. During 2005, the company entered into agreements covering 7,000 barrels per day

(bpd) beginning January 1, 2006 and ending December 31, 2007. Prices for these barrels are fixed within a range of US$50.00 per barrel to an average of US$92.57 per barrel WTI. The company has not hedged any portion of the foreign exchange component of these forecasted cash flows.

At December 31, 2005, the company had hedged a portion of its forecasted cash flows related to natural gas production and refinery operations, as well as a portion of its euro dollar exposure created by the anticipated purchase of equipment payable in euros in 2006 and 2007.

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 collars, if market rates are not different than, or are within the range of contract prices, the option contracts making up the collar will expire with no exchange of cash. 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:

| Revenue Hedges<br>Strategic Crude Oil | Quantity (bpd) | Average Price (US$ /bbl)(a) | Revenue Hedged (Cdn$ millions)(b) | Hedge Period (c) |
|---|---|---|---|---|
| **As at December 31, 2005** | | | | |
| **Costless collars** | **7 000** | **50.00 – 92.57** | **149 – 276** | **2006** |
| **Costless collars** | **7 000** | **50.00 – 92.57** | **149 – 276** | **2007** |
| As at December 31, 2004 | | | | |
| Crude oil swaps | 36 000 | 23 | 364 | 2005 |
| As at December 31, 2003 | | | | |
| Crude oil swaps | 68 000 | 24 | 772 | 2004 |
| Costless collars | 11 000 | 21 – 24 | 109 – 125 | 2004 |
| Crude oil swaps | 36 000 | 23 | 390 | 2005 |

| Natural Gas | Quantity (GJ/day) | Average Price (Cdn$/GJ) | Revenue Hedged (Cdn$ millions) | Hedge Period (c) |
|---|---|---|---|---|
| **As at December 31, 2005** | | | | |
| **Swaps** | **4 000** | **6.58** | **10** | **2006** |
| **Costless collars** | **25 000** | **10.76 – 16.13** | **24 – 36** | **2006**(g) |
| **Costless collars** | **10 000** | **8.75 – 13.38** | **19 – 29** | **2006**(h) |
| **Swaps** | **4 000** | **6.11** | **9** | **2007** |
| 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(i) |
| As at December 31, 2003 | 30 000 | 6 | 16 | 2004(j) |

| Margin Hedges | Quantity (bpd) | Average Margin US$/bbl | Margin Hedged (Cdn$ millions)(b) | Hedge Period (c) |
|---|---|---|---|---|
| Refined product sale and crude purchase swaps | | | | |
| **As at December 31, 2005** | **5 100** | **11.69** | **10** | **2006**(d) |
| As at December 31, 2004 | 6 300 | 7 | 15 | 2005(e) |
| As at December 31, 2003 | 6 600 | 5 | 3 | 2004(f) |

| Foreign Currency Hedges | Notional (Euro millions) | Average Forward Rate | Dollars Hedged (Cdn$ millions) | Hedge Period |
|---|---|---|---|---|
| **As at December 31, 2005** | | | | |
| Euro/Cdn forward | **9.9** | **1.39** | **13.8** | **2006**(k) |
| Euro/Cdn forwards | **20.6** | **1.41** | **29.0** | **2007**(l) |

(a) Average price for crude oil swaps and costless collars is US$WTI per barrel at Cushing, Oklahoma.
(b) The revenue and margin hedged is translated to Cdn$at the respective year-end exchange rate for convenience purposes.
(c) Original hedge term is for the full year unless otherwise noted.
(d) For the period January to May 2006, inclusive.
(e) For the period January to September 2005, inclusive.
(f) For the period January and February 2004.
(g) For the period January to March 2006, inclusive.
(h) For the period April to October 2006, inclusive.
(i) For the period January to March 2005, inclusive.
(j) For the period January to March 2004, inclusive.
(k) Settlement for applicable forward is March 2006.

(l) Settlements for applicable forwards occurring within the period April to September 2007.



***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, 2005 are detailed in note 5, 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) | 2005 | 2004 |
|---|---|---|
| Revenue hedge swaps and collars | **(4)** | (305) |
| Margin hedge swaps | **1** | 5 |
| Interest rate swaps and foreign currency forwards | **22** | 36 |
| Fair value of outstanding hedging derivative financial instruments | **19** | (264) |

**(c) Energy Marketing and Trading Activities**

In addition to the financial derivatives used for hedging activities, the company uses physical and financial energy contracts, including swaps, forwards and options to gain market information and earn trading and marketing revenues. These energy trading activities are accounted for using the mark-to-market method and as such all financial instruments are recorded at fair value at each balance sheet date. The results of these activities are reported as revenue and as energy trading and marketing expenses in the Consolidated Statements of Earnings.

Physical energy marketing contracts involve activities intended to enhance prices and satisfy physical deliveries to customers. For the year ended December 31, 2005 physical energy marketing contracts resulted in a net pretax gain of $15 million (2004 – pretax gain of $12 million; 2003 – pretax gain of $2 million).

The company also enters into various financial energy contracts for trading activities. The following information presents all positions for the financial instruments only. For the year ended December 31, 2005, a net pretax gain of $5 million (2004 – pretax gain $11 million; 2003 – pretax loss of $3 million) resulted from the settlement and revaluation of the financial energy contracts. The above amounts do not include the impact of related general and administrative costs.

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

| ($ millions) | 2005 | 2004 |
|---|---|---|
| Energy trading assets | **82** | 26 |
| Energy trading liabilities | **70** | 9 |
| Net energy trading assets | **12** | 17 |

**Change in fair value of net assets**

| ($ millions) | 2005 |
|---|---|
| Fair value of contracts at December 31, 2004 | 17 |
| Changes in values attributable to market price and other market changes | **(108)** |
| Fair value of contracts entered into during the period | **115** |
| Fair value of contracts realized during 2005 | **(12)** |
| **Fair value of contracts outstanding at December 31, 2005** | **12** |

The source of the valuations of the above contracts was based on actively quoted prices and/or 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) | 2005 | 2004 |
|---|---|---|

| | | |
|---|---|---|
| Derivative contracts not accounted for as hedges | **82** | 7 |
| Unrecognized derivative contracts accounted for as a hedge | **30** | 21 |
| Total | **112** | 28 |

**7. ACCRUED LIABILITIES AND OTHER**

| ($ millions) | 2005 | 2004 |
|---|---|---|
| Asset retirement obligations **(a)** | **489** | 429 |
| Employee future benefits liability (see note 8) | **190** | 183 |
| Employee and director incentive plans | **110** | 50 |
| Deferred revenue | **140** | 64 |
| Environmental remediation costs **(b)** | **33** | 8 |
| Other | **43** | 15 |
| Total | **1 005** | 749 |

**(a) Asset Retirement Obligations**

The asset retirement obligation (ARO) also includes $54 million in current liabilities (2004 – $47 million). The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the total obligations associated with the retirement of property, plant and equipment.

| ($ millions) | 2005 | 2004 |
|---|---|---|
| Asset retirement obligations, beginning of year | **476** | 401 |
| Liabilities incurred | **71** | 82 |
| Liabilities settled | **(34)** | (33) |
| Accretion of asset retirement obligations | **30** | 26 |
| Asset retirement obligations, end of year | **543** | 476 |

The total undiscounted amount of estimated cash flows required to settle the obligations at December 31, 2005 was approximately $1.2 billion (2004 – $1.1 billion). The liability recognized in 2005 has been discounted using a credit-adjusted risk-free rate of 5.6% (2004 – 6.0%). 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 include an additional $14 million in current liabilities (2004 – $35 million). Environmental remediation costs include obligations assumed through the purchase of the Commerce City refineries. There is no associated asset retirement obligation for these assets as the assets have an indeterminate life.



**8. 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, 2005 was $889 million.*

*As required by government regulations, Suncor sets aside funds with an independent trustee to meet certain of these obligations. In addition, commencing in 2005, the company began to fund its unregistered supplementary pension plan and senior executive retirement plan on a voluntary basis. The amount and timing of future funding for these supplementary plans is subject to capital availability and is at the company's discretion. At the end of December 2005,* ***Plan Assets*** *to meet the* ***Benefit Obligation*** *were $479 million.*

*The excess of the* ***Benefit Obligation*** *over* ***Plan Assets*** *of $410 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 unregistered supplementary pensions and senior executive retirement plans that, commencing in 2005, are voluntarily funded through retirement compensation arrangements, and/or paid directly to recipients. Company contributions to the funded plans are deposited with independent trustees who act as custodians of the 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 plan 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:

| ($ millions) | Pension Benefits 2005 | Pension Benefits 2004 | Other Post-retirement Benefits 2005 | Other Post-retirement Benefits 2004 |
|---|---|---|---|---|
| **Change in benefit obligation** | | | | |
| Benefit obligation at beginning of year | **624** | 568 | **128** | 117 |
| Service costs | **32** | 25 | **5** | 5 |
| Interest costs | **38** | 34 | **6** | 7 |
| Plan participants' contributions | **3** | 3 | **—** | — |
| Acquisition (a) | **1** | — | **1** | — |
| Foreign exchange | **—** | (2) | **—** | (1) |
| Actuarial loss | **75** | 21 | **8** | 4 |
| Benefits paid | **(28)** | (25) | **(4)** | (4) |
| Benefit obligation at end of year (b), (e) | **745** | 624 | **144** | 128 |
| **Change in plan assets (c)** | | | | |
| Fair value of plan assets at beginning of year | **399** | 336 | **—** | — |
| Actual return on plan assets | **41** | 33 | **—** | — |
| Employer contributions | **61** | 49 | **—** | — |
| Plan participants' contributions | **3** | 3 | **—** | — |
| Benefits paid | **(25)** | (22) | **—** | — |
| Fair value of plan assets at end of year (e) | **479** | 399 | **—** | — |
| Net unfunded obligation | **(266)** | (225) | **(144)** | (128) |
| Items not yet recognized in earnings: | | | | |
| Unamortized net actuarial loss (d) | **167** | 125 | **53** | 49 |
| Unamortized past service costs | **—** | — | **(26)** | (29) |
| Accrued benefit liability | **(99)** | (100) | **(117)** | (108) |
| Current liability | **(37)** | (40) | **(3)** | (3) |
| Long-term liability | **(76)** | (78) | **(114)** | (105) |
| Long-term asset | **14** | 18 | **—** | — |
| Total accrued benefit liability | **(99)** | (100) | **(117)** | (108) |

(a) In 2005, in connection with the acquisition of the Colorado Refining Company, the company assumed pension obligations of $1 million and other post-retirement benefit obligations of $1 million. No pension plan assets were acquired.

(b) Obligations are based on the following assumptions:

| (per cent) | Pension Benefit Obligations 2005 | Pension Benefit Obligations 2004 | Other Post-retirement Benefits Obligation 2005 | Other Post-retirement Benefits Obligation 2004 |
|---|---|---|---|---|
| Discount rate | **5.00** | 5.75 | **5.00** | 5.75 |
| Rate of compensation increase | **4.50** | 4.50 | **4.25** | 4.25 |

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

| ($ millions) | Rate of Return on Plan Assets 1% increase | Rate of Return on Plan Assets 1% decrease | Discount Rate 1% increase | Discount Rate 1% decrease | Rate of Compensation Increase 1% increase | Rate of Compensation Increase 1% decrease |
|---|---|---|---|---|---|---|
| Increase (decrease) to net periodic benefit cost | (4) | 4 | (15) | 17 | 7 | (7) |
| Increase (decrease) to benefit obligation | — | — | (119) | 140 | 35 | (33) |

In order to measure the expected cost of other post-retirement benefits, a 10% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2005 (2004 – 11.5%; 2003 – 12%). It is assumed that this rate will decrease by 0.5% annually, to 5% by 2015, 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 | 1 | (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 11 years for pension benefits (2004 and 2003 – 12 years), and over the expected average future service life to full eligibility age of 9 years for other post-retirement benefits (2004 and 2003 – 12 years).
(e) 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 partially funded and unfunded plans, as follows:

| | Pension Benefits | | Other Post-retirement Benefits | |
|---|---|---|---|---|
| ($ millions) | 2005 | 2004 | 2005 | 2004 |
| Partially funded plans | **745** | 537 | **—** | — |
| Unfunded plans | — | 87 | **144** | 128 |
| Benefit obligation at end of year | **745** | 624 | **144** | 128 |

**Components of Net Periodic Benefit Cost** (a)

| | Pension Benefits | | | Other Post-retirement Benefits | | |
|---|---|---|---|---|---|---|
| ($ millions) | 2005 | 2004 | 2003 | 2005 | 2004 | 2003 |
| Current service costs | **32** | 25 | 18 | **5** | 5 | 3 |
| Interest costs | **38** | 34 | 32 | **6** | 7 | 6 |
| Expected return on plan assets (b) | **(28)** | (25) | (20) | **—** | — | — |
| Amortization of net actuarial loss | **21** | 19 | 22 | **1** | 1 | 1 |
| Net periodic benefit cost recognized (c) | **63** | 53 | 52 | **12** | 13 | 10 |

**Components of Net Incurred Benefit Cost** (a)

| | Pension Benefits | | | Other Post-retirement Benefits | | |
|---|---|---|---|---|---|---|
| ($ millions) | 2005 | 2004 | 2003 | 2005 | 2004 | 2003 |
| Current service costs | **32** | 25 | 18 | **5** | 5 | 3 |
| Interest costs | **38** | 34 | 32 | **6** | 7 | 6 |
| Actual (return) loss on plan assets (b) | **(41)** | (33) | (45) | **—** | — | — |
| Actuarial (gain) loss | **75** | 21 | 37 | **8** | 4 | 8 |
| Net incurred benefit cost | **104** | 47 | 42 | **19** | 16 | 17 |

(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 11 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) | 2005 | 2004 | 2003 | 2005 | 2004 | 2003 |
| Discount rate | **5.75** | 6.00 | 6.50 | **5.75** | 6.00 | 6.50 |
| Expected return on plan assets | **6.75** | 7.00 | 7.25 | **—** | — | — |
| Rate of compensation increase | **4.50** | 4.00 | 4.00 | **4.25** | 4.00 | 4.00 |



**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 restricted to those permitted by legislation, where applicable. Investments are made through pooled, mutual, segregated or exchange traded funds.

The company's weighted average pension plan asset allocation based on market values as at December 31, 2005 and 2004, and the target allocation for 2006 are as follows:

| | Target Allocation % | Percentage of Plan Assets | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Asset Category | | | |
| Equities | 60 | **60** | 60 |
| Fixed income | 40 | **40** | 40 |
| 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 2006 will be $64 million, including approximately $12 million for the company's senior executive and supplemental retirement plans. Expected benefit payments from all of our plans are as follows:

| | Pension Benefits | Other Post-retirement Benefits |
|---|---|---|
| 2006 | 29 | 4 |
| 2007 | 31 | 5 |
| 2008 | 33 | 5 |
| 2009 | 35 | 6 |
| 2010 | 37 | 6 |
| 2011 – 2015 | 227 | 39 |
| Total | 392 | 65 |

**Defined Contribution Pension Plan**
The company has a Canadian defined contribution plan and two U.S. 401(k) savings plans, under which both the company and employees make contributions. Company contributions and corresponding expense totalled $10 million in 2005 (2004 – $8 million; 2003 – $6 million).

**9. 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:

| | 2005 | | 2004 | | 2003 | |
|---|---|---|---|---|---|---|
| ($ millions) | Amount | % | Amount | % | Amount | % |
| Federal tax rate | **696** | **35** | 582 | 36 | 668 | 37 |
| Provincial abatement | **(199)** | **(10)** | (162) | (10) | (181) | (10) |
| Federal surtax | **22** | **1** | 18 | 1 | 20 | 1 |
| Provincial tax rates | **229** | **12** | 190 | 12 | 226 | 13 |
| **Statutory tax and rate** | **748** | **38** | 628 | 39 | 733 | 41 |
| Adjustment of statutory rate for future rate reductions | **(88)** | **(5)** | (86) | (5) | (100) | (6) |
| | **660** | **33** | 542 | 34 | 633 | 35 |
| Add (deduct) the tax effect of: | | | | | | |
| Crown royalties | **119** | **6** | 133 | 8 | 50 | 3 |
| Resource allowance (a) | **(48)** | **(2)** | (69) | (4) | (31) | (2) |
| Large corporations tax | **23** | **1** | 18 | 1 | 19 | 1 |
| Tax rate changes on opening future income taxes (b) | **—** | **—** | (53) | (3) | 89 | 5 |
| Attributed Canadian royalty income | **(24)** | **(1)** | (29) | (2) | (8) | — |
| Stock-based compensation | **8** | **—** | 8 | — | 3 | — |
| Assessments and adjustments | **7** | **—** | — | — | — | — |
| Capital gains | **(6)** | **—** | (18) | (1) | (34) | (2) |
| Other | **3** | **—** | (2) | — | (3) | — |
| **Income taxes and effective rate** | **742** | **37** | 530 | 33 | 718 | 40 |

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

(b) 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 2005 and 2004, 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.

In 2005 net income tax payments totalled $77 million (2004 – $50 million payment; 2003 – $45 million payment).

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 – an increase of $89 million).

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

| | 2005 | | 2004 | |
|---|---|---|---|---|
| **($ millions)** | **Current** | **Non-current** | **Current** | **Non-current** |
| Future income tax assets: | | | | |
| Employee future benefits | **7** | **—** | 14 | — |
| Asset retirement obligations | **19** | **—** | 16 | — |
| Inventories | **67** | **—** | 27 | — |
| Other | **(10)** | **—** | — | — |
| | **83** | **—** | 57 | — |
| Future income tax liabilities: | | | | |
| Depreciation | **—** | **3 294** | — | 2 747 |
| Overburden removal costs | **—** | **68** | — | 20 |
| Deferred maintenance shutdown costs | **—** | **51** | — | 44 |
| Reorganization adjustment | **—** | **197** | — | — |
| Employee future benefits | **—** | **(87)** | — | (77) |
| Asset retirement obligations | **—** | **(162)** | — | (139) |
| Attributed Canadian royalty income | **—** | **(86)** | — | (69) |
| Other | **—** | **(1)** | — | 19 |
| | **—** | **3 274** | — | 2 545 |



## 10. COMMITMENTS, CONTINGENCIES, VARIABLE INTEREST ENTITIES, 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, 2005, future minimum amounts payable under these leases and agreements are as follows:

| **($ millions)** | **Pipeline Capacity and Energy Services (1)** | **Operating Leases** |
|---|---|---|
| 2006 | 222 | 36 |
| 2007 | 216 | 32 |
| 2008 | 232 | 27 |
| 2009 | 242 | 22 |
| 2010 | 245 | 20 |
| Later years | 4 018 | 96 |
| | 5 175 | 233 |

(1) Includes annual tolls payable under transportation service agreements with major pipeline companies to use a portion of their pipeline capacity and tankage, as applicable, including the shipment of crude oil from Fort McMurray to Hardisty, Alberta. The agreements commenced in 1999 and extend up to 2033. As the initial shipper on one of the pipelines, Suncor's tolls payable are subject to annual adjustments.

Suncor has commitments under long-term energy agreements to obtain a portion of the power and the steam generated by certain cogeneration facilities owned by a major third party energy company. Since October 1999, this third party has also managed the operations of Suncor's existing energy services facility at its Oil Sands operations.

### (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. Estimates of retirement obligation costs can change significantly based on such factors as operating experience and changes in legislation and regulations.

The company carries both primary and excess 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. The excess coverage of US$700 million can be used for either property loss or business interruption coverage for its oil sands operations. 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. Effective January 1, 2006, the excess coverage has a ceiling of US$40 WTI for the purposes of determining the loss for business interruption claims.

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 flow 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, Guarantees and Off-balance Sheet Arrangements**
At December 31, 2005, the company had various off-balance sheet arrangements with Variable Interest Entities (VIEs) and indemnification agreements with third parties as described below.

The company has a securitization program in place to sell, on a revolving, fully serviced and limited recourse basis, up to $340 million of accounts receivable (2004 – $170 million) 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, 2005, $340 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 $58 million in 2005. A liability has not been recorded for this indemnification as the company believes it has no significant exposure to credit losses. Proceeds received from new securitizations and proceeds from collections reinvested in securitizations on a revolving basis for the year ended December 31, 2005, were $170 million and approximately $2,220 million, respectively. The company recorded an after-tax loss of approximately $4 million on the securitization program in 2005 (2004 – $2 million; 2003 – $3 million).



In 1999, the company entered into an equipment sale and leaseback arrangement with a VIE for proceeds of $30 million. The VIE's sole asset is the equipment sold to it and leased back by the company. As described in note 1, the VIE was consolidated effective January 1, 2005. The initial lease term covers a period of seven years and is accounted for as an operating lease. The company has provided a residual value guarantee on the equipment of up to $7 million should it elect not to repurchase the equipment at the end of the lease term. Had the company elected to terminate the lease at December 31, 2005, the total cost would have been $21 million (2004 – $25 million). Annualized equipment lease payments in 2005 were $5 million (2004 – $6 million; 2003 – $4 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 5) 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**
In January and February 2006, the company received an additional $175 million in proceeds related to its business interruption insurance coverage. The proceeds related to business activity during 2005 and have accordingly been recognized as revenue in the fourth quarter of 2005. This brings total proceeds from our business interruption claim to US$500 million out of the US$900 million available. The company is currently negotiating a final settlement with its business interruption insurers. Any subsequent proceeds will be recorded when unconditionally received or receivable.

**11. SHARE CAPITAL**

**(a) Authorized:**
***Common Shares***
The company is authorized to issue an unlimited number of common shares without nominal or par value.

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

**(b) Issued:**

| | 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 |
| Issued for cash under stock option plans | **3 302** | **74** |
| Issued under dividend reinvestment plan | **122** | **7** |
| **Balance as at December 31, 2005** | **457 665** | **732** |

***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 next page for more technical details and amounts on the company's stock option plans.***



**(i) EXECUTIVE STOCK PLAN** Under this plan, the company granted 518,000 common share options in 2005 (2004 – 1,346,000; 2003 – 1,902,000) 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 2005, the company granted 1,253,000 options (2004 –1,742,000; 2003 – 1,305,000) 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.

On January 31, 2005, in connection with the achievement of a predetermined performance criterion, 2,062,000 SunShare options vested, representing approximately 25% of the then outstanding unvested options under the SunShare plan. On June 30, 2005, an additional predetermined performance criterion under the SunShare plan was met, resulting in the vesting of 50% of the outstanding, unvested SunShare options on April 30, 2008. As the company had been accruing costs of these options, the impact on net earnings for 2005 was not significant. The remaining 50% of the outstanding, unvested SunShare options may vest on April 30, 2008 if the final predetermined performance criterion is met. If the performance criteria is not met, the unvested options that have not previously expired or been cancelled, will automatically vest on January 1, 2012.

**(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 non-insider senior managers and key employees. Under this plan, the company granted 901,000 common share options in 2005 (2004 – nil, 2003 – nil) to senior managers and key employees. 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.

**(iv) DEFERRED SHARE UNITS (DSUs)** The company had 1,190,000 DSUs outstanding at December 31, 2005 (1,228,000 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 2005, 81,000 DSUs were redeemed for cash consideration of $5 million (2004 – no redemption, 2003 – 185,000 redeemed for cash consideration of $5 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, 2005, the total liability related to the DSUs was $87 million, of which $4 million was classified as current (see note 7).

During 2005, total pretax compensation expense related to deferred share units was $39 million (2004 – $12 million; 2003 – $8 million).

**(v) PERFORMANCE SHARE UNITS (PSUs)** During 2005, the company issued 453,000 PSUs (2004 – 354,000; 2003 – 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 factor). 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 anticipated performance factor. This expense is recognized on a straight-line basis over the term of the grant. Pretax expense recognized for PSUs during 2005 was $21 million (2004 – $5 million; 2003 – $nil).



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

| | Number (thousands) | Range of Exercise Prices Per Share ($) | Weighted-average Exercise Price Per Share ($) |
|---|---|---|---|
| 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 |
| Granted | **2 672** | **36.93 – 71.13** | **48.27** |
| Exercised | **(3 302)** | **5.22 – 41.38** | **20.71** |
| Cancelled | **(854)** | **26.14 – 70.53** | **30.82** |
| **Outstanding, December 31, 2005** | **19 203** | **5.22 – 71.13** | **28.12** |
| **Exercisable, December 31, 2005** | **9 361** | **5.28 – 42.65** | **21.77** |

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) | 2005 | 2004 | 2003 |
|---|---|---|---|
| | **10 724** | 4 342 | 6 893 |

The following table is an analysis of outstanding and exercisable common share options as at December 31, 2005:

| | Outstanding | | | Exercisable | |
|---|---|---|---|---|---|
| Exercise Prices ($ ) | Number (thousands) | Weighted-average Remaining Contractual Life | Weighted-average Exercise Price Per Share ($) | Number (thousands) | Weighted-average Exercise Price Per Share ($) |
| 5.28 – 10.13 | 912 | 3 | 9.51 | 912 | 9.51 |
| 12.28 – 21.35 | 3 074 | 4 | 15.38 | 3 074 | 15.38 |
| 23.65 – 31.45 | 10 586 | 6 | 27.12 | 4 753 | 26.51 |
| 32.22 – 43.45 | 3 505 | 8 | 37.79 | 622 | 35.20 |
| 45.51 – 71.13 | 1 126 | 7 | 57.26 | — | — |
| Total | 19 203 | 6 | 28.12 | 9 361 | 21.77 |

**(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:

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| Annual dividend per share | **$ 0.24** | $ 0.23 | $ 0.1925 |
| Risk-free interest rate | **3.69%** | 3.79% | 4.39% |
| Expected life | **6 years** | 6 years | 7 years |
| Expected volatility | **28%** | 29% | 32% |
| Weighted-average fair value per option | **$ 15.42** | $ 12.02 | $ 9.94 |



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) | 2005 | 2004 | 2003 |
|---|---|---|---|
| Net earnings attributable to common shareholders – as reported | **1 245** | 1 088 | 1 087 |
| Less: compensation cost under the fair value method for pre-2003 options | **13** | 47 | 30 |
| Pro forma net earnings attributable to common shareholders for pre-2003 options | **1 232** | 1 041 | 1 057 |
| Basic earnings per share | | | |
| As reported | **2.73** | 2.40 | 2.42 |
| Pro forma | **2.70** | 2.30 | 2.35 |
| Diluted earnings per share | | | |
| As reported | **2.67** | 2.36 | 2.26 |
| Pro forma | **2.64** | 2.26 | 2.20 |

**12. EARNINGS PER COMMON SHARE**

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

| ($ millions) | 2005 | 2004 | 2003 |
|---|---|---|---|

| | | | |
|---|---|---|---|
| Net earnings attributable to common shareholders | **1 245** | 1 088 | 1 087 |
| | | | |
| (millions of common shares) | | | |
| Weighted-average number of common shares | **456** | 453 | 450 |
| Dilutive securities: | | | |
| Options issued under stock-based compensation plans | **10** | 9 | 8 |
| Redemption of preferred securities by the issuance of common shares | **—** | — | 22 |
| Weighted-average number of diluted common shares | **466** | 462 | 480 |
| | | | |
| (dollars per common share) | | | |
| Basic earnings per share (a) | **2.73** | 2.40 | 2.42 |
| Diluted earnings per share (b) | **2.67** | 2.36 | 2.26 |

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

**13. ACQUISITION OF REFINERY AND RELATED ASSETS**

On May 31, 2005, the company acquired all of the issued shares of the Colorado Refining Company, an indirect wholly-owned subsidiary of Valero Energy Corp. for cash consideration of $37 million. Additional payments for working capital and associated inventory brought the total purchase price to $62 million. The acquired company's principal assets are a Commerce City refinery and a products terminal located in Grand Junction, Colorado. The allocation of fair value to the assets acquired and liabilities assumed was $79 million for property, plant and equipment, $30 million for inventory and $41 million for environmental liabilities assumed. The fair value assigned to other liabilities was $6 million. The acquisition was accounted for by the purchase method of accounting.

The results of operations for these assets have been included in the consolidated financial statements from the date of acquisition. The new operations have been reported as part of the Refining and Marketing – U.S.A. segment in the Schedules of Segmented Data.



**14. FINANCING EXPENSES (INCOME)**

| **($ millions)** | **2005** | **2004** | **2003** |
|---|---|---|---|
| Interest on debt | **151** | 157 | 185 |
| Capitalized interest | **(119)** | (62) | (63) |
| Net interest expense | **32** | 95 | 122 |
| Foreign exchange (gain) on long-term debt | **(37)** | (82) | (213) |
| Other foreign exchange (gain) loss | **(10)** | 11 | 17 |
| Total financing expenses (income) | **(15)** | 24 | (74) |

Cash interest payments in 2005 totalled $149 million (2004 – $152 million; 2003 – $184 million).

**15. INVENTORIES**

| **($ millions)** | **2005** | **2004** |
|---|---|---|
| Crude oil | **279** | 194 |
| Refined products | **124** | 120 |
| Materials, supplies and merchandise | **120** | 109 |
| Total | **523** | 423 |

The replacement cost of crude oil and refined product inventories exceeded their LIFO carrying value by $202 million (2004 – $65 million) as at December 31, 2005.

During 2005, the company recorded a pretax gain of $16 million related to a permanent reduction in LIFO inventory layers (2004 – $8 million pretax gain).

**16. 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)** | **2005** | **2004** | **2003** |
|---|---|---|---|
| Operating revenues | | | |
| Sales to Energy Marketing and Refining – Canada segment joint ventures: | | | |
| Refined products | **327** | 320 | 301 |
| Petrochemicals | **279** | 272 | 187 |

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, 2005, amounts due from Energy Marketing and Refining – Canada segment joint ventures were $22 million (2004 – $17 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.



## 17. SUPPLEMENTAL INFORMATION

| ($ millions) | 2005 | 2004 | 2003 |
|---|---|---|---|
| Export sales (a) | **648** | 693 | 549 |
| Exploration expenses | | | |
| Geological and geophysical | **22** | 33 | 18 |
| Other | **1** | 1 | 1 |
| Cash costs | **23** | 34 | 19 |
| Dry hole costs | **33** | 21 | 32 |
| Cash and dry hole costs (b) | **56** | 55 | 51 |
| Leasehold impairment (c) | **13** | 8 | 16 |
| | **69** | 63 | 67 |
| Taxes other than income taxes | | | |
| Excise taxes (d) | **482** | 496 | 428 |
| Production, property and other taxes | **47** | 44 | 38 |
| | **529** | 540 | 466 |
| Allowance for doubtful accounts | **4** | 3 | |

(a) Sales of crude oil, natural gas and refined products from Canada 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.

## 18. 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 | 2005 | 2004 | 2003 |
|---|---|---|---|---|
| Net earnings as reported, Canadian GAAP | | **1 245** | 1 088 | 1 087 |
| Adjustments | | | | |
| Derivatives and hedging activities | (a) | **83** | 92 | (176) |
| Stock-based compensation | (b) | **(26)** | (10) | (2) |
| Asset retirement obligations | (c) | **—** | — | 7 |
| Income tax expense | | **(28)** | (27) | 54 |
| Net earnings from continuing operations, U.S. GAAP | | **1 274** | 1 143 | 970 |
| Cumulative effect of change in accounting principles, net of income taxes of $nil (2004 – $nil; 2003 – $23) | (c) | **—** | — | (66) |
| Net earnings, U.S. GAAP | | **1 274** | 1 143 | 904 |
| Derivatives and hedging activities, net of income taxes of $70 (2004 – $35; 2003 – $7) | (a) | **140** | (67) | 18 |
| Minimum pension liability, net of income taxes of $8 (2004 – $3; 2003 – $nil) | (d) | **(15)** | 5 | 7 |
| Foreign currency translation adjustment | (e) | **(26)** | (29) | (26) |
| Comprehensive income, U.S. GAAP | | **1 373** | 1 052 | 903 |

| per common share (dollars) | 2005 | 2004 | 2003 |
|---|---|---|---|
| Net earnings per share from continuing operations, U.S. GAAP | | | |
| Basic | **2.79** | 2.52 | 2.16 |
| Diluted | **2.73** | 2.47 | 2.02 |
| Net earnings per share, U.S. GAAP | | | |
| Basic | **2.79** | 2.52 | 2.01 |
| Diluted | **2.73** | 2.47 | 1.88 |

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

| | Notes | December 31, 2005 As Reported | December 31, 2005 U.S. GAAP | December 31, 2004 As Reported | December 31, 2004 U.S. GAAP |
|---|---|---|---|---|---|
| Current assets | (a,f) | **1 916** | **1 916** | 1 195 | 1 300 |
| Property, plant and equipment, net | (f) | **12 966** | **12 966** | 10 326 | 10 340 |
| Deferred charges and other | (a,d) | **469** | **500** | 320 | 367 |
| Total assets | | **15 351** | **15 382** | 11 841 | 12 007 |
| Current liabilities | (a) | **1 935** | **1 935** | 1 409 | 1 701 |
| Long-term borrowings | (a,f) | **3 007** | **3 029** | 2 217 | 2 275 |
| Accrued liabilities and other | (d) | **1 005** | **1 092** | 749 | 815 |
| Future income taxes | (a,d) | **3 274** | **3 247** | 2 545 | 2 526 |
| Share capital | (b) | **732** | **780** | 651 | 699 |
| Contributed surplus | (b) | **50** | **88** | 32 | 44 |
| Cumulative foreign currency translation | (e) | **(81)** | **—** | (55) | — |
| Retained earnings | | **5 429** | **5 341** | 4 293 | 4 176 |
| Accumulated other comprehensive income | (a,d,e) | **—** | **(130)** | — | (229) |
| Total liabilities and shareholders' equity | | **15 351** | **15 382** | 11 841 | 12 007 |

**(a) Derivative Financial Instruments**

The company accounts for its derivative financial instruments under Canadian GAAP as described in note 6. 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 6, 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, 2005 the company had hedged a portion of its forecasted Canadian dollar denominated cash flows subject to U.S. dollar WTI commodity price risk for 2006 and 2007. The company has 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.

During 2005, the company recognized $2 million of hedging losses that, under U.S. GAAP, would have been recognized as hedge ineffectiveness losses in prior periods. Under U.S. GAAP, for the year ended December 31, 2005, the company would have recognized $2 million of hedge ineffectiveness relating to forecasted cash flows in 2006 and 2007 primarily due to foreign exchange fluctuations during the period (2004 – $57 million ineffectiveness relating to 2005 forecasted cash flows). The net earnings impact of this ineffectiveness will not be recognized for Canadian GAAP purposes until the related forecasted crude oil sales occur.



***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, 2005, the company had interest rate derivatives classified as fair value hedges outstanding for up to six 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 recognized as additional crude oil revenues during 2004. For U.S. GAAP purposes, the company recognized the $28 million pretax 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. The inventory was repurchased in 2004.

***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) | 2005 | 2004 |
|---|---|---|
| OCI attributable to derivatives and hedging activities, beginning of the period, net of income taxes of $69 (2004 – $34) | **(138)** | (71) |
| Current period net changes arising from cash flow hedges, net of income taxes of $2 (2004 – $61) | **(3)** | (122) |
| Net hedging losses at the beginning of the period reclassified to earnings during the period, net of income taxes of $72 (2004 – $26) | **143** | 55 |
| OCI attributable to derivatives and hedging activities, end of period, net of income taxes of $1 (2004 – $69) | **2** | (138) |

For the year ended December 31, 2005, assets increased by $22 million and liabilities increased by $22 million as a result of recording all derivative instruments at fair value in accordance with U.S. GAAP.

The earnings loss associated with realized and unrealized hedge ineffectiveness on derivative contracts designated as cash flow hedges during the period was $3 million, net of income taxes of $2 million (2004 – loss of $130 million, net of income taxes of $66 million; 2003 – loss of $199 million, net of income taxes of $93 million). The company estimates that $4 million of after-tax hedging gains 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, 2005 U.S. GAAP net earnings increased by $55 million, net of income taxes of $28 million (2004 – increased net earnings of $65 million, net of income taxes of $27 million; 2003 – decreased net earnings of $120 million, net of income taxes of $56 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 is 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, 2005, U.S. GAAP net earnings would have been reduced by $26 million (2004 – $10 million; 2003 – $2 million) to reflect additional stock-based compensation expense.

Under Canadian GAAP, 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, 2005 would have been reduced by $4million (2004 – $37 million; 2003 – $27 million) and $0.01 per share (2004 – $0.08; 2003 – $0.06), respectively.

**(c) Asset Retirement Obligations**

Under Canadian GAAP, the company retroactively adopted Canadian accounting standards related to asset retirement obligations on January 1, 2004, with restatements of all prior period comparative amounts. Under U.S. GAAP the company would have adopted asset retirement obligations 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 (net of future income taxes of $21 million).

**(d) 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 purpose 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, 2005, the company would have recognized a minimum pension liability of $87 million (2004 – $66 million), an intangible asset of $9 million (2004 – $11 million) and an other comprehensive loss of $51 million, net of income taxes of $27 million (2004 – $36 million, net of income taxes of $19 million). Other comprehensive income for the year ended December 31, 2005 would have decreased by $15 million, net of income taxes of $8 million (2004 – an increase in other comprehensive income of $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).

**(e) Cumulative Foreign Currency Translation**

Under Canadian GAAP, foreign currency losses of $26 million (2004 – $29 million) arising on translation of the company's U.S. 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.

**(f) Variable Interest Entities**

For U.S. GAAP purposes, the company consolidated the VIE related to the sale of equipment as described in note 10c 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

materials and supplies inventory of $8 million and an increase to long-term debt of $22 million. The VIE was consolidated for Canadian GAAP purposes effective January 1, 2005 without restatement of prior periods (see note 1).

The accounts receivable securitization program, as currently structured, does not meet the FIN 46 (R) criteria for consolidation by Suncor (see note 10c).

**(g) Suspended Exploratory Well Costs**

Effective January 1, 2005, Suncor adopted Financial Accounting Standards Board Staff Position 19-1 (FSP 19-1), "Accounting for Suspended Well Costs". FSP 19-1 amended Statement of Financial Accounting Standards No. 19 (FAS 19), "Financial Accounting and Reporting by Oil and Gas Producing Companies", to permit the continued capitalization of exploratory well costs beyond one year if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project. There were no capitalized exploratory well costs charged to expense upon the adoption of FSP 19-1.

The table below provides details of the changes in the balance of suspended exploratory well costs as well as an aging summary of those costs.

**Change in Capitalized Suspended Exploratory Well Costs**

| ($ millions) | 2005 | 2004 | 2003 |
|---|---|---|---|
| Balance, beginning of year | **5** | 1 | — |
| Additions pending determination of proved reserves | **14** | 5 | 1 |
| Charged to dry hole expense | **(2)** | — | — |
| Reclassifications to proved properties | **(2)** | (1) | — |
| Balance, end of year | **15** | 5 | 1 |
| Capitalized for a period greater than one year ($ millions) | **1** | — | — |
| Number of projects that have exploratory well costs capitalized for a period greater than 12 months | **2** | — | — |



**h) Accounting for Purchases and Sales Inventory with the Same Counterparty**

Emerging Issues Task Force (EITF) Abstract No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty" addresses when it is appropriate to measure purchases and sales of inventory with the same counterparty at fair value and record them in revenues and cost of sales and when they should be recorded as exchanges measured at the book value of the item sold. The EITF concluded that purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another should be combined and recorded as exchanges measured at the book value of the item sold (net versus gross reported). The EITF is effective for transactions entered into subsequent to April 1, 2006.

As required by EITF 04-13, we record certain crude oil, natural gas, petroleum product and chemical purchases and sales entered into contemporaneously with the same counterparty on a net basis within the "purchases of crude oil and products" line in the Consolidated Statements of Earnings. These transactions are undertaken to ensure that the appropriate crude oil is at the appropriate refineries when required and that the appropriate products are available to meet customer demands. These transactions take place in the oil sands and downstream operating segments.

In addition, the R&M segment sells finished product and buys coker gas oil as a raw material to be used in the refining process from the same counterparty under terms specified in a single contract. These sales and purchases, as noted in the table below, are recorded at fair value in "revenue" and "purchases of crude oil and products" in the statements of income in accordance with the consensus for Issue 2 in EITF 04-13.

The purchase/sale of contract amounts included in revenue for 2005, 2004 and 2003 are shown below.

| ($ millions) | 2005 | 2004 | 2003 |
|---|---|---|---|
| Consolidated revenues | **11 086** | 8 665 | 6 611 |
| Amounts included in revenues for purchase/sale contracts with the same counterparty (1) | **16** | 7 | — |

(1) Associated costs are in "purchases of crude oil and products".

**Recently Issued Accounting Standards**

In December 2004, the U.S. Financial Accounting Standards Board issued SFAS 123(R), "Share-Based Payment". The standard, effective January 1, 2006, 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 the adoption of SFAS 123R on January 1, 2006, for U.S. GAAP reporting purposes will not have a significant impact on net earnings.

In 2005, the FASB issued SFAS 153, "Exchange of Non-monetary Assets". Effective January 1, 2006, all non-monetary transactions must be measured at fair value (if determinable) unless the transaction lacks commercial substance, or is an exchange of a product held for sale in the ordinary course of business, or is a product to be sold in the same line of business. Commercial substance exists when the company's future cash flows are expected to change significantly as a result of a transaction. The company will be required to record the effects of an existing contract at Oil Sands that exchanges off-gas produced as a by-product of the upgrading operations for natural gas. An equal amount of revenues for the sale of the off-gas, and purchases of crude oil and products for the purchase of the natural gas will be recorded. The amount of the gross

up of revenues and purchases of crude oil products will be dependent on the prevailing prices for natural gas. Currently the transaction is recorded net in purchases of crude oil and products. Retroactive adjustment is prohibited by the standard.

In May 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections". Among other changes, this Statement requires retrospective application for voluntary changes in accounting principle, unless it is impractical to do so. This Statement is effective on a prospective basis beginning January 1, 2006.

In November 2004, the FASB issued SFAS No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4." This Statement clarifies that items, such as abnormal idle facility expense, excessive spoilage, double freight, and handling costs, be recognized as current-period charges. In addition, the Statement requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. Suncor is required to implement this Statement in 2006. The company does not expect the standard to have a significant impact on earnings or financial position.

The U.S. Emerging Issues Task Force (EITF) has issued EITF Abstract 04-6 "Accounting for Stripping Costs Incurred during Production in the Mining Industry". The abstract is effective January 1, 2006. The EITF consensus is that stripping (overburden removal) costs incurred during the production phase of a mine are variable production costs that should be included in the costs of inventory produced during the period. Up until December 31, 2005, the company has deferred and amortized stripping costs for Canadian GAAP purposes. The company is currently assessing whether to expense overburden stripping costs as incurred (see Summary of Significant Accounting Policies page 65).



**QUARTERLY SUMMARY** (unaudited)

**FINANCIAL DATA**

| | For the Quarter Ended | | | | | For the Quarter Ended | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **($ millions except per share amounts)** | **Mar 31 2005** | **June 30 2005** | **Sept 30 2005** | **Dec 31 2005** | **Total Year 2005** | **Mar 31 2004** | **June 30 2004** | **Sept 30 2004** | **Dec 31 2004** | **Total Year 2004** |
| **Revenues** | **2 061** | **2 380** | **3 142** | **3 503** | **11 086** | 1 806 | 2 212 | 2 326 | 2 321 | 8 665 |
| **Net earnings (loss)** | | | | | | | | | | |
| Oil Sands | **117** | **117** | **253** | **586** | **1 073** | 239 | 231 | 263 | 261 | 994 |
| Natural Gas | **26** | **27** | **24** | **78** | **155** | 22 | 35 | 23 | 35 | 115 |
| Energy Marketing and Refining – Canada | **(3)** | **5** | **17** | **22** | **41** | 30 | (3) | 29 | 24 | 80 |
| Refining and Marketing – U.S.A. (c) | **6** | **31** | **50** | **55** | **142** | (3) | 12 | 15 | 10 | 34 |
| Corporate and eliminations | **(48)** | **(68)** | **(3)** | **(47)** | **(166)** | (72) | (73) | 7 | 3 | (135) |
| | **98** | **112** | **341** | **694** | **1 245** | 216 | 202 | 337 | 333 | 1 088 |
| **Per common share** | | | | | | | | | | |
| Net earnings attributable to common shareholders | | | | | | | | | | |
| Basic | **0.22** | **0.24** | **0.75** | **1.52** | **2.73** | 0.48 | 0.45 | 0.74 | 0.73 | 2.40 |
| Diluted | **0.21** | **0.24** | **0.73** | **1.48** | **2.67** | 0.46 | 0.43 | 0.73 | 0.72 | 2.36 |
| Cash dividends | **0.06** | **0.06** | **0.06** | **0.06** | **0.24** | 0.05 | 0.06 | 0.06 | 0.06 | 0.23 |
| **Cash flow from (used in) operations** | | | | | | | | | | |
| Oil Sands | **252** | **215** | **445** | **983** | **1 895** | 365 | 421 | 509 | 457 | 1 752 |
| Natural Gas | **83** | **81** | **104** | **144** | **412** | 83 | 90 | 80 | 66 | 319 |
| Energy Marketing and Refining – Canada | **22** | **26** | **44** | **60** | **152** | 56 | 23 | 52 | 57 | 188 |
| Refining and Marketing – U.S.A. (c) | **18** | **52** | **82** | **95** | **247** | (6) | 21 | 21 | 23 | 59 |
| Corporate and eliminations | **(81)** | **(69)** | **(24)** | **(56)** | **(230)** | (84) | (65) | (77) | (79) | (305) |
| | **294** | **305** | **651** | **1 226** | **2 476** | 414 | 490 | 585 | 524 | 2 013 |
| | | | | | | | | | | |
| **OPERATING DATA** | | | | | | | | | | |
| **OIL SANDS** (thousands of barrels per day) | | | | | | | | | | |
| **Production** (1) | | | | | | | | | | |
| Base operations | **121.2** | **119.5** | **125.2** | **263.3** | **157.6** | 213.9 | 210.8 | 230.2 | 206.9 | 215.6 |
| Firebag | **18.7** | **8.7** | **23.0** | **26.0** | **19.1** | 5.9 | 15.1 | 7.3 | 15.6 | 10.9 |
| | **139.9** | **128.2** | **148.2** | **267.7** | **171.3** | 219.8 | 225.9 | 237.5 | 222.5 | 226.5 |
| **Sales** | | | | | | | | | | |
| Light sweet crude oil | **75.3** | **48.3** | **69.9** | **108.6** | **73.3** | 112.2 | 118.7 | 113.5 | 115.3 | 114.9 |
| Diesel | **11.8** | **9.0** | **10.6** | **30.7** | **15.6** | 27.5 | 29.7 | 28.7 | 25.5 | 27.9 |
| Light sour crude oil | **38.5** | **54.2** | **41.7** | **104.2** | **59.8** | 74.3 | 68.9 | 76.3 | 80.9 | 75.1 |
| Bitumen | **18.4** | **9.6** | **22.3** | **7.2** | **16.6** | — | 14.5 | 7.9 | 11.0 | 8.4 |
| | **144.0** | **121.1** | **144.5** | **250.7** | **165.3** | 214.0 | 231.8 | 226.4 | 232.7 | 226.3 |

| | For the Quarter Ended | | | | | For the Quarter Ended | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Mar 31 2005 | June 30 2005 | Sept 30 2005 | Dec 31 2005 | Total Year 2005 | Mar 31 2004 | June 30 2004 | Sept 30 2004 | Dec 31 2004 | Total Year 2004 |
| **OPERATING DATA** (continued) | | | | | | | | | | |
| **OIL SANDS** (continued) | | | | | | | | | | |
| **Average sales price** (2) (dollars per barrel) | | | | | | | | | | |
| Light sweet crude oil | **45.41** | **39.20** | **52.08** | **55.96** | **49.93** | 40.26 | 45.70 | 46.03 | 50.55 | 45.60 |
| Other (diesel, light sour crude oil and bitumen) | **47.31** | **50.47** | **59.70** | **63.84** | **56.90** | 35.85 | 38.28 | 42.29 | 39.62 | 39.13 |
| Total | **46.44** | **45.98** | **56.01** | **60.42** | **53.81** | 38.16 | 41.88 | 44.08 | 44.68 | 42.28 |
| Total (a) | **54.80** | **57.24** | **67.95** | **66.68** | **62.68** | 43.28 | 48.18 | 52.72 | 54.40 | 49.78 |
| **Cash operating costs and total operating costs – Base Operations** (dollars per barrel sold rounded to the nearest $0.05) | | | | | | | | | | |
| Cash costs | **15.10** | **16.30** | **18.00** | **12.90** | **14.95** | 9.65 | 9.75 | 9.00 | 10.90 | 9.80 |
| Natural gas | **4.70** | **2.65** | **4.60** | **3.40** | **3.75** | 2.10 | 2.30 | 1.40 | 2.20 | 2.00 |
| Firebag bitumen | **—** | **—** | **—** | **1.60** | **0.75** | — | — | — | — | — |
| Imported bitumen | **0.10** | **—** | **—** | **0.10** | **0.05** | 0.40 | 0.05 | 0.10 | 0.10 | 0.15 |
| **Cash operating costs** (3) | **19.90** | **18.95** | **22.60** | **18.00** | **19.50** | 12.15 | 12.10 | 10.50 | 13.20 | 11.95 |
| Firebag start-up costs | **—** | **—** | **—** | **0.30** | **0.10** | 1.20 | — | — | — | 0.30 |
| **Total cash operating costs** (4) | **19.90** | **18.95** | **22.60** | **18.30** | **19.60** | 13.35 | 12.10 | 10.50 | 13.20 | 12.25 |
| Depreciation, depletion and amortization | **9.05** | **9.45** | **9.00** | **6.20** | **8.00** | 6.20 | 6.20 | 5.70 | 6.25 | 6.10 |
| **Total operating costs** (5) | **28.95** | **28.40** | **31.60** | **24.50** | **27.60** | 19.55 | 18.30 | 16.20 | 19.45 | 18.35 |
| **Cash operating costs and total operating costs – Firebag** | | | | | | | | | | |
| Cash costs | **8.90** | **18.95** | **6.85** | **6.25** | **8.45** | — | 6.55 | 14.90 | 7.00 | 8.30 |
| Natural gas | **10.10** | **16.40** | **13.70** | **13.40** | **13.05** | — | 11.65 | 11.90 | 10.45 | 11.20 |
| **Cash operating costs** (6) | **19.00** | **35.35** | **20.55** | **19.65** | **21.50** | — | 18.20 | 26.80 | 17.45 | 19.50 |
| Depreciation, depletion and amortization | **4.75** | **7.60** | **4.10** | **4.60** | **4.90** | — | 5.80 | 7.45 | 5.55 | 6.00 |
| **Total operating costs** (7) | **23.75** | **42.95** | **24.65** | **24.25** | **26.40** | — | 24.00 | 34.25 | 23.00 | 25.50 |
| **NATURAL GAS** | | | | | | | | | | |
| **Gross production** (b) | | | | | | | | | | |
| Natural gas (millions of cubic feet per day) | **191** | **175** | **200** | **193** | **190** | 197 | 209 | 201 | 193 | 200 |
| Natural gas liquids (thousands of barrels per day) | **3.0** | **2.2** | **2.2** | **2.3** | **2.4** | 2.2 | 2.2 | 2.6 | 2.9 | 2.5 |
| Crude oil (thousands of barrels per day) | **0.9** | **1.0** | **0.7** | **0.6** | **0.8** | 0.9 | 1.1 | 1.0 | 1.0 | 1.0 |
| Total (barrels of oil equivalent per day at 6:1 for natural gas) | **35.7** | **32.4** | **36.3** | **35.0** | **34.8** | 35.9 | 38.1 | 37.1 | 36.1 | 36.8 |
| **Average sales price** (2) | | | | | | | | | | |
| Natural gas (dollars per thousand cubic feet) | **6.81** | **7.29** | **8.32** | **11.66** | **8.57** | 6.54 | 6.77 | 6.49 | 7.02 | 6.70 |
| Natural gas (a) (dollars per thousand cubic feet) | **6.74** | **7.26** | **8.34** | **11.83** | **8.59** | 6.59 | 6.84 | 6.53 | 6.98 | 6.73 |
| Natural gas liquids (dollars per barrel) | **38.32** | **52.52** | **58.00** | **57.85** | **50.70** | 38.13 | 43.53 | 42.06 | 46.46 | 42.82 |
| Crude oil – conventional (dollars per barrel) | **61.40** | **63.86** | **63.77** | **72.60** | **64.85** | 44.14 | 47.08 | 55.43 | 55.26 | 50.41 |



| | For the Quarter Ended | | | | | For the Quarter Ended | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Mar 31 2005 | June 30 2005 | Sept 30 2005 | Dec 31 2005 | Total Year 2005 | Mar 31 2004 | June 30 2004 | Sept 30 2004 | Dec 31 2004 | Total Year 2004 |
| **OPERATING DATA** (continued) | | | | | | | | | | |
| **ENERGY MARKETING AND REFINING – CANADA** | | | | | | | | | | |
| Refined product sales (thousands of cubic metres per day) | **15.1** | **16.1** | **15.6** | **14.3** | **15.2** | 15.2 | 15.5 | 15.3 | 15.6 | 15.4 |
| Margins | | | | | | | | | | |
| Refining (8) (cents per litre) | **4.8** | **7.3** | **9.2** | **9.0** | **7.6** | 7.8 | 7.4 | 8.8 | 7.9 | 8.0 |
| Refining (8), (a) (cents per litre) | **4.8** | **7.6** | **10.1** | **9.3** | **8.0** | 7.8 | 8.0 | 8.8 | 7.8 | 8.1 |
| Retail (9) (cents per litre) | **4.7** | **3.8** | **5.4** | **6.4** | **5.1** | 5.0 | 4.3 | 3.7 | 4.5 | 4.4 |
| Utilization of refining capacity (%) | **91** | **100** | **96** | **95** | **95** | 108 | 85 | 104 | 101 | 100 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **REFINING AND MARKETING – U.S.A.** (c) | | | | | | | | | | |
| Refined product sales (thousands of cubic metres per day) | **10.1** | **12.6** | **17.3** | **14.5** | **13.7** | 8.1 | 8.9 | 10.9 | 9.5 | 9.3 |
| Margins | | | | | | | | | | |
| Refining (8) (cents per litre) | **6.3** | **9.5** | **8.9** | **10.4** | **9.0** | 5.0 | 9.0 | 5.1 | 7.7 | 6.7 |
| Refining (8), (a) (cents per litre) | **6.3** | **9.5** | **8.9** | **10.4** | **9.0** | 5.0 | 9.3 | 5.3 | 7.7 | 6.8 |
| Retail (9) (cents per litre) | **3.3** | **4.3** | **7.5** | **5.4** | **5.1** | 5.0 | 6.2 | 4.2 | 6.0 | 5.4 |
| Utilization of refining capacity (%) | **96** | **102** | **104** | **91** | **98** | 85 | 86 | 99 | 100 | 92 |

(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 results of operations from assets acquired May 31, 2005.

**Definitions**

(1) Total production – In the fourth quarter of 2005, base operations production included barrels from both mining and in-situ operations that were upgraded. Firebag production reported in the operating summary includes all in-situ production irrespective of whether it was upgraded or sold to third parties. As such these production figures as reported in the operating summary are not additive in the fourth quarter of 2005 and the year ended December 31, 2005.
(2) Average sales price – Calculated before royalties and net of related transportation costs (including or excluding the impact of hedging activities as noted).
(3) 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 that are processed through the upgrader facilities. For a reconciliation of this non GAAP financial measure see page 57 of MD&A.
(4) 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 all production volumes that are processed through the upgrader facilities.
(5) 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 all production volumes that are processed through the upgrader facilities.
(6) 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.
(7) 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.
(8) Refining margin – Calculated as the average wholesale unit price from all products less average unit cost of crude oil.
(9) 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, as applicable, and other adjustments, less refining gasoline transfer price.

**Metric conversion**

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



**FIVE-YEAR FINANCIAL SUMMARY** (unaudited)

| **($ millions except for ratios)** | **2005(a)** | **2004** | **2003(a)** | **2002** | **2001** |
|---|---|---|---|---|---|
| **Revenues** | | | | | |
| Oil Sands | **3 965** | 3 640 | 3 101 | 2 655 | 1 404 |
| Natural Gas | **679** | 567 | 512 | 339 | 481 |
| Energy Marketing and Refining – Canada | **4 299** | 3 460 | 2 936 | 2 508 | 2 673 |
| Refining and Marketing – U.S.A. | **2 621** | 1 495 | 515 | — | — |
| Corporate and eliminations | **(478)** | (497) | (453) | (431) | (232) |
| | **11 086** | 8 665 | 6 611 | 5 071 | 4 326 |
| **Net earnings (loss)** | | | | | |
| Oil Sands | **1 073** | 994 | 887 | 781 | 271 |
| Natural Gas | **155** | 115 | 120 | 34 | 116 |
| Energy Marketing and Refining – Canada | **41** | 80 | 53 | 61 | 79 |
| Refining and Marketing – U.S.A. | **142** | 34 | 18 | — | — |
| Corporate and eliminations | **(166)** | (135) | 9 | (156) | (117) |
| | **1 245** | 1 088 | 1 087 | 720 | 349 |
| **Cash flow from (used in) operations** | | | | | |
| Oil Sands | **1 895** | 1 752 | 1 803 | 1 475 | 486 |
| Natural Gas | **412** | 319 | 298 | 164 | 280 |
| Energy Marketing and Refining – Canada | **152** | 188 | 164 | 112 | 165 |
| Refining and Marketing – U.S.A. | **247** | 59 | 34 | — | — |
| Corporate and eliminations | **(230)** | (305) | (259) | (358) | (132) |
| | **2 476** | 2 013 | 2 040 | 1 393 | 799 |
| **Capital and exploration expenditures** | | | | | |
| Oil Sands | **1 948** | 1 119 | 953 | 618 | 1 495 |

| | | | | | |
|---|---|---|---|---|---|
| Natural Gas | **363** | 279 | 184 | 163 | 132 |
| Energy Marketing and Refining – Canada | **442** | 228 | 122 | 60 | 54 |
| Refining and Marketing – U.S.A. | **337** | 190 | 31 | — | — |
| Corporate | **63** | 31 | 32 | 37 | 13 |
| | **3 153** | 1 847 | 1 322 | 878 | 1 694 |
| **Total assets** | **15 351** | 11 841 | 10 540 | 9 046 | 8 467 |
| | | | | | |
| **Capital employed** (b) | | | | | |
| Short-term and long-term debt, less cash and cash equivalents | **2 891** | 2 159 | 2 577 | 3 204 | 3 678 |
| Shareholders' equity | **6 130** | 4 921 | 3 893 | 2 886 | 2 220 |
| | **9 021** | 7 080 | 6 470 | 6 090 | 5 898 |
| Less capitalized costs related to major projects in progress | **(2 175)** | (1 467) | (1 122) | (511) | (3 691) |
| | **6 846** | 5 613 | 5 348 | 5 579 | 2 207 |
| | | | | | |
| **Total Suncor employees** (number at year-end) | **5 152** | 4 605 | 4 231 | 3 422 | 3 307 |



| | 2005 (a) | 2004 | 2003(a) | 2002 | 2001 |
|---|---|---|---|---|---|
| **Dollars per common share** | | | | | |
| Net earnings attributable to common shareholders | **2.73** | 2.40 | 2.42 | 1.61 | 0.78 |
| Cash dividends | **0.24** | 0.23 | 0.1925 | 0.17 | 0.17 |
| Cash flow from operations | **5.43** | 4.44 | 4.53 | 3.11 | 1.79 |
| | | | | | |
| **Ratios** | | | | | |
| Return on capital employed (%) (b), (c) | **20.9** | 19.0 | 18.3 | 14.5 | 17.8 |
| Return on capital employed (%) (d) | **15.3** | 16.1 | 16.0 | 13.7 | 7.3 |
| Return on shareholders' equity (%) (e) | **22.5** | 24.7 | 32.1 | 28.2 | 16.8 |
| Debt to debt plus shareholders' equity (%) (f) | **33.3** | 31.4 | 43.2 | 52.7 | 62.4 |
| Net debt to cash flow from operations (times) (g) | **1.2** | 1.1 | 1.3 | 2.3 | 4.6 |
| Interest coverage – cash flow basis (times) (h) | **16.9** | 13.8 | 11.5 | 8.1 | 4.2 |
| Interest coverage – net earnings basis (times) (i) | **13.4** | 10.9 | 10.1 | 6.2 | 2.5 |

(a) Refining and Marketing – U.S.A. reflects the results of operations since acquisitions on August 1, 2003 and May 31, 2005.
(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 twelve 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 Operating Summary is calculated in a manner consistent with consolidated ROCE. For a detailed annual reconciliation of this non GAAP financial measure see page 56 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.

| | For the Quarter Ended | | | | For the Quarter Ended | | | |
|---|---|---|---|---|---|---|---|---|
| | Mar 31 2005 | June 30 2005 | Sept 30 2005 | Dec 31 2005 | Mar 31 2004 | June 30 2004 | Sept 30 2004 | Dec 31 2004 |
| **Share ownership** | | | | | | | | |
| Average number outstanding, weighted monthly (thousands) (a) | **454 911** | **456 141** | **456 996** | **457 429** | 452 123 | 452 283 | 452 565 | 453 900 |
| **Share price** (dollars) | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Toronto Stock Exchange | | | | | | | | |
| High | **50.07** | **60.24** | **73.25** | **76.05** | 38.02 | 36.80 | 41.49 | 44.49 |
| Low | **38.76** | **44.00** | **57.75** | **57.00** | 31.62 | 30.95 | 32.80 | 38.20 |
| Close | **48.73** | **57.92** | **70.42** | **73.32** | 35.97 | 34.01 | 40.40 | 42.40 |
| New York Stock Exchange – US$ | | | | | | | | |
| High | **41.70** | **48.95** | **62.50** | **66.00** | 28.75 | 28.09 | 32.63 | 36.15 |
| Low | **31.33** | **35.38** | **47.40** | **48.09** | 24.68 | 22.55 | 24.90 | 31.16 |
| Close | **40.21** | **47.32** | **60.53** | **63.13** | 27.35 | 25.61 | 32.01 | 35.40 |
| **Shares traded** (thousands) | | | | | | | | |
| Toronto Stock Exchange | **107 080** | **102 317** | **108 384** | **107 502** | 100 401 | 109 073 | 102 460 | 86 424 |
| New York Stock Exchange | **84 285** | **89 244** | **139 214** | **175 618** | 45 120 | 59 254 | 64 519 | 66 536 |
| **Per common share information** (dollars) | | | | | | | | |
| Net earnings attributable to common shareholders | **0.22** | **0.24** | **0.75** | **1.52** | 0.48 | 0.45 | 0.74 | 0.73 |
| Cash dividends | **0.06** | **0.06** | **0.06** | **0.06** | 0.05 | 0.06 | 0.06 | 0.06 |

(a) The company had approximately 2,420 holders of record of common shares as at January 31, 2006.

**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)

| | 2005 | 2004 | 2003 | 2002 | 2001 |
|---|---|---|---|---|---|
| **OIL SANDS** | | | | | |
| **Production** (thousands of barrels per day) | **171.3** | 226.5 | 216.6 | 205.8 | 123.2 |
| **Sales** (thousands of barrels per day) | | | | | |
| Light sweet crude oil | **73.3** | 114.9 | 112.3 | 104.7 | 56.2 |
| Diesel | **15.6** | 27.9 | 26.3 | 23.0 | 14.8 |
| Light sour crude oil | **59.8** | 75.1 | 73.3 | 68.3 | 42.0 |
| Bitumen | **16.6** | 8.4 | 6.4 | 9.3 | 8.5 |
| | **165.3** | 226.3 | 218.3 | 205.3 | 121.5 |
| **Average sales price** (dollars per barrel) | | | | | |
| Light sweet crude oil | **49.93** | 45.60 | 40.26 | 37.56 | 34.17 |
| Other (diesel, light sour crude oil and bitumen) | **56.90** | 39.13 | 33.93 | 29.58 | 24.86 |
| Total | **53.81** | 42.28 | 37.19 | 33.65 | 29.17 |
| Total (a) | **62.68** | 49.78 | 40.22 | 36.94 | 34.21 |
| Cash operating costs – base operations (b) | **19.50** | 11.95 | 11.45 | 11.15 | 11.35 |
| Total cash operating costs – base operations (b) | **19.60** | 12.25 | 11.45 | 11.15 | 11.35 |
| Total operating costs – base operations (b) | **27.60** | 18.35 | 17.25 | 17.25 | 16.70 |
| Cash operating costs – Firebag (b), (e) | **21.50** | 19.50 | — | — | — |
| Total operating costs – Firebag (b), (e) | **26.40** | 25.50 | — | — | — |
| Capital employed excluding major projects in progress | **4 633** | 4 169 | 4 050 | 4 512 | 1 378 |
| **Return on capital employed** (%) (c) | **24.3** | 22.9 | 20.8 | 16.7 | 19.6 |
| **Return on capital employed** (%) (d) | **17.6** | 18.8 | 17.4 | 15.6 | 6.2 |

(a) Excludes the impact of hedging activities.
(b) Dollars per barrel rounded to the nearest $0.05. See definitions on page 100.
(c) See definitions on page 102.
(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 stage 1 commenced commercial operations on April 1, 2004.



| 2005 | 2004 | 2003 | 2002 | 2001 |
|---|---|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| **NATURAL GAS** | | | | | |
| **Production** | | | | | |
| Natural gas (millions of cubic feet per day) | | | | | |
| Gross | **190** | 200 | 187 | 179 | 177 |
| Net | **137** | 147 | 142 | 124 | 124 |
| Natural gas liquids (thousands of barrels per day) | | | | | |
| Gross | **2.4** | 2.5 | 2.3 | 2.4 | 2.4 |
| Net | **1.9** | 1.8 | 1.7 | 1.7 | 1.7 |
| Crude oil (thousands of barrels per day) | | | | | |
| Gross | **0.8** | 1.0 | 1.4 | 1.5 | 1.5 |
| Net | **0.7** | 0.8 | 1.1 | 1.2 | 1.1 |
| Total (thousands of boe (a) per day) | | | | | |
| Gross | **34.8** | 36.8 | 34.9 | 33.7 | 33.4 |
| Net | **25.3** | 27.1 | 26.4 | 23.6 | 23.5 |
| | | | | | |
| **Average sales price** | | | | | |
| Natural gas (dollars per thousand cubic feet) | **8.57** | 6.70 | 6.42 | 3.91 | 6.09 |
| Natural gas (dollars per thousand cubic feet) (b) | **8.59** | 6.73 | 6.42 | 3.91 | 6.12 |
| Natural gas liquids (dollars per barrel) | **50.70** | 42.82 | 36.08 | 29.35 | 34.38 |
| Crude oil – conventional (dollars per barrel) | **64.85** | 50.41 | 40.29 | 31.72 | 33.92 |
| | | | | | |
| Capital employed | **563** | 448 | 400 | 422 | 291 |
| | | | | | |
| **Return on capital employed** (%) (e) | **30.7** | 27.1 | 29.2 | 9.5 | 34.2 |
| | | | | | |
| **Undeveloped landholdings** (c) | | | | | |
| Oil and gas (millions of acres) | | | | | |
| Western Canada | | | | | |
| Gross | **0.6** | 0.7 | 0.5 | 0.5 | 0.6 |
| Net | **0.4** | 0.5 | 0.4 | 0.4 | 0.5 |
| International | | | | | |
| Gross | **0.4** | 0.7 | 0.9 | 1.2 | 1.7 |
| Net | **0.2** | 0.4 | 0.2 | 0.7 | 1.3 |
| | | | | | |
| **Net wells drilled** (d) | | | | | |
| Exploratory | | | | | |
| Oil | **—** | — | — | — | — |
| Gas | **8** | 5 | 2 | 2 | 4 |
| Dry | **4** | 5 | 31 | 19 | 16 |
| Development | | | | | |
| Oil | **1** | — | 1 | — | — |
| Gas | **18** | 16 | 16 | 18 | 16 |
| Dry | **3** | — | 4 | 4 | 2 |
| | **34** | 26 | 54 | 43 | 38 |

(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 22 net exploratory wells and 10 net development wells in progress at the end of 2005.
(e) See definitions on page 102.



| | 2005 | 2004 | 2003 | 2002 | 2001 |
|---|---|---|---|---|---|
| **ENERGY MARKETING AND REFINING – CANADA** | | | | | |
| **Refined product sales** (thousands of cubic metres per day) | | | | | |
| Transportation fuels | | | | | |
| Gasoline | | | | | |
| Retail (b) | **4.5** | 4.6 | 4.4 | 4.5 | 4.3 |
| Other | **3.9** | 4.1 | 4.2 | 4.4 | 4.4 |
| Jet fuel | **0.9** | 0.9 | 0.7 | 0.4 | 0.7 |
| Diesel | **3.3** | 3.1 | 3.0 | 2.9 | 3.1 |
| | **12.6** | 12.7 | 12.3 | 12.2 | 12.5 |
| Petrochemicals | **0.7** | 0.8 | 0.8 | 0.6 | 0.5 |
| Heating oils | **0.4** | 0.4 | 0.5 | 0.4 | 0.4 |
| Heavy fuel oils | **1.0** | 0.7 | 0.8 | 0.6 | 0.8 |
| Other | **0.5** | 0.8 | 0.6 | 0.7 | 0.6 |
| | **15.2** | 15.4 | 15.0 | 14.5 | 14.8 |
| **Margins** (cents per litre) | | | | | |
| Refining | **7.6** | 8.0 | 6.5 | 4.8 | 5.7 |

| | | | | | |
|---|---|---|---|---|---|
| Refining (c) | **8.0** | 8.1 | 6.4 | 4.8 | 5.7 |
| Retail | **5.1** | 4.4 | 6.6 | 6.6 | 6.6 |
| **Crude oil supply and refining** | | | | | |
| Processed at Sarnia refinery (thousands of cubic metres per day) | **10.6** | 11.1 | 10.5 | 10.6 | 10.2 |
| Utilization of refining capacity (%) | **95** | 100 | 95 | 95 | 92 |
| Capital employed excluding major projects in progress | **486** | 512 | 551 | 485 | 480 |
| **Return on capital employed** (%) (d) | **8.1** | 14.6 | 10.3 | 12.0 | 18.3 |
| **Return on capital employed** (%) (d), (e) | **5.2** | 13.6 | 10.3 | 12.0 | 18.3 |
| **Retail outlets** (f) (number at year-end) | **374** | 378 | 379 | 384 | 400 |



| | 2005 | 2004 | 2003 | 2002 | 2001 |
|---|---|---|---|---|---|
| **REFINING AND MARKETING – U.S.A. (a)** | | | | | |
| **Refined product sales** (thousands of cubic metres per day) | | | | | |
| Transportation fuels | | | | | |
| Gasoline | | | | | |
| Retail | **0.7** | 0.7 | 0.7 | — | — |
| Other | **6.2** | 3.8 | 3.5 | — | — |
| Jet fuel | **0.8** | 0.5 | 0.5 | — | — |
| Diesel | **3.3** | 2.2 | 2.3 | — | — |
| | **11.0** | 7.2 | 7.0 | — | — |
| Asphalt | **1.6** | 1.5 | 1.7 | — | — |
| Other | **1.1** | 0.6 | 0.4 | — | — |
| | **13.7** | 9.3 | 9.1 | — | — |
| **Margins** (cents per litre) | | | | | |
| Refining | **9.0** | 6.7 | 5.9 | — | — |
| Refining (c) | **9.0** | 6.8 | 5.9 | — | — |
| Retail | **5.1** | 5.4 | 5.6 | — | — |
| **Crude oil supply and refining** | | | | | |
| Processed at Denver refinery (thousands of cubic metres per day) | **12.1** | 8.8 | 9.4 | — | — |
| Utilization of refining capacity (%) | **98** | 92 | 98 | — | — |
| Capital employed excluding major projects in progress | **327** | 232 | 270 | — | — |
| **Return on capital employed** (%) (d), (h) | **49.4** | 12.2 | — | — | — |
| **Return on capital employed** (%) (d), (e), (h) | **28.9** | 11.0 | — | — | — |
| **Retail outlets** (g) (number at year-end) | **43** | 43 | 43 | — | — |

(a) Refining and Marketing – U.S.A. reflects the results of operations since acquisitions on August 1, 2003 and May 31, 2005.
(b) Excludes sales through joint venture interests.
(c) Excludes the impact of hedging activities.
(d) See definitions on page 102.
(e) If capital employed were to include capitalized costs related to major projects in progress, the return on capital employed (ROCE) 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. In 2005, Suncor paid an aggregate dividend of $0.24 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 in the stock information section of 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**

GLJ Petroleum Consultants Ltd.

**Annual Meeting**

Suncor's annual general meeting of shareholders will be held at 10:30 a.m. MT on April 26, 2006, at the Metropolitan Centre, 333 Fourth Avenue S.W., Calgary, Alberta. Presentations from the meeting will be web-cast live at www.suncor.com/webcasts.

**Corporate Office**

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**For further information, to subscribe or cancel duplicate mailings**

In addition to annual and quarterly reports, Suncor publishes a biennial Report on Sustainability. All Suncor 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, go to the newsroom section of our website. To order copies of Suncor's print materials call 1-800-558-9071.

If you do not receive our annual or quarterly report, but would like to receive these reports regularly, call Computershare Trust Company of Canada at 1-877-982-8760 or visit their website at www.computershare.com. Computershare will update your account information accordingly.

Shareholders may elect to receive Suncor's Annual Report and other documents electronically. To register for electronic delivery, registered shareholders should visit www.computershare.com.



## 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, standards of business conduct and communication with investors and other stakeholders. 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 on Suncor's website at www.suncor.com/financialreporting or by calling 1-800-558-9071.

**Independence**

As of December 31, 2005, Suncor's Board of Directors comprised 12 directors, 11 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. All Board committees are comprised entirely of independent directors.

| 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. 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 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. |

**Share Ownership**

The Board has set guidelines for its own, as well as executive share ownership. These guidelines, as well as the amount of shares held by each Board member and named executive are reported annually in Suncor's management proxy circular.



**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 is also president of the Shaw Foundation and serves as a director of Darian Resources. Mr. Shaw is 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. In 2000 Mr. Benson retired from a major international oil company. Mr. Benson is also a director of PanGlobal Energy Ltd., Kanetax Energy Inc. and Tenax Inc. He is active with several charitable organizations including Shock Trauma Air Rescue Services (STARS), the Council for Advancement of Native Development Officers and the Canadian Aboriginal Professional Association. He is also a member of the Board of Governors for the Northern Alberta Institute of Technology.

**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 is also a director and chair of the governance committee of the Canadian Public Accountability Board. In 1998, Mr. Canfield was appointed to the Order of British Columbia.

**Bryan P. Davies** (1),(4)
**Toronto, Ontario**
**Director 1991 to 1996 and since 2000**

Bryan Davies is president of Davtak (Canada) Inc., a policy consulting firm based in Toronto. He is also a director of the General Insurance Statistical Agency. He is past superintendent of the Financial Services Commission of Ontario. Prior to that he was senior vice president of regulatory affairs, with the Royal Bank Financial Group. Mr. Davies is also active with numerous not-for-profit and charitable organizations, including serving as past 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 on the board and chair of the audit committee of Epcor Power LP. He is also a member of the board of Precision Drilling Corporation and Fairquest Energy Ltd. 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 Athol Murray College of Notre Dame, and board member of the Canadian Unity Council and Calgary Arts Development Authority. Mr. Felesky is a member of the Order of Canada.

**John T. Ferguson** (1),(2)
**Edmonton, Alberta**
**Chair, Audit Committee**
**Director since 1995**

John Ferguson is founder and chairman of the Board of Princeton Developments Ltd., a real estate company in Edmonton, Alberta. Mr. Ferguson is also a director of Fountain Tire Ltd., the Royal Bank of Canada and Strategy Summit Ltd. He is a director of the C.D. Howe Institute, the Alberta Bone and Joint 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 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 director 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, including the American Bureau of Shipping, the Marine Resources Foundation, and St. Luke's Episcopal Hospital in Houston.



**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 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 four structured split share funds traded on the TSX 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 the president of VPI Investments Ltd., a private investment holding company. Mrs. McCaig is actively involved with charitable and community activities. She is currently chair of the Alberta Adolescent Recovery Centre, co-chair of the Alberta Children's Hospital Foundation $50 million All for One – All for Kids campaign, a trustee of the Killam Estate, chair of the Calgary Health Trust, a director of the Calgary Stampede Foundation and honorary chair of the Alberta Bone and Joint Institute. She is also chancellor emeritus of the University of Calgary and a member of the Order of Canada.

**Michael W. O'Brien** (1),(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. From 1992 to 2000, Mr. O'Brien was executive vice president of Suncor's wholly-owned subsidiary, Suncor Energy Products Inc. (formerly Sunoco Inc.). Mr. O'Brien also serves on the boards of PrimeWest Energy Inc. and Shaw Communications Inc. As well, he is past chair of the board of trustees for Nature Conservancy of Canada, past-chair of Canadian Petroleum Products Institute and past-chair of Canada's Voluntary Challenge for Global Climate Change.

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

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.

Suncor's most recently filed Form 40-F included, as exhibits, the certifications of our Chief Executive Officer and Chief Financial Officer required by sections 302 and 906 of the United States Sarbanes-Oxley Act of 2002.



**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

**Bart W. Demosky**
Vice President and 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

**Jay Thornton**
Senior Vice President,
Business Integration

**Steven W. Williams**
Executive Vice President,
Oil Sands

Offices shown are positions held by the officers in relation to businesses of Suncor Energy Inc. and its subsidiaries. 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 Canada based downstream subsidiaries, Suncor Energy Marketing Inc. and Suncor Energy Products Inc., respectively, and Mr. Nabholz, Ms. Lee and Mr. Thornton are officers of Suncor Energy Services Inc., which provides major projects management, human resources and communication, business integration and other shared services to the Suncor group of companies.

**MANAGEMENT'S DISCUSSION AND ANALYSIS**
March 1, 2006

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 58 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 (ROCE) 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 56.

Certain prior year 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 "we," "our," "us," "Suncor" or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships 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 (SEC), including periodic quarterly and annual reports and the Annual Information Form (AIF) filed with the SEC under cover of Form 40-F, is available on-line at www.sedar.com, www.sec.gov and our website www.suncor.com.

In order to provide shareholders with full disclosure relating to potential future capital expenditures, we have 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. For a further discussion of our significant capital projects and the range of cost estimates associated with an "on-budget" project, refer to note 1 under "Significant Capital Project Update" on page 26.



**SUNCOR OVERVIEW AND STRATEGIC PRIORITIES**

Suncor Energy Inc. is an integrated energy company headquartered in Calgary, Alberta. We operate four businesses:

- **Oil Sands**, located near Fort McMurray, Alberta, produces bitumen recovered from oil sands through mining and in-situ technology and upgrades it into 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 internal natural gas consumption in our oil sands and downstream operations.
- **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. EM&R also manages our 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 90,000 bpd of refining capacity in Commerce City, Colorado as well as related pipeline assets. R&M markets refined petroleum products to customers throughout Colorado.

Suncor's strategic priorities are:

***Operational:***

- Developing our oil sands resource base through mining and in-situ technology and supplementing Suncor bitumen production with third party supply.
- Expanding Oil Sands mine, in-situ, 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 our ongoing operations and growth plans.
- Maintaining a strong focus on worker, contractor and community safety.
- Pursuing new technology applications to increase production and reduce costs and environmental impacts.

***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 offset purchases for internal consumption.
- Maintaining a strong balance sheet by controlling debt and closely managing capital cost outlays.
- Targeting opportunities that have the potential to support a minimum 15% return on capital employed (ROCE) assuming a US$35 West Texas Intermediate (WTI) crude oil price and a Cdn$/US$ exchange rate of $0.80.



**2005 Overview**

- In September we completed rebuilding portions of our Oil Sands plant that were damaged by fire on January 4, 2005. The recovery and planned maintenance work was completed on schedule and the plant was running at full capacity by the end of September.
- In October, we successfully commissioned an expansion of our Oil Sands facilities that increased production capacity to 260,000 bpd from the previous capacity of 225,000 bpd. The project was completed on schedule and on budget. Work to further expand Oil Sands production capacity to 350,000 bpd in 2008 also progressed during the year and is on schedule and on budget.
- Construction of the second stage of our Firebag in-situ operation was completed on schedule and on budget. Commercial operations are expected to commence in the first quarter of 2006.
- In 2005, we produced 190 million cubic feet per day (mmcf/d) of natural gas from our conventional upstream operations compared to 200 mmcf/d in 2004. The decline was primarily due to weather related drilling delays and unplanned maintenance. Production remained in excess of volumes purchased for use in our Oil Sands and downstream operations.
- On May 31, 2005, we acquired the Colorado Refining Company from Valero Energy Corp., which included a 30,000 bpd refinery located adjacent to our existing refinery in Commerce City, Colorado. This combined operation is now the largest refining complex in the U.S. Rocky Mountain region.
- Construction continued on modifications to our Sarnia and Commerce City refineries to meet low-sulphur fuels regulations that will take effect in 2006.
- Maintaining a strong balance sheet remains a priority. Despite the impact of costs associated with the fire recovery, and an increase in capital spending to $2.8 billion (excluding the cost of the fire rebuild and capitalized interest), net debt (including cash and cash equivalents) at December 31, 2005 was $2.9 billion (1.2 times cash flow from operations), compared to $2.2 billion (1.1 times cash flow from operations) at December 31, 2004.
- Our company-wide ROCE (excluding major projects in progress) was 20.9% compared to 19% in 2004.



**SELECTED FINANCIAL INFORMATION**

**Annual Financial Data**

| Year ended December 31 ($ millions except per share data) | 2005 | 2004 | 2003 |
|---|---|---|---|
| Revenues | **11 086** | 8 665 | 6 611 |
| Net earnings | **1 245** | 1 088 | 1 087 |
| Total assets | **15 351** | 11 841 | 10 540 |
| Long-term debt | **3 007** | 2 217 | 2 934 |
| Dividends on common shares | **102** | 97 | 81 |
| Net earnings attributable to common shareholders per share – basic | **2.73** | 2.40 | 2.42 |
| Net earnings attributable to common shareholders per share – diluted | **2.67** | 2.36 | 2.26 |
| Cash dividends per share | **0.24** | 0.23 | 0.1925 |

**Outstanding Share Data**

| | |
|---|---|
| Number of common shares | 457 665 |
| Number of common share options | 19 203 |
| Number of common share options – exercisable | 9 361 |

**Quarterly Financial Data**

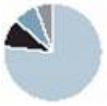
| ($ millions except per share) | 2005 Quarter ended Dec. 31 | Sept. 30 | June 30 | Mar. 31 | 2004 Quarter ended Dec. 31 | Sept. 30 | June 30 | Mar. 31 |
|---|---|---|---|---|---|---|---|---|
| Revenues | **3 503** | **3 142** | **2 380** | **2 061** | 2 321 | 2 326 | 2 212 | 1 806 |
| Net earnings | **694** | **341** | **112** | **98** | 333 | 337 | 202 | 216 |
| Net earnings attributable to common shareholders per share | | | | | | | | |
| Basic | **1.52** | **0.75** | **0.24** | **0.22** | 0.73 | 0.74 | 0.45 | 0.48 |
| Diluted | **1.48** | **0.73** | **0.24** | **0.21** | 0.72 | 0.73 | 0.43 | 0.46 |

**Net Earnings** (1)
Year ended December 31,
($ millions)



| | 05 | 04 | 03 |
|---|---|---|---|
| Oil Sands | **1 073** | 994 | 887 |
| Natural Gas | **155** | 115 | 120 |
| Energy Marketing and Refining – Canada | **41** | 80 | 53 |
| Refining and Marketing – U.S.A.(3) | **142** | 34 | 18 |

**Capital Employed**(1) (2)
Year ended December 31,
($ millions)



| | 05 | 04 | 03 |
|---|---|---|---|
| Oil Sands | **4 633** | 4 169 | 4 050 |
| Natural Gas | **563** | 448 | 400 |
| Energy Marketing and Refining – Canada | **486** | 512 | 551 |
| Refining and Marketing – U.S.A.(3) | **327** | 232 | 270 |

**Cash Flow from Operations** (1)
Year ended December 31,
($ millions)



| | 05 | 04 | 03 |
|---|---|---|---|
| Oil Sands | **1 895** | 1 752 | 1 803 |
| Natural Gas | **412** | 319 | 298 |
| Energy Marketing and Refining – Canada | **152** | 188 | 164 |
| Refining and Marketing – U.S.A.(3) | **247** | 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. Data for 2005 includes results of the former Colorado Refining Company, acquired May 31, 2005.



Fluctuations in quarterly net earnings for 2005 and 2004 were due to a number of factors:

- The January 2005 fire at Oil Sands significantly reduced crude oil production to approximately 122,000 bpd for the first nine months of 2005.

- U.S. dollar denominated crude oil and natural gas prices were higher on average in 2005 compared to 2004. WTI averaged US$56.55 per barrel (bbl) in 2005 compared to US$41.40/bbl in 2004, and Henry Hub natural gas prices averaged US$8.55/mcf in 2005, compared to US$6.20/mcf in 2004.

- Cash operating costs fluctuated due to variations in Oil Sands production levels, the timing and amount of maintenance activities, and the price and 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 our downstream operations, seasonal fluctuations were reflected in higher demand for vehicle fuels and asphalt in summer and heating fuels in winter. Prices were also affected by decreased market supply as a result of hurricane activity in the Gulf of Mexico during the summer of 2005.

- Realized commodity prices were unfavourably impacted in 2005 and 2004 by increases in the Canadian dollar compared to the U.S. dollar, which reduced the Canadian dollar revenues earned. The stronger Canadian dollar also resulted in net foreign exchange gains on U.S. dollar denominated debt in 2005 and 2004. The higher appreciation of the Canadian dollar compared to the U.S. dollar in 2004 over 2005 resulted in higher foreign exchange gains in 2004 compared to 2005.

- 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.

- The timing and amount of insurance receipts related to the fire at Oil Sands in January 2005.

**Consolidated Financial Analysis**

This analysis provides an overview of our consolidated financial results for 2005 compared to 2004. For a detailed analysis, see the various business segment analyses.

***Net Earnings***

Our net earnings were $1.245 billion in 2005, compared with $1.088 billion in 2004 (2003 – $1.087 billion). The increase was primarily due to higher U.S. dollar benchmark crude oil and natural gas prices, the receipt of insurance payments related to the January 2005 fire at our oil sands facility and lower hedging losses. These positive impacts were partially offset by lower Oil Sands and Natural Gas production, higher maintenance expenses, higher energy costs in our Oil Sands and downstream operations, and the impact of a stronger Canadian dollar.

**Net Earnings Components** (1)

| Year ended December 31 ($ millions, after-tax) | 2005 | 2004 | 2003 |
|---|---|---|---|
| Net earnings before the following items: | **1 114** | 1 242 | 1 021 |
| Firebag in-situ start-up costs (2) | **(4)** | (14) | — |
| Oil Sands fire accrued insurance proceeds (2) | **360** | — | — |
| Oil Sands Alberta Crown royalties | **(256)** | (261) | (21) |
| Impact of income tax rate reductions on opening net future income tax liabilities | **—** | 53 | (89) |
| Unrealized foreign exchange gains on U.S. dollar denominated long-term debt | **31** | 68 | 176 |
| Net earnings as reported | **1 245** | 1 088 | 1 087 |

(1) This table highlights 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 consolidated financial statements and notes in accordance with Canadian GAAP.
(2) Before deduction of Alberta Crown royalties.



**Industry Indicators**

| (Average for the year unless otherwise noted) | 2005 | 2004 | 2003 |
|---|---|---|---|
| West Texas Intermediate (WTI) crude oil US$/barrel at Cushing | **56.55** | 41.40 | 31.05 |
| Canadian 0.3% par crude oil Cdn$/barrel at Edmonton | **69.00** | 52.55 | 43.55 |
| Light/heavy crude oil differential US$/barrel WTI at Cushing less Lloydminster Blend at Hardisty | **20.90** | 13.55 | 8.65 |
| Natural gas US$/thousand cubic feet (mcf) at Henry Hub | **8.55** | 6.20 | 5.45 |
| Natural gas (Alberta spot) Cdn$/mcf at AECO | **8.50** | 6.80 | 6.70 |
| New York Harbour 3-2-1 crack US$/barrel (1) | **9.50** | 6.90 | 5.30 |
| Ontario refined product demand percentage change over prior year (2) | **0.2** | 4.3 | 2.5 |
| Colorado light product demand percentage change over prior year (3) | **3.3** | 7.2 | (2.2) |
| Exchange rate: Cdn$/US$ | **0.83** | 0.77 | 0.72 |

(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 2003 and 2004 are based on published government data. The figure for 2005 is an internal estimate based on preliminary government data.
(3) Figures for 2003 and 2004 are based on public reporting by state and government agencies. The 2005 figure is based on consensus estimates by third party consultants.

**Revenues** were $11.1 billion in 2005, compared with $8.7 billion in 2004 (2003 – $6.6 billion). The increase was primarily due to the following:

- Average commodity prices were higher in 2005 than in 2004. A 37% increase in average U.S. dollar WTI benchmark prices increased the selling price of Oil Sands crude oil production. Offsetting this increase, average light/heavy crude oil differentials compared to the WTI benchmark index widened by approximately 54%. As a result, the net price we received on certain sour crude oil and bitumen sales did not increase by as much as the increase in WTI.

- Refined product wholesale and retail prices in both EM&R and R&M were higher due to higher crude oil and refined product prices. In addition, a 47% increase in refined product sales volumes in R&M due to the acquisition of the Colorado Refining Company in the second quarter of 2005 had a positive impact on revenue.

- Lower strategic crude oil hedging losses increased revenues by $85 million. During 2005, we sold a portion of our crude oil production at fixed prices that were lower than prevailing market prices. During 2005 we sold 36,000 bpd at a fixed price of US$23/bbl compared to 79,000 bpd in 2004 at a fixed price range of US$21/bbl to US$24/bbl. Pretax hedging losses in 2005 were $535 million compared to $620 million in 2004.

- The recognition of $572 million pretax in net insurance proceeds related to the January 2005 fire at our Oil Sands operations.

Partially offsetting these increases were the following:

- An 8% increase in the average Cdn$/US$ exchange rate resulted in lower realizations on our crude oil sales basket and our 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 produced a corresponding reduction in the Canadian dollar value of our products.

- In 2005, Oil Sands sales volumes averaged 165,300 bpd, compared with 226,300 bpd in 2004 (2003 – 218,300 bpd). Decreased crude oil production as a result of the fire, and an inventory build in the fourth quarter resulted in lower sales volumes. Oil Sands sales in 2005 included 16,600 bpd of bitumen from Firebag in-situ operations (2004 – 8,400 bpd; 2003 – 6,400 bpd).

- Natural gas production averaged 190 mmcf/d in 2005 compared to 200 mmcf/d in 2004. Lower production was the result of weather related drilling delays that impacted the western Canadian industry, as well as unplanned maintenance.

Overall, higher prices, net of the impact of the higher Cdn$/US$ exchange rate, increased total revenues by approximately $2.2 billion and lower hedging losses increased revenues by approximately $85 million. These impacts were partially offset by lower sales volumes that decreased revenues by approximately $800 million.

**Purchases of crude oil and crude oil products** were $4.2 billion in 2005 compared with $2.9 billion in 2004 (2003 – $1.7 billion). The increase was primarily due to the following:

- Higher benchmark crude oil prices. This factor had the largest impact on product purchases for EM&R and R&M as WTI increased 37% over the prior year.



- Increased purchases of crude oil feedstock to utilize the additional refining capacity acquired by R&M in the second quarter of 2005. The acquisition increased our Commerce City refining capacity from 60,000 bpd to 90,000 bpd.

- Purchased volumes of crude oil and refined products decreased in EM&R. In 2004, larger amounts of refined products were purchased to meet customer demand during the maintenance shutdown that occurred in the second quarter.

- In 2004, the repurchase of crude oil originally sold to a Variable Interest Entity (VIE) in 1999 increased purchases at Oil Sands by approximately $55 million. There was no similar transaction in 2005.

**Operating, selling and general expenses** were $2.1 billion in 2005 compared with $1.8 billion in 2004 (2003 – $1.5 billion). The primary reasons for the increase were:

- Higher operating expenses primarily due to higher energy costs in our Oil Sands and downstream operations.

- Increased maintenance related costs at Oil Sands, primarily to ensure reliability of the upgrader that was not damaged by the fire.

- Higher stock-based compensation expenses caused by increases in our share price.

- Incremental operating costs associated with the acquisition of the Colorado Refining Company in 2005.

**Transportation and other expenses** were $152 million in 2005 compared to $132 million in 2004 (2003 – $135 million). In 2004, mark-to-market gains on inventory-related derivatives of $13 million in Oil Sands reduced transportation and other costs. Despite decreased production in our Oil Sands operations, transportation costs, excluding the mark-to-market gain from 2004, have remained relatively constant due to the "ship-or-pay" nature of the contracts with our shippers. Consistent with 2004, Oil Sands pipeline tolls continued to be reduced by initial shipper toll adjustments. These toll reductions are currently expected to continue until at least 2007.

**Depreciation, depletion and amortization** (DD&A) was $720 million in 2005, consistent with 2004 (2003 – $622 million). DD&A at Oil Sands decreased by $23 million due to lower overburden amortization as a result of lower production, partially offset by higher maintenance shutdown and catalyst amortization, and depletion incurred in in-situ operations. NG DD&A increased by $15 million, reflecting an increased proved asset base and higher amortization related to unproven lands.

**Royalty expenses** were $555 million in 2005 compared with $531 million in 2004 (2003 – $139 million). The increase in 2005 was primarily related to increased natural gas royalties due to higher price realizations, partially offset by lower natural gas volumes. For a discussion of Oil Sands Crown royalties, see page 27.

**Taxes other than income taxes** were $529 million in 2005 compared to $540 million in 2004 (2003 – $466 million). The decrease was primarily due to lower sales volumes subject to fuel excise taxes (FET) in our Oil Sands and EM&R operations, partially offset by higher sales volumes subject to FET in our R&M operations.

**Financing income** was $15 million in 2005 compared with expenses of $24 million in 2004 (2003 – income of $74 million). The decrease in expenses was primarily due to higher amounts of capitalized interest, lower effective interest rates and the effects of foreign exchange on U.S. dollar operating accounts, partially offset by a $45 million decrease in foreign exchange gains on our U.S. dollar denominated long-term debt. Interest expense, net of capitalized interest, was $32 million in 2005 compared to $95 million in 2004. Interest expense, net of capitalized interest, decreased primarily due to more capital projects meeting the criteria for interest capitalization.

**Income tax expense** was $742 million in 2005 (37% effective tax rate), compared to $530 million in 2004 (33% effective tax rate) (2003 – $718 million – 40% 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 $583 million (36% effective tax rate) and $629 million in 2003 (35% effective tax rate).

***Corporate Expenses***

After-tax corporate expenses were $166 million in 2005 compared to $135 million in 2004 (2003 – $9 million). The increase was due to higher stock-based compensation expenses and higher insurance related costs, partially offset by lower financing costs as discussed previously. Corporate had a net cash deficiency of $122 million in 2005, compared with $343 million in 2004 (2003 – $280 million). The reduced deficiency was primarily due to changes in working capital.



***Consolidated Cash Flow from Operations***

Cash flow from operations was $2.476 billion in 2005 compared to $2.013 billion in 2004 (2003 – $2.040 billion). The increase in cash flow from operations was primarily due to the same factors that impacted earnings, with the exception of foreign exchange gains on our U.S. dollar denominated long-term debt and future income taxes, both of which are non-cash items.

Total dividends paid during 2005 were $0.24 per share, compared with $0.23 per share in 2004. Suncor's Board of Directors periodically reviews the dividend policy, taking into consideration the company's capital spending profile, financial position, financing requirements, cash flow and other relevant factors. In the second quarter of 2004, the Board approved an increase in the quarterly dividend to $0.06 per share, from $0.05 per share.

**Dividends**

Total dividends paid during 2005 were $0.24 per share, compared with $0.23 per share in 2004. Suncor's Board of Directors periodically reviews the dividend policy, taking into consideration the company's capital spending profile, financial position, financing requirements, cash flow and other relevant factors. In the second quarter of 2004, the Board approved an increase in the quarterly dividend to $0.06 per share, from $0.05 per share.

***Oil Sands Fire***

On January 4, 2005, a fire at our Oil Sands operations damaged Upgrader 2, reducing production from base operations to approximately 122,000 bpd for the first nine months of the year. Repairs and scheduled maintenance were completed in September 2005, at which time operations returned to full production capacity.

We expect our property loss and business interruption (BI) insurance policies to significantly mitigate the financial impact of the fire. During 2005, we received $115 million (US$95 million) from our property loss policy and $594 million (US$500 million) in proceeds from our BI insurance policies, including $175 million (US$150 million) received in January and February 2006. The company is currently negotiating a final settlement with its business interruption insurers. Any subsequent proceeds will be recorded when unconditionally received or receivable.

For royalty purposes, BI proceeds are treated in the same manner as the revenues they replace and, accordingly, attract Alberta Crown royalties. For further discussion about Oil Sands Crown royalties, see page 27.

In the fourth quarter of 2005, we renewed our property and BI insurance programs. All of our policy limits and deductibles remain unchanged

except as noted. We carry primary and excess property loss and BI coverage with a combined limit up to US$1.150 billion, 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 BI 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.

The excess coverage of US$700 million can be used for either property loss or BI coverage for our Oil Sands operations. For BI purposes, this excess coverage is available commencing on the later of full utilization of the primary BI coverage or 90 days from the date of the incident. Effective January 1, 2006, the excess coverage has a ceiling of US$40/bbl WTI for purposes of determining the amount of BI losses.

***Liquidity and Capital Resources***

At December 31, 2005, our capital resources consisted primarily of cash flow from operations and available lines of credit. Our level of earnings and cash flow from operations depends on many factors, including commodity prices, production levels, downstream margins and Cdn$/US$ exchange rates. In 2005, cash flow from operations was negatively impacted by the fire at Oil Sands.

At December 31, 2005, our net debt (short and long-term debt less cash and cash equivalents) was approximately $2.9 billion compared to $2.2 billion at December 31, 2004. Approximately $710 million of the increase in total net debt in 2005 was the result of capital spending exceeding cash from operating activities.

In 2005, we entered into a new $600 million credit facility agreement with a one year term and also renewed $200 million of our available credit and term loan facilities. Our undrawn lines of credit at December 31, 2005 were approximately $1.3 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.

Interest expense on debt continues to be influenced by the composition of our debt portfolio, and we are benefiting from short-term floating interest rates continuing at low levels. To manage fixed versus floating rate exposure, we have 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 our growth plans. We believe a phased approach to existing and future growth projects should assist us in our efforts to maintain our ability to manage project costs and debt levels.



We believe we have the capital resources to fund our 2006 capital spending program of $3.5 billion and to meet current working capital requirements. If additional capital is required, we believe adequate additional financing is available at commercial terms and rates.

We anticipate our growth plan will be largely financed from internal cash flow, which is dependent on commodity prices, production levels and other factors, as well as debt.

After 2006, to support our growth strategy and sustain operations, we are projecting an annual capital spending program of approximately $3.5 billion. Actual spending is subject to change due to such factors as internal and external approvals and capital availability. Refer to the discussion under Risk Factors Affecting Performance on page 29 for additional factors that can have an impact on our ability to generate funds to support investing activities.

**Aggregate Contractual Obligations**

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| **($ millions)** | **Total** | **2006** | **2007-08** | **2009-10** | **Later Years** |
| Fixed-term debt, commercial paper (1) | 2 977 | 910 | 401 | — | 1 666 |
| Capital leases | 30 | 1 | 2 | 2 | 25 |
| Interest payments on fixed-term debt, commercial paper and capital leases (1) | 2 429 | 157 | 241 | 223 | 1 808 |
| Employee future benefits (2) | 457 | 33 | 74 | 84 | 266 |
| Asset retirement obligations (3) | 1 221 | 54 | 101 | 72 | 994 |
| Non-cancellable capital spending commitments (4) | 240 | 240 | — | — | — |
| Operating lease agreements, pipeline capacity and energy services commitments (5) | 5 408 | 258 | 507 | 529 | 4 114 |
| **Total** | **12 762** | **1 653** | **1 326** | **910** | **8 873** |

In addition to the enforceable and legally binding obligations quantified in the above table, we have other obligations for goods and services and raw materials entered into in the normal course of business, which may be terminated 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 $2,066 million of U.S. and Canadian dollar denominated debt that is redeemable at our option. Maturities range from 2007 to 2034. Interest rates vary from 5.95% to 7.15%. We entered into various interest rate swap transactions maturing in 2007 and 2011 that resulted in an average effective interest rate in 2005 ranging from 4.0% to 4.6% on $600 million of our medium term notes. Approximately $890 million of commercial paper with an effective interest rate of 3.2% was issued and outstanding at December 31, 2005.

(2) Represents the undiscounted expected funding by the company to its pension plans as well as benefit payments to retirees for other post-employment benefits.

(3) Represents the undiscounted amount of legal obligations associated with site restoration on the retirement of assets with determinable lives.

(4) Non-cancellable capital commitments related to capital projects totalled approximately $240 million at the end of 2005. In addition to capital

projects, we spend maintenance capital to sustain our current operations. In 2006, we anticipate spending approximately $700 million at our Oil Sands operations towards sustaining capital.

(5) Includes transportation service agreements for pipeline capacity, including 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.

We are subject to financial and operating covenants related to our public market and bank debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as defined 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 our 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 our debt ratings fall below investment grade status.

At December 31, 2005, we were in compliance with all covenants and our debt ratings were investment grade with a stable outlook. For more information, see page 24.



**Significant Capital Project Update**

We spent $2.8 billion ($3.2 billion including the cost of the fire rebuild and capitalized interest) on capital investing activities in 2005 compared to $1.825 billion in 2004. A summary of the progress on our significant projects under construction is provided below. All projects listed below have received Board of Directors approval.

| Description | Cost Estimate ($ millions) (1) | Spent in 2005 ($ millions) | Total Spent to Date ($ millions) | Status(1) |
|---|---|---|---|---|
| **Oil Sands** | | | | |
| Millennium vacuum unit | 425 | 60 | 450 | Project was completed on budget and on schedule. (2) |
| Firebag Stage 2 | 515 | 140 | 540 | Project was completed on budget and on schedule, commissioning is underway. (2) |
| Coker Unit (3) | 2 100 | 530 | 930 | Project is on schedule and on budget. |
| Firebag Cogeneration and expansion | 400 | 95 | 120 | Project is on schedule and on budget. |
| **EM&R** | | | | |
| Diesel desulphurization and oil sands integration | 800 | 295 | 475 | Project is on schedule and on budget. |
| **R&M** | | | | |
| Diesel desulphurization and oil sands integration | 465 (US$390) | 285 (US$235) | 420 (US$340) | Project cost estimate has been revised from $360 (US$300). |

(1) Estimating and budgeting for major capital projects is a process that involves uncertainties and that evolves in stages, each with progressively more refined data and a correspondingly narrower range of uncertainty. At very early stages, when broad engineering design specifications are developed, the level of uncertainty can result in price ranges with -30%/+50% (or similar) levels of uncertainty. As project engineering progresses, vendor bids are studied, goods and materials ordered and we move closer to the build stage, the level of uncertainty narrows. Generally, when projects receive final approval from our Board of Directors, our cost estimates have a range of uncertainty that has narrowed to the -10%/+10% or similar range. The projects noted in the above table have cost estimates within this range of uncertainty. These ranges establish an expected high and low capital cost estimate for a project. When we say that a project is “on budget”, we mean that we still expect the final project capital cost to fall within the current range of uncertainty for the project. Even at this stage, the uncertainties in the estimating process and the impact of future events, can and will cause actual results to differ, in some cases materially, from our estimates.

(2) Total project cost is subject to change until all accounts are final.

(3) Excludes costs associated with bitumen feed.

**Variable Interest Entities and Guarantees and Off-balance Sheet Arrangements**

At December 31, 2005, we had off-balance sheet arrangements with Variable Interest Entities (VIEs), and indemnification agreements with other third parties, as described below.

We have a securitization program in place to sell, on a revolving, fully serviced and limited recourse basis, up to $340 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, 2005, $340 million (2004 – $170 million) in outstanding accounts receivable had been sold under the program. Under the recourse provisions, we provide indemnification against credit losses for certain counterparties, for which indemnification did

not exceed $58 million in 2005. A contingent liability has not been recorded for this indemnification as we believe we have no significant exposure to credit losses. Proceeds received from new securitizations and proceeds from collections reinvested in securitizations on a revolving basis for the year ended December 31, 2005, were $170 million and approximately $2,220 million, respectively. We recorded an after-tax loss of approximately $4 million on the securitization program in 2005 (2004 – $2 million; 2003 – $3 million).

In 1999, we entered into an equipment sale and leaseback arrangement with a VIE for proceeds of $30 million. The VIE's sole asset is the equipment sold to it and leased back by Suncor. The VIE was consolidated effective January 1, 2005. The initial lease term covers a period of seven years. We have provided a residual value guarantee on the equipment of up to $7 million should we elect not to repurchase the equipment at the end of the lease term. Had we elected to terminate the lease at December 31, 2005, the total cost would have been $21 million (2004 – $25 million). Annualized equipment lease payments in 2005 were $5 million (2004 – $6 million; 2003 – $4 million).



We have agreed to indemnify holders of the 7.15% fixed-term U.S. dollar notes, the 5.95% fixed-term U.S. dollar notes and our credit facility lenders for added costs related 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. We are unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, we have the option to redeem or terminate these contracts if additional costs are incurred.

**Outlook**

During 2006, management will focus on the following operational priorities:

- Increase annual average Oil Sands production to 260,000 bpd at an average cash operating cost of $16.00 to $16.75 per barrel, assuming a natural gas price of US$6.75/mcf at Henry Hub.

- Increase natural gas production to an average of 205 to 210 mmcf/d. We will continue to focus on deep gas prospects.

- Advance plans for increased bitumen supply. Achieve full capacity operations from Firebag Stage 1 and a steady ramp up of production from Firebag Stage 2. On the mining side, we anticipate substantial completion of engineering for the new Steepbank mine extension and extraction facilities.

- Advance plans for increased upgrader capacity. Significant progress to take Suncor to 350,000 bpd in 2008 is anticipated with major progress on construction and vessel delivery. A regulatory hearing regarding our plans for increasing production to half a million barrels per day is anticipated, while engineering for that expansion progresses to the design specification stage.

- Advancing downstream integration plans. In 2006, we expect to complete modifications to the Commerce City and Sarnia refineries to allow low sulphur fuel production. The Commerce City refinery will undergo a major maintenance shutdown to support operational reliability and to tie in equipment that will enable it to process 10,000 to 15,000 bpd of Oil Sands sour crude blends. The Sarnia refinery will also undergo a major maintenance shutdown to support operational reliability.

- Focus on company-wide efficiency. To more seamlessly integrate operations and improve efficiency and productivity, we expect to complete the implementation of a company-wide enterprise resource planning (ERP) information and management system.

***Oil Sands Crown Royalties and Cash Income Taxes***

Under the current Province of Alberta oil sands royalty regime, Alberta Crown royalties for oil sands projects are payable at the rate of 25% of the difference between a project's annual gross revenues net of related transportation costs (R), less allowable costs including allowable capital expenditures (the R-C Royalty), subject to a minimum royalty, currently at 1% of R. The Alberta government has classified Suncor's current Oil Sands operations as two distinct "projects" for royalty purposes: Suncor's 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 under the government's generic bitumen-based royalty regime for oil sands projects. Pursuant to an agreement we concluded with the Government of Alberta during the third quarter of 2005, we settled the terms and conditions of our option to transition our base operations in 2009 to the generic bitumen-based royalty regime. This option was initially granted by the government in 1997, but was subject to finalizing certain terms of transition. Should we elect to move our base operations to the bitumen-based royalty in 2009, assuming no change to the current regime, we would expect to pay a royalty in respect of our base operations of 25% of R-C, with "R" based on bitumen rather than upgraded product values, and "C" excluding substantially all of the upgrading costs. We have until late 2008 to decide if we will exercise this option.

In July 2004, we issued a statement of claim against the Crown, seeking, among other things, to overturn the government's decision on the royalty treatment of our Firebag in-situ operations. In February 2006, we advised the Government of Alberta that we had elected not to proceed with our claim relating to the royalty treatment of Firebag.

Assuming anticipated levels of operating expenses and capital expenditures for each project remain relatively constant, and there are no changes to the current Government of Alberta oil sands royalty regime or the government's application of the applicable rules, and no other unanticipated events occur, we believe future variability in Oil Sands royalty expense will primarily be a function of changes in annual Oil Sands revenue. On that basis, we would generally expect Alberta Crown royalty expense for Oil Sands, to range as set forth in the following chart.

If prices rise, we would expect the percentage to increase somewhat. For years after 2008, this percentage range may decline as anticipated new in-situ production attracts royalties based on bitumen values at 1% until project payout and if we elect to exercise the bitumen royalty option referred to in the previous paragraph.

**Anticipated Royalty Expense Based on Certain Assumptions**

For the Period from 2006-2013

| Crown Royalty Expense (based on percentage of total Oil Sands revenue) % | | |
|---|---|---|
| 2006-08 | 10-12 | 12-14 |
| 2009-13 (1) | 5-7 | 6-8 |
| WTI Price/bbl US$ | 40 | 50 |
| Natural gas price per mcf at Henry Hub US$ | 6.50 | 7.50 |
| | | |
| Light/heavy oil differential of WTI at Cushing less Maya at the U.S. Gulf Coast US$ | 9.50 | 10.50 |
| Cdn$/US$ exchange rate | 0.80 | 0.85 |

(1) Assuming we exercise our option to transition our base operations in 2009 to the generic bitumen-based royalty regime.

Based on these same economic assumptions and our current capital spending plans, and assuming continuation of the current economic circumstances including no change to the current Alberta Crown royalty regime for oil sands, we would expect the 25% R-C royalty to apply to our existing Oil Sands base operations in future years and the 1% minimum royalty to apply to the Firebag project until the next decade.

Alberta Crown royalties are highly sensitive to, among other factors, changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each oil sands project. In addition, all aspects of the current Alberta oil sands royalty regime, including royalty rates and the royalty base, are subject to alteration by the Government of Alberta. Accordingly, in light of these uncertainties and the potential for unanticipated events to occur, we strongly caution that it is impossible to predict even a range of annualized royalty expense as a percentage of revenues or the impact royalties may have on our financial results, and actual differences may be material. For example, our Alberta oil sands Crown royalty expense in 2006 and future years may be significantly impacted by the amount of outstanding business interruption insurance proceeds we receive, and the timing of the receipts. Therefore, the forward-looking information in the preceding paragraphs and table should not be taken as an estimate, forecast or prediction of future events or circumstances.

The timing of when the Oil Sands operations will be fully cash taxable is highly dependent on crude oil commodity prices and capital invested. Using the assumptions outlined in the table above, we anticipate that our Oil Sands and NG operations will be partially cash taxable commencing in 2007. These operations will continue to be partially cash taxable until the next decade, at which point they are expected to become fully cash taxable. In any particular year, our 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 income tax purposes.

The information in the preceding paragraphs under Oil Sands Crown Royalties and Cash Income Taxes incorporates operating and capital cost assumptions included in our current budget and long-range plan, and is not an estimate, forecast or prediction of actual future events or circumstances.

***Climate Change***

Our effort to reduce greenhouse gas emissions is reflected in our pursuit of greater internal energy efficiency; investment in renewable energy including wind power; carbon capture research and development; and emissions offsets.

We continue to consult with governments about the impact of the Kyoto Protocol and we 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 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, we do not currently anticipate that the cost implications of federal and provincial climate change plans will have a material impact on our 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 indicated what, if any, limitations will be placed on the price of carbon

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



credits after 2012. It is not possible to predict how these and other Kyoto Protocol-related issues will ultimately be resolved.

**Risk Factors Affecting Performance**

Our 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 Factors for each of our business segments. A more detailed discussion of risk factors is presented in our most recent Annual Information Form/Form 40-F, filed with securities regulatory authorities.

***Commodity Prices, Refined Product Margins and Exchange Rates***

Our 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 2003 to 2005 the monthly average price for benchmark WTI crude oil ranged from a low of US$28.10/bbl to a high of US$65.55/bbl. During the same three-year period, the natural gas Henry Hub benchmark monthly average price ranged from a low of US$4.49/mcf to a high of US$14.07/mcf. We believe commodity price volatility will continue.

Crude oil and natural gas prices are based on U.S. dollar benchmarks that result in our realized prices being influenced by the Cdn$/US$ currency exchange rate, thereby creating an element of uncertainty. 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 our U.S. dollar denominated debt. The opposite would occur should the Canadian dollar weaken compared to the U.S. dollar. Cash flow from operations is not impacted by the effects of currency fluctuations on our 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 debt at the end of 2005, a $0.01 change in the Cdn$/US$ exchange rate would change earnings by approximately $11 million after-tax.

During 2005, the strengthening of the Canadian dollar against the U.S. dollar resulted in a $31 million after-tax foreign exchange gain on our U.S. dollar denominated debt.

Our 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.

**Sensitivity Analysis** (1)

| | 2005 Average | Change | Approximate Change in Cash Flow from Operations ($ millions) | Approximate Change in After-tax Earnings ($ millions) |
|---|---|---|---|---|
| **Oil Sands** | | | | |
| Price of crude oil ($/barrel) (2) | $ 53.81 | US$1.00 | 39 | 25 |
| Sweet/sour differential ($/barrel) | $ 14.55 | US$1.00 | 25 | 16 |
| Sales (bpd) | 165 300 | 1 000 | 12 | 8 |
| **Natural Gas** | | | | |
| Price of natural gas ($/mcf) (2) | $ 8.57 | 0.10 | 5 | 3 |
| Production of natural gas (mmcf/d) | 190 | 10 | 21 | 10 |
| **Energy Marketing and Refining – Canada** | | | | |
| Refining/wholesale margin (cpl) (2) | 7.6 | 0.1 | 5 | 3 |
| **Refining and Marketing – U.S.A.** | | | | |
| Refining/wholesale margin (cpl) | 9.0 | 0.1 | 5 | 3 |
| **Consolidated** | | | | |
| Exchange rate: Cdn$/US | $ 0.83 | 0.01 | 33 | 9 |

(1) The sensitivity analysis shows the main factors affecting Suncor's annual cash flow from operations and earnings based on actual 2005 operations. The table illustrates the potential financial impact of these factors applied to Suncor's 2005 results. A change in any one factor could compound or offset other factors.
(2) Includes the impact of hedging activities.



***Derivative Financial Instruments***

We periodically enter 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. We also periodically enter into derivative financial instrument contracts such as interest rate swaps and foreign currency contracts as part of our risk management strategy to manage exposure to interest rate and foreign exchange fluctuations.

We also use 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 our 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** Our crude oil hedging program has been the subject of periodic management reviews to determine the continued need for hedging in light of our tolerance for exposure to market volatility as well as the need for stable cash flow to finance future growth. In the first quarter of 2004, the Board of Directors suspended the strategic crude oil hedging program. Crude oil hedges in place at the time fixed the price on 36,000 bpd of crude oil at an average price of US$23/bbl for 2005 (79,000 bpd at an average price of US$21 to US$24/bbl in 2004). These contracts expired on December 31, 2005.

To provide an element of stability to future earnings and cash flow, we resumed our strategic crude oil hedging program in the third quarter of 2005, receiving Board approval to permit us to fix a price or range of prices for a percentage of our total production of crude for specified periods of time. At December 31, 2005 we had entered into US$ WTI agreements covering 7,000 bpd of crude oil beginning January 1, 2006 and ending December 31, 2007. Prices for these barrels are fixed within a range of US$50/bbl to an average of approximately US$93/bbl WTI. We have continued to enter into crude oil hedges during the first quarter of 2006. As at March 1, 2006, crude oil hedges totalling 50,000 bpd of production were outstanding for the remainder of 2006 and 2007. Prices for these barrels are fixed within a range of US$50/bbl to an average of US$91.70/bbl. We intend to consider additional costless collars of up to 30% of our crude oil production if strategic opportunities are available.

On settlement of swap agreements, our hedging contracts result in cash receipts or payments for the difference between the derivative contract and market rates for the applicable volumes hedged during the contract term. For collars, if market rates are within the range of the hedged contract prices, the option contracts making up the collar will expire with no exchange of cash. Such cash receipts or payments offset corresponding decreases or increases in our 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 2005, crude oil hedging decreased our net earnings by $337 million compared to a decrease of $397 million in 2004 (2003 – decrease of $155 million).

Crude oil hedge contracts outstanding at December 31, 2005 were as follows:

| | Quantity (bpd) | Average Price (US$ /bbl)(a) | Revenue Hedged (Cdn$ millions)(b) | Hedge Period (c) |
|---|---|---|---|---|
| Costless collars | 7 000 | 50.00 – 92.57 | 149 – 276 | 2006 |
| Costless collars | 7 000 | 50.00 – 92.57 | 149 – 276 | 2007 |

(a) Average price of crude oil costless collars is WTI per barrel at Cushing, Oklahoma.
(b) The revenue hedged is translated to Cdn$ at the year-end exchange rate and is subject to change as the Cdn$/US$ exchange rate fluctuates during the hedge period.
(c) Original hedge term is for the full year.



**Financial Hedging Activities** We periodically enter into interest rate swap contracts as part of our strategy to manage exposure to interest rates. The interest rate swap contracts involve an exchange of floating rate and fixed rate interest payments between ourselves and investment grade counterparties. The differentials on the exchange of periodic interest payments are recognized as an adjustment to interest expense.

We have entered into various interest rate swap transactions at December 31, 2005. 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 | 2005 Effective Interest Rate |
|---|---|---|---|
| Swap of 6.70% Medium Term Notes to floating rates | 200 | 2011 | 4.0% |
| Swap of 6.80% Medium Term Notes to floating rates | 250 | 2007 | 4.6% |
| Swap of 6.10% Medium Term Notes to floating rates | 150 | 2007 | 4.0% |

In 2005, these interest rate swap transactions reduced pretax financing expense by $14 million compared to a pretax reduction of $17 million in 2004 (2003 – $12 million pretax).

At December 31, 2005, we had also hedged a portion of our euro exposure created by the anticipated purchase of equipment for a total of $31 million euros in 2006 and 2007.

**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 we 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) | 2005 | 2004 |
|---|---|---|
| Revenue hedge swaps and collars | **(4)** | (305) |
| Margin hedge swaps | **1** | 5 |
| Interest rate swaps and foreign currency forwards | **22** | 36 |
| | **19** | (264) |

We also use derivative instruments to hedge risks specific to individual transactions. The estimated fair value of these instruments was $5 million at December 31, 2005, compared to $9 million at December 31, 2004.

**Energy Trading Activities** Energy trading activities focus on the commodities we produce. In addition to financial derivatives used for hedging activities, we also use 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 2005, we recorded a net pretax gain of $5 million compared to a pretax gain of $11 million in 2004 (2003 – pretax loss of $3 million) related to the settlement and revaluation of financial energy trading contracts. In 2005, the settlement of physical trading activities resulted in a net pretax gain of $15 million compared to a net pretax gain of $12 million in 2004 (2003 – $2 million net pretax gain). These gains were included as energy marketing and trading activities in the Consolidated Statements of Earnings. Net of related general and administrative costs, the combination of these activities resulted in 2005 net after-tax earnings of $11 million compared to net after-tax earnings of $12 million in 2004 (2003 – $2 million after-tax loss).

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

| ($ millions) | 2005 | 2004 |
|---|---|---|
| Energy trading assets | **82** | 26 |
| Energy trading liabilities | **70** | 9 |
| Net energy trading assets | **12** | 17 |

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

**Counterparty Credit Risk** We may be exposed to certain losses in the event that the counterparties to derivative financial instruments are unable to meet the terms of the contracts. Our exposure is limited to those counterparties holding derivative contracts with net positive fair values at the reporting date. We minimize this risk by entering into agreements primarily with investment grade counterparties. Risk is also minimized through regular management review of the potential exposure to and credit ratings of such counterparties.



At December 31, the company had exposure to credit risk with counterparties as follows:

| ($ millions) | 2005 | 2004 |
|---|---|---|
| Derivative contracts not accounted for as hedges | **82** | 7 |
| Unrecognized derivative contracts accounted for as hedges | **30** | 21 |
| Total | **112** | 28 |

***Environmental Regulations***

Environmental laws affect nearly all aspects of our operations, imposing certain standards and controls on activities relating to oil and gas mining, in-situ 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, we expect 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 our 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 us 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.

We anticipate 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, we 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**

Critical accounting estimates are defined as estimates that are important to the portrayal of our financial position and operations, and require management to make judgments based on underlying assumptions about future events and their effects. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as our operating environment changes. Critical accounting estimates are reviewed annually by the Audit Committee of the Board of Directors. We believe the following are the most critical accounting estimates used in the preparation of our consolidated financial statements.

***Property, Plant and Equipment***

We account for our Oil Sands in-situ and NG exploration and production activities using the "successful efforts" method. This policy was selected over the alternative of the full-cost method because we believe it provides more timely accounting of the success or failure of exploration and

production activities.

The application of the successful efforts method of accounting requires management to determine the proper classification of activities designated as developmental or exploratory, which then 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 ("written off") or partially removed ("written down") in our records and reported as part of Oil Sands and NG DD&A expenses in the Consolidated Statements of Earnings.

Our plant and equipment are depreciated on a straight-line basis over the estimated useful life of the assets. 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 our Oil Sands base operations and our Firebag operations are not based on recorded reserves as we have access to other undeveloped properties, and bitumen feedstock from third parties, as well as the ability to provide processing services for other producers' bitumen. Firebag and NG property costs are depleted on a unit of production (UOP) basis. UOP amortization is used where that method better matches the asset utilization with the production associated with the asset. 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.

We determine 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 our 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 of our 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.

We also continuously look at ways to further utilize technological advancements and opportunities for future growth. The classification of research and development costs as either capital or expense is dependent upon specific criteria, including production feasibility, available resources and management commitment.

***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, removal of which precedes mining of the oil sands deposits.

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 2005, the overburden amortization charge was $178 million (2004 – $225 million; 2003 – $208 million) compared with actual cash overburden spending of $287 million (2004 – $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 Consolidated Balance Sheets.

To ensure that each tonne of oil sands mined is allocated a proportionate share of overburden removal costs, we use 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 is used 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, we have seen our stripping ratios vary, which can increase or decrease the overburden amortization costs charged to the earnings statement. In 2005, the stripping ratio decreased by approximately 10% due to new operational information and mine plan changes. The effects of the decreased stripping ratio were offset by higher per unit overburden removal costs. The $135 million increase in the amount of overburden deferred in 2005 compared to 2004 is therefore primarily due to increased overburden volumes moved (see page 43).

Our existing policy of accounting for overburden may be revised in 2006. Refer to "Recently Issued Canadian Accounting Standards" on page 39.

***Asset Retirement Obligations (ARO)***

We are required to recognize a liability for the future retirement obligations associated with our property, plant and equipment. An ARO is only recognized to the extent there is a legal obligation associated with the retirement of a tangible long-lived asset that we are required to settle as a result of an existing or enacted law, statute, ordinance, 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 our total ARO amount. These individual assumptions can be subject to change based on experience.

The ARO is measured at fair value and discounted to present value using a credit-adjusted risk-free discount rate of 5.6% (2004 – 6%). The ARO accretes over time until we settle the obligation, the effect of which is included in a separate line in the Consolidated Statements of Earnings entitled “Accretion of asset retirement obligations”. 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 is adjusted as 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 2005, we increased our estimated undiscounted total obligation to approximately $1.2 billion from the previous estimate of $1.1 billion. The increase was primarily due to a change in the Oil Sands estimate from $940 million to $1,080 million, primarily reflecting increased estimated costs related to consolidated tailings projects and increased land reclamation and reforestation costs. The majority of the costs in Oil Sands are projected to occur over a time horizon extending to approximately 2060. In 2006, these changes in the ARO estimate are anticipated to result in additional after-tax expenses of approximately $4 million. The discounted amount of our ARO liability was $543 million at December 31, 2005 compared to $476 million at December 31, 2004.

The greatest area of judgment and uncertainty with respect to our asset retirement obligations relates to our Oil Sands mining leases where there is a requirement to provide for land productivity equivalent to pre-disturbed conditions. 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, 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***

We are a Canadian issuer 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”). 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 on page 36).

Pursuant to U.S. disclosure requirements, we also disclose gross and net proved and probable mining reserves. The estimates of our gross and net mining reserves are based in part on the current mine plan and estimates of extraction recovery and upgrading yields. We report mining reserves as barrels of synthetic crude oil based on a net coker, or synthetic crude oil yield from bitumen of 80%. During 2005, we reached an agreement with the Government of Alberta finalizing the terms of our option to transition to the generic bitumen-based royalty regime commencing in 2009, allowing us to prepare an estimate of our net mining reserves. The estimate of our net mining reserves reflects the relative value of Alberta Crown and freehold royalty burdens under constant December 31st bitumen pricing and assumes we will elect to transfer to a bitumen-based Crown royalty effective at the beginning of 2009 (see “Required U.S. Oil and Gas and Mining Disclosure – Proved and Probable Oil Sands Mining Reserves” for both gross and net, proved and probable mining reserves). Our Firebag in-situ leases are subject to Crown royalty based on bitumen, rather than synthetic crude oil (for a full discussion of our Oil Sands Crown royalties, see page 27).

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:

- Gross and net 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%); and

- Gross and net 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 at 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 aggregation purposes only, to barrels of synthetic crude oil based on a net coker or synthetic crude oil yield from bitumen of 80%.

Accordingly, our voluntary disclosures of reserves from our Firebag in-situ leases will differ from our required U.S. disclosure in four ways. Reserves from our Firebag in-situ leases under our voluntary disclosure:

- are disclosed on a gross basis as well as the required net basis under U.S. disclosure requirements;
- are converted from barrels of bitumen under U.S. disclosure requirements to barrels of synthetic crude oil for aggregation purposes only;
- are evaluated based on 2005 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; and
- include proved plus probable reserves, rather than proved reserves only under U.S. disclosure requirements.

Under the U.S. disclosure requirements described above, our Firebag in-situ reserves were determined to be entirely uneconomic at December 31, 2004. In 2005, Constant Cost and Pricing assumptions were again applied to assess economic viability of our in-situ reserves. This assessment resulted in the rebooking of proved reserves at December 31, 2005 (see “Required U.S. Oil and Gas and Mining Disclosure – Proved Conventional Oil and Gas Reserves” on page 36).

Under our voluntary disclosure, using 2005 Annual Average Differential Pricing, our Firebag in-situ reserves were also determined to be economic and accordingly, were disclosed under “Voluntary Oil Sands Reserves Disclosure – Estimated Gross and Net Proved and Probable Oil Sands Reserves Reconciliations”. Comparisons of reserve estimates under “Required U.S. Oil and Gas and Mining Disclosure” and “Voluntary Oil Sands Reserves Disclosure” will show material differences based on the pricing assumptions used, whether the reserves are reported as barrels of bitumen or barrels of synthetic crude oil, whether probable reserves are included, and whether the reserves are reported on a gross or net basis.

All of our reserves have been evaluated as at December 31, 2005 by independent petroleum consultants, GLJ Petroleum Consultants Ltd. (GLJ). In reports dated February 21, 2006 (“GLJ Oil Sands Reports”), GLJ evaluated our proved and probable reserves on our oil sands mining and Firebag in-situ leases, pursuant to both U.S. disclosure requirements using Constant Cost and Pricing assumptions, and pursuant to CSA Staff Notice 51-315, using 2005 Annual Average Differential Pricing assumptions.

Estimates in the GLJ Oil Sands Reports consider recovery from leases for which regulatory applications have been submitted and no anticipated impediment to the receipt of regulatory approval is expected. 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, or likely impediments to the receipt of pending regulatory approval, project implementation commitments, detailed design estimates, detailed reservoir studies, demonstrated commercial success of analogous commercial projects and drill density. Our proved reserves are delineated to within 80-acre spacing with 3D seismic control (or 40-acre spacing without 3D seismic control) while our probable reserves are delineated to within a 320-acre spacing with 3D seismic control (or 160-acre spacing without 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 have not yet received final approval from our Board.

In a report dated February 21, 2006 (“GLJ NG Report”), GLJ also evaluated our 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, 2005.



More information about the evaluation of our reserves by GLJ, as well as additional oil and gas data, is available in our most recent Annual Information Form, which is filed with the United States Securities and Exchange Commission under cover of Form 40-F.

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

Net reserves represent Suncor’s undivided percentage interest in total reserves after deducting Crown Royalties, freehold and overriding royalty interests. Reserve estimates are based on assumptions about pricing, production levels, operating costs and capital expenditures. These assumptions reflect market conditions, as required, at December 31, 2005 which could differ significantly from other points in time throughout the year, or future periods. These market conditions and assumptions can materially impact the estimation of net reserves.

**Required U.S. Oil and Gas and Mining Disclosure**

***Proved and Probable Oil Sands Mining Reserves***

| | Proved | | Probable | | Proved & Probable | |
|---|---|---|---|---|---|---|
| **Millions of barrels of synthetic crude oil (1)** | **Gross (2)** | **Net (3)** | **Gross (2)** | **Net (3)** | **Gross (2)** | **Net (3)** |
| December 31, 2004 | 939 | 916 | 847 | 837 | 1 786 | 1 753 |
| Revisions of previous estimates | 645 | 575 | (439) | (438) | 206 | 137 |
| Extensions and discoveries | — | — | 488 | 463 | 488 | 463 |
| Production | (56) | (51) | — | — | (56) | (51) |
| **December 31, 2005** | **1 528** | **1 440** | **896** | **862** | **2 424** | **2 302** |

(1) Synthetic crude oil reserves are based upon a net coker, or synthetic crude oil yield from bitumen of 80% (2004 – 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) Net mining reserves reflect the relative value of Crown, freehold and overriding royalty burdens under constant December 31st pricing and assumes we will elect to transfer to a bitumen-based Crown royalty effective at the beginning of 2009.

***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 of conventional oil and gas activities only, and therefore our Oil Sands mining activities are excluded, while our Firebag in-situ reserves are included.

**Net Proved Reserves** (1)
***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) (2) (3) (4) | Natural Gas business: crude oil and natural gas liquids (millions of barrels) | Total (millions of barrels) | Natural Gas business: natural gas (billions of cubic feet) |
|---|---|---|---|---|
| December 31, 2004 | —(3) | 8 | 8 | 446 |
| Revisions on previous estimates (5) | 639 | — | 639 | 14 |
| Purchases of minerals in place | — | — | — | — |
| Extensions and discoveries | — | — | — | 40 |
| Production | (7) | (1) | (8) | (50) |
| Sales of minerals in place | — | — | — | (1) |
| **December 31, 2005** | **632** | **7** | **639** | **449** |

(1) Our undivided percentage interest in reserves, after deducting Crown royalties, freehold royalties and overriding royalty interests. Our Firebag leases are only subject to Crown royalties.
(2) Although we are subject to Canadian disclosure rules in connection with the reporting of our reserves, we have received exemptive relief from Canadian securities administrators permitting us to report our proved reserves in accordance with U.S. disclosure practices.
(3) Estimates of proved reserves from our Firebag in-situ leases are based on Constant Costs 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. Under 2005 Constant Cost and Pricing assumptions, we have rebooked our proved reserves.
(4) We have the option of selling the bitumen production from these leases or upgrading the bitumen to synthetic crude oil. With the completion of upgrading expansion projects during 2005, all bitumen is expected to be processed into synthetic crude oil in the future.
(5) Includes total infill drilling of 23 billion cubic feet (bcf) in 2005.



**Voluntary Oil Sands Reserves Disclosure**

***Oil Sands Mining and Firebag***

***In-situ Reserves Reconciliation***

The following tables set out, on a gross and net basis, a reconciliation of our proved and probable reserves of synthetic crude oil from our Oil Sands mining leases and bitumen (converted to synthetic crude oil for comparison purposes only) from our Firebag in-situ leases, from December 31, 2004 to December 31, 2005, based on the GLJ Oil Sands Reports, in accordance with CSA Staff Notice 51-315, using 2005 Annual Average Differential Pricing assumptions.

**Estimated Gross Proved and Probable Oil Sands Reserves Reconciliation**

| | Oil Sands Mining Leases (1) (2) | | | Firebag In-situ Leases (1) (3) | | | Total Mining and In-situ (3) |
|---|---|---|---|---|---|---|---|
| Millions of barrels of synthetic crude oil (1) | Proved | Probable | Proved & Probable | Proved | Probable | Proved & Probable | Proved & Probable |
| December 31, 2004 | 939 | 847 | 1 786 | 494 | 1 900 | 2 394 | 4 180 |
| Revisions of previous estimates | 645 | (439) | 206 | 73 | (131) | (58) | 148 |
| Improved Recovery | — | — | — | — | 368 | 368 | 368 |
| Extensions and discoveries | — | 488 | 488 | — | — | — | 488 |
| Production | (56) | — | (56) | (6) | — | (6) | (62) |
| **December 31, 2005** | **1 528** | **896** | **2 424** | **561** | **2 137** | **2 698** | **5 122** |

**Estimated Net Proved and Probable Oil Sands Reserves Reconciliation**

| | Oil Sands Mining Leases (1) (2) | | | Firebag In-situ Leases (1) (3) | | | Total Mining and In-situ (3) |
|---|---|---|---|---|---|---|---|
| Millions of barrels of synthetic crude oil (1) | Proved | Probable | Proved & Probable | Proved | Probable | Proved & Probable | Proved & Probable |
| December 31, 2004 | 916 | 837 | 1 753 | 457 | 1 714 | 2 171 | 3 924 |
| Revisions of previous estimates | 575 | (438) | 137 | 105 | (38) | 67 | 204 |
| Improved Recovery | — | — | — | — | 353 | 353 | 353 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Extensions and discoveries | — | 463 | 463 | — | — | — | 463 |
| Production | (51) | — | (51) | (6) | — | (6) | (57) |
| **December 31, 2005** | **1 440** | **862** | **2 302** | **556** | **2 029** | **2 585** | **4 887** |

(1) Synthetic crude oil reserves are based on a net coker, or synthetic crude oil yield from bitumen of 80% for reserves under Oil Sands Mining and 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 into synthetic crude oil. Accordingly, these bitumen reserves are converted to synthetic crude oil for aggregation 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. Net mining reserves reflect the relative value of Crown, freehold and overriding royalty burdens under constant December 31st pricing and assumes we will elect to transfer to a bitumen-based Crown royalty effective at the beginning of 2009.

(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 four ways. Reserves from our Firebag in-situ leases under our voluntary disclosure:

(a) are disclosed on a gross basis as well as the required net basis under required U.S. disclosure requirements;
(b) are converted from barrels of bitumen to barrels of synthetic crude oil in this table for aggregation purposes only;
(c) are 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; and
(d) include proved plus probable reserves, rather than proved reserves only under U.S. disclosure requirements. U.S. companies do not disclose probable reserves for non-mining properties. We voluntarily disclose our probable reserves for our 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 in the above tables are not comparable to those made by U.S. companies.

***Employee Future Benefits***

We provide a range of benefits to our employees and retired employees, including pensions and other post-retirement health care and life insurance benefits. The determination of obligations under our 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 our 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.

| | 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 | (15) | 17 | 7 | (7) |
| Increase (decrease) to benefit obligation | — | — | (119) | 140 | 35 | (33) |

Health care costs comprise a significant element of our post-employment benefit obligation and is an area where there is increasing cost pressure due to an aging North American population. We have assumed a 10% annual rate of increase in the per capita cost of covered health care benefits for 2005, with an assumption that this rate will decrease by 0.5% annually, to 5% by 2015, 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 | 1 | (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, 2005, our Chief Executive Officer and Chief Financial Officer concluded that our 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 us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms. In addition, other than as described below, as of December 31, 2005, there were no changes in our internal control over financial reporting that occurred during 2005 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We will continue to periodically evaluate our disclosure controls and procedures and internal control over financial reporting and will make any modifications from time to time as deemed necessary.

We are in the process of implementing an enterprise resource planning (ERP) system in all of our businesses to facilitate our growth plan. The phased implementation is currently planned to be complete by the end of 2006. Implementing an ERP system on a widespread basis involves significant changes in business processes and extensive organizational training. We currently believe a phased-in approach reduces the risks associated with making these changes. We believe we are taking the necessary steps to monitor and maintain appropriate internal control over financial reporting during this transition period. These steps include deploying resources to mitigate internal control risks and performing additional verifications and testing to ensure data integrity.

In connection with the continued implementation of our ERP system, we expect there will be a significant redesign of our business processes during 2006, some of which relate to internal control over financial reporting and disclosure controls and procedures.



**Change In Accounting Policies**

***Preferred Securities***

On January 1, 2005, we retroactively adopted the Canadian accounting standard related to disclosure and presentation of financial instruments. Accordingly, our preferred securities, which were redeemed in March 2004, have been reclassified as long-term debt and the preferred dividends have been reclassified as financing expense. We have restated our property, plant and equipment and depreciation, depletion and amortization to reflect capitalized interest that would have been incurred and amortized had the preferred securities been classified as debt during the period in which they were outstanding. The impact of adopting this standard was an increase to property, plant and equipment of $37 million.

***Consolidation of Variable Interest Entities***

On January 1, 2005, we prospectively adopted Canadian Accounting Guideline 15 – “Consolidation of Variable Interest Entities” (VIE’s). Accordingly, we consolidated the VIE related to the sale of equipment as described on page 26. The impact of adopting this standard was an increase to property, plant and equipment of $14 million, an increase to materials and supplies inventory of $8 million and an increase to long-term debt of $22 million. There was no impact to net earnings.

**Recently Issued Canadian Accounting Standards**

***Non-monetary Transactions***

In 2005, the Canadian Institute of Chartered Accountants (CICA) approved Handbook Section 3831 “Non-Monetary Transactions”. Effective January 1, 2006, all non-monetary transactions must be measured at fair value (if determinable) unless the transaction lacks commercial substance, is an exchange of a product held for sale in the ordinary course of business, or is a product to be sold in the same line of business. Commercial substance exists when the company’s future cash flows are expected to change significantly as a result of a transaction. We will be required to record the effects of an existing contract at Oil Sands that exchanges off-gas produced as a by-product of the upgrading operations for natural gas. An equal amount of revenues for the sale of the off-gas and purchases of crude oil and products for the purchase of natural gas will be recorded. The amount of the gross-up will be dependent on the prevailing prices for natural gas. Currently this transaction is recorded on a net basis in purchases of crude oil and products. Retroactive adjustment is prohibited by the standard.

***Overburden Removal Costs***

On February 16, 2006, the Emerging Issues Committee of the CICA approved an abstract regarding the treatment of overburden costs in the mining industry effective July 1, 2006. The proposed abstract would require the capitalization of overburden removal costs when such costs represent a betterment to the mine property by facilitating access to reserves in future periods. Costs are to be treated as variable production costs and expensed as incurred when no betterment exists. We currently amortize the cost of overburden removal using stripping ratios based on a life of mine approach. We are considering expensing overburden costs as incurred on a retroactive basis effective from January 1, 2006. With the exception of the impact on 2005 net earnings, the effect of adopting the standard is not expected to be significant. Net earnings in 2005 would be reduced by approximately $87 million due to increased amounts of overburden moved during the year.

***Financial Instruments/Other Comprehensive Income/Hedges***

In 2005, the CICA approved Handbook Section 3855 “Financial Instruments – Recognition and Measurement”; Section 1530 – “Comprehensive Income” and Section 3865 “Hedges”. Effective January 1, 2007, these standards require the presentation of financial instruments at fair value on the balance sheet.

For specific transactions identified as hedges, changes in fair value are recognized in net earnings or other comprehensive income based on the type and effectiveness of the individual instruments. Upon adoption, our presentation will be aligned with the current U.S. GAAP reporting as outlined in note 18 to our Consolidated Financial Statements.

Other comprehensive income will represent the foreign currency translation of self-sustaining subsidiaries, the fair value gains/losses of specific financial investments (available for sale) and the effective portion of gains/losses of cash flow hedges. Presentation of other comprehensive income will require a change in the presentation of the Consolidated Statements of Earnings.

**OIL SANDS**

Located near Fort McMurray, Alberta, our Oil Sands business forms the foundation of our growth strategy and represents the most significant portion of our assets. The Oil Sands business recovers bitumen through mining and in-situ development and upgrades it into refinery feedstock, diesel fuel and byproducts. Our marketing plan also calls for sales of bitumen when production from mining and in-situ operations exceed upgrading capacity, assuming market conditions are favourable.

Oil Sands strategy focuses on:

- Acquiring long-life 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.
- Pursuing new technology applications to increase production, reduce costs and reduce environmental impacts.

**HIGHLIGHTS**

**Summary of Results**

| **($ millions unless otherwise noted)**<br>**Year ended December 31** | **2005** | **2004** | **2003** |
|---|---|---|---|
| Revenue | **3 965** | 3 640 | 3 101 |
| Production (thousands of bpd) | **171.3** | 226.5 | 216.6 |
| Average sales price ($/barrel) | **53.81** | 42.28 | 37.19 |
| Net earnings | **1 073** | 994 | 887 |
| Cash flow from operations | **1 895** | 1 752 | 1 803 |
| Total assets | **11 850** | 9 067 | 7 970 |
| Cash used in investing activities | **1 929** | 1 087 | 1 060 |
| Net cash surplus (deficiency) | **(257)** | 737 | 799 |
| ROCE (%) (1) | **24.3** | 22.9 | 20.8 |
| ROCE (%) (2) | **17.6** | 18.8 | 17.4 |

(1) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for our operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non GAAP Financial Measures. See Page 56.
(2) Includes capitalized costs related to major projects in progress.See page 56.

**2005 Overview**

- In September 2005, we completed rebuilding portions of our Oil Sands plant that were damaged by fire on January 4, 2005. The recovery and planned maintenance work was completed on schedule and the plant was running at full capacity by the end of September.

- In October, we successfully commissioned an expansion of our Oil Sands facilities by adding a vacuum unit to Upgrader 2, increasing our capacity to 260,000 barrels per day (bpd) from 225,000 bpd. Construction was completed on schedule and on budget. See page 26.

- Our Firebag Stage 2 in-situ project entered the start-up phase, with first oil in the fourth quarter of 2005. Commercial operations are expected to commence in the first quarter of 2006. See page 26.

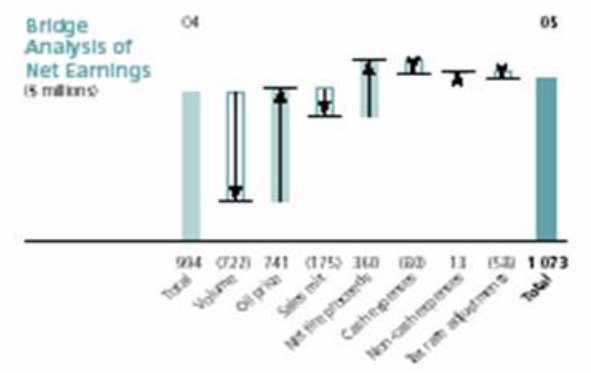


- Construction continued on the estimated $2.1 billion project that, when complete in 2008, is expected to increase upgrading capacity to 350,000 bpd. The centrepiece of this expansion is the addition of a third pair of cokers to Upgrader 2. Fabrication and placement of the coke drums is complete, and the project remains on schedule and within budget projections. See page 26.

- An application was filed with Alberta regulators to construct and operate a third Oil Sands upgrader, designed to increase our production capacity to 500,000 to 550,000 bpd by 2012. We also filed an application with Alberta regulators requesting permission to proceed with the Steepbank mine extension.

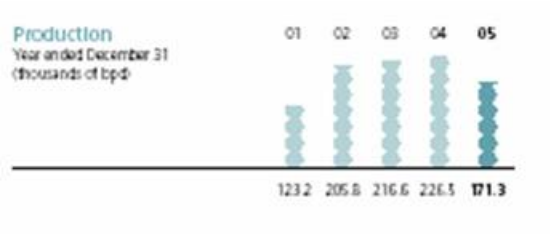
**Analysis of Net Earnings**

Net earnings were $1,073 million in 2005 compared to $994 million in 2004 (2003 – $887 million). The increase in net earnings was due primarily to high price realizations on the Oil Sands basket of products, reflecting higher benchmark WTI prices, the receipt of fire insurance proceeds and lower hedging losses. These positive factors were largely offset by widening light/heavy crude oil differentials, decreased production and sales volumes and a decrease in the sales mix of sweet crude oil and diesel fuel compared to sour crude oil and bitumen as a result of the fire.




Oil Sands average production was 171,300 bpd in 2005, compared to 226,500 bpd in 2004. Sales volumes in 2005 averaged 165,300 bpd compared with 226,300 bpd in 2004. Lower sales volumes decreased 2005 net earnings by $722 million. The decrease in 2005 production and sales volumes was due largely to the effects of the January 4, 2005 fire that reduced production to an average of 122,000 bpd for the first nine months of the year. The build in inventory volumes during 2005 was primarily due to the expanded storage and production facilities that came online during the fourth quarter of 2005.

Sales volumes of higher value diesel fuel and sweet crude products decreased to 54% of total sales volumes in 2005 from 63% in 2004, reflecting the negative impact of the fire, increased bitumen sales from our in-situ operations and the start up of the vacuum unit expansion project. Starting in mid October 2005, all bitumen produced from our Firebag operations was upgraded. Prior to that, bitumen from Firebag was sold directly into the marketplace. The decrease in sweet products as a percentage of our total sales volumes decreased earnings by $175 million. As a result of the new vacuum unit, we anticipate that our sales mix of high value diesel fuel and sweet crude products in 2006 will be 56%(1) of our total sales volumes.




(1) We continue to gain experience in operating facilities that were newly commissioned in late 2005, therefore is more uncertainty in 2006 plans than in prior years.



Sales price realizations averaged $53.81 per barrel in 2005 (including the impact of pretax hedging losses of $535 million) compared with $42.28 per barrel in 2004 (including the impact of pretax hedging losses of $620 million). The average sales price realization was favourably impacted by stronger WTI benchmark crude oil prices as well as higher positive differentials for synthetic sweet crude oil and diesel fuel. These factors were partially offset by wider differentials on sour crude oil and bitumen blends, as well as the continued strengthening of the Canadian dollar compared to the U.S. dollar. As 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 impact of the above pricing factors increased net earnings by $741 million in 2005.

***Net Fire Proceeds***

In 2005, we recognized $572 million in insurance proceeds, net of the write-off of damaged assets and related expenses. During 2005, we received $115 million (US$95 million) from our property loss policy and $594 million (US$500 million) in proceeds from our BI policies, including $175 million (US$150 million)received in January and February 2006. Net fire proceeds increased net earnings by $360 million. For further discussion of our insurance policies, see page 24.

***Cash Expenses***

Cash expenses increased to $1,325 million from $1,191 million in 2004 (2003 – $1,053 million). Expenses were higher year-over-year due to the following factors:

- Higher natural gas costs of approximately $110 million reflecting higher natural gas prices and increased gas consumption at our in-situ operations.

- Higher maintenance costs related to the upgrader that was not damaged by the fire to ensure reliability.

- Higher production volumes at our in-situ operations. This increased cash expenses by approximately $30 million reflecting increased staffing and maintenance. In addition, 2005 was the first full year of in-situ operations. In-situ costs incurred during the first quarter of 2004 were treated as project start-up costs.

Partially offsetting these negative factors:

- Purchases of crude oil and products decreased to $32 million in 2005 from $75 million in 2004. Purchases in 2004 included the repurchase of crude oil originally sold to a VIE in 1999.

- Taxes other than income taxes decreased by $21 million as a result of lower diesel fuel excise taxes reflecting lower sales volumes as a result of the fire.

- We were able to redeploy some of our mining resources to overburden removal as a result of the fire. Despite decreased production volumes, mining expenses decreased only slightly as the increased deferral of overburden costs were almost entirely offset by increased costs associated with mine maintenance projects.

Overall, increased cash expenses reduced net earnings by $80 million.

***Royalties***

Oil Sands Alberta Crown royalties were relatively unchanged at $406 million in 2005 compared to $407 million in 2004 (2003 – $33 million). Alberta Oil Sands Crown royalties are subject to change as policies arising from the government's position are finalized and audits of 2005 and prior years are completed. Changes to the estimated amounts previously recorded will be reflected in our financial statements on a prospective basis and may be significant. 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 our 2004 Alberta Crown royalty obligation. No such carry forward of allowed costs existed for 2005 or subsequent years. For a further discussion on Crown royalties, see page 27.

***Non-cash Expenses***

Non-cash depreciation, depletion and amortization (DD&A) expense, including overburden amortization expense, decreased to $482 million from $505 million in 2004 (2003 – $459 million). The decrease was primarily due to lower overburden amortization of $47 million reflecting lower production volumes, partially offset by higher DD&A expenses from in-situ operations of $13 million. Lower non-cash expenses increased net earnings by $13 million.



Deferred overburden costs are amortized using stripping ratios that allocate the overburden costs to the tonnes of ore mined during the year. In 2005, Oil Sands average overburden removal stripping ratio was 0.47 cubic metres of overburden for every tonne of ore mined, compared to 0.52 cubic metres per tonne in 2004. The decreased stripping ratio year-over-year was primarily due to updated drilling results that provided more detailed information on proved reserves. Overburden amortization decreased to $178 million in 2005 compared with $225 million in 2004, primarily reflecting lower production volumes.

As a result of new Canadian and U.S. GAAP requirements, we are considering expensing overburden costs as incurred. See page 39.

***Tax Adjustments***

In 2004, non-cash income tax expense was reduced by $53 million relating to reductions in the Alberta provincial tax rate. Excluding the 2004 rate change, the remaining tax rate adjustment was due to a small change in the effective tax rate in 2005 compared to 2004 and other minor differences.

***Cash Operating Costs***

In 2005, we reported cash operating costs for upgraded production (base operations) as well as cash costs from in-situ operations. Cash operating costs for base operations increased to $1,123 million ($19.50 per barrel) in 2005 compared to $949 million ($11.95 per barrel) in 2004, primarily due to the same factors affecting cash expenses discussed previously. In addition, per barrel cash costs have increased due to the effect of the fire on production volumes.

Natural gas purchases for base operations averaged approximately 66 million cubic feet per day (mmcf/d) in 2005, consistent with the prior year. Oil Sands natural gas costs increased to $8.95 per mcf in 2005 from $6.74 per mcf in 2004, increasing cash costs by approximately $1.75 per barrel.

**Net Cash Surplus (Deficiency) Analysis**

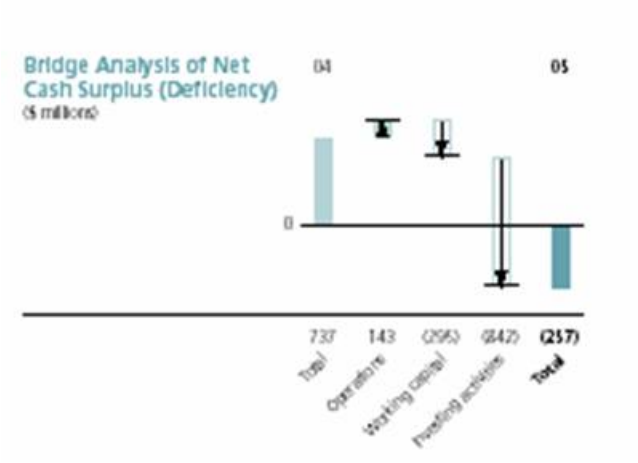
Cash flow from operations was $1,895 million in 2005 compared to $1,752 million in 2004 (2003 – $1,803 million). Excluding the impact of non-cash income tax adjustments, the increase was due to the same factors that increased net earnings, offset by higher cash overburden and reclamation spending, and higher pension funding requirements.

Net working capital increased by $223 million in 2005 compared to a decrease of $72 million in 2004 (2003 – $56 million). Higher accounts receivable due to higher sales volumes and higher price realizations in the final month of 2005 compared to 2004 were only partially offset by increased accounts payable and accrued liabilities related to increased capital spending in 2005.

Cash flow used in investing activities increased to $1,929 million in 2005 from $1,087 million in 2004 (2003 – $1,060 million). During 2005, capital spending related primarily to the reconstruction of assets damaged by the fire, higher sustaining capital for extraction projects, construction of

Firebag Stage 2, the Millennium vacuum unit, engineering and preliminary construction of the Millennium Coker Unit and the debottlenecking of our Steepbank extraction assets.

Combined, the above factors resulted in a net cash deficiency of $257 million in 2005, compared with a surplus of $737 million in 2004 (2003 – $799 million surplus).






**Outlook**

Our Oil Sands operations continue to be the focus of our business strategy. In 2006, we anticipate our oil sands production will average 260,000 bpd from our existing upgrading assets. Our future plans for Oil Sands remain focused on activities and investments anticipated to increase production, identify cost improvements and improve environment, health and safety performance.

For 2006, we have budgeted capital spending of approximately $2.5 billion, of which $700 million is slated for sustaining projects with the remainder earmarked for growth. This growth spending supports the goal of increasing production to 350,000 bpd in 2008, while laying the groundwork for further expansion later in the decade.

***Expansion to 350,000 bpd***

Work to increase production capacity to 350,000 bpd in 2008 is proceeding on schedule. During 2006, construction is planned to continue on the coker unit project, the second stage of our Firebag in-situ project will move into commercial operations and we intend to continue construction on the recently approved cogeneration facility that will provide additional steam and capacity to our in-situ operations. For an update on the progress of these significant capital projects, see page 26.

In addition to the on-going expansion of our proprietary sources of 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, 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 are for a minimum 10-year term.

***Expansion to 500,000 bpd to 550,000 bpd***

In planning for expansion beyond 2008, we filed regulatory applications in 2005 to construct a third upgrader, a key step to increasing production capacity to 500,000 to 550,000 bpd in the 2010 to 2012 time frame. The preliminary cost estimate for this project of $5.9billion (1) is subject to change. This estimate does not include costs for related bitumen supply projects to feed the upgrader. Approval by regulators and Suncor's Board of Directors is required before the project can proceed.

***Mine Extension***

In March 2005, we filed an application for approval to construct and operate an extension of our 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, and are subject to change. Approval by regulators and our Board of Directors is required before construction can proceed.

In 2005, Oil Sands filed a renewal application with regulators for a 10-year renewal of our operating licence.

(1) This cost estimate has a range of uncertainty of +50/–30%. For a discussion of this estimation process see page 26.



**Risk Factors Affecting Performance**

There are certain issues we strive to manage that may affect performance including, but 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 in connection with the January 2005 fire.
- Our ability to finance Oil Sands growth in a volatile commodity pricing environment. Also refer to “Liquidity and Capital Resources” on page 24.
- Our 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 (including housing, roads and schools), or higher prices for the products and services required to operate and maintain the operations. We continue 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. Our strategy is to reduce the impact of this issue by entering into long-term supply agreements with major customers, expanding our customer base and offering a variety of blends of refinery feedstock to meet customer specifications.
- Volatility in crude oil and natural gas prices, foreign exchange rates and the light/heavy and sweet/sour crude oil differentials. These factors are difficult to predict and impossible to control.
- Logistical constraints and variability in market demand, which can impact crude movements. These factors can be difficult to predict and control.
- Our relationship with our 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 58 under Forward-looking Statements. Also refer to Suncor Overview, Risk Factors Affecting Performance on page 29.



## NATURAL GAS

Our Natural Gas (NG) business primarily produces conventional natural gas in Western Canada. NG’s production serves as a price hedge that provides us with a degree of protection from volatile market prices of natural gas purchased for internal consumption in our Oil Sands and downstream operations.

NG’s strategy focuses on:

- Building competitive operating areas.
- Improving base business efficiency.
- Developing new, low-capital business opportunities.

NG’s long-term goal is to achieve a sustainable return on capital employed (ROCE) (1) of 12%-15% at mid-cycle prices of US$5.00 to US$5.50 per thousand cubic feet (mcf). To offset 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) | 2005 | 2004 | 2003 |
|---|---|---|---|
| Revenue | **679** | 567 | 512 |
| Natural gas production (mmcf/d) | **190** | 200 | 187 |
| Average natural gas sales price ($/mcf) | **8.57** | 6.70 | 6.42 |
| Net earnings | **155** | 115 | 120 |
| Cash flow from operations | **412** | 319 | 298 |
| Total assets | **1 307** | 967 | 765 |
| Cash used in investing activities | **344** | 251 | 167 |
| Net cash surplus | **63** | 67 | 143 |
| ROCE (%) (1) | **30.7** | 27.1 | 29.2 |

(1) ROCE for Suncor operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non GAAP Financial Measures. See page 56.

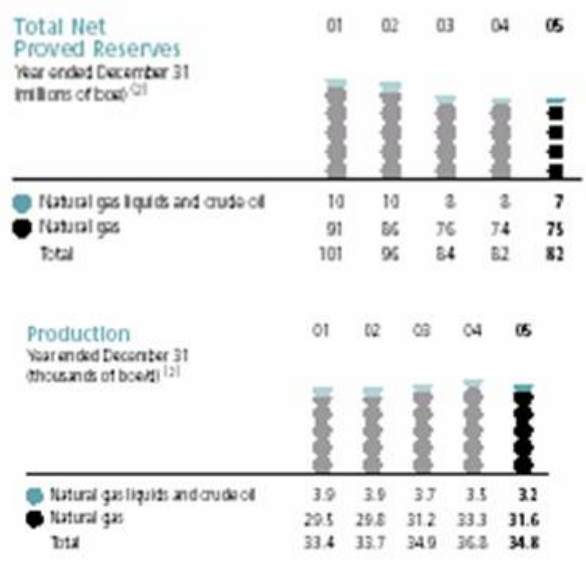
#### 2005 Overview

- Production averaged 190 million cubic feet per day (mmcf/d) in 2005 compared to 200 mmcf/d in 2004 and company-wide purchases for internal consumption of approximately 138 mmcf/d. Production targets for 2005 were negatively impacted by unplanned maintenance and weather related drilling delays that affected the western upstream oil and gas Canadian industry.

- In 2005, construction of the North Cabin Pipeline that connects the Cabin Creek and Solomon fields in the Alberta Foothills to the Simonette gas plant was completed. In addition an expansion and maintenance shutdown at the Simonette gas plant was completed.

- During 2005 we continued the divestment of non-core properties with proceeds of $21 million received in 2005.

- Subsequent to year-end, we disposed of 15% of our interest in the South Rosevear gas plant for proceeds of $12 million. We currently retain a 60.4% interest and continue to operate the gas plant.




(2) For details on barrels of oil equivalent (boe), see page 17.

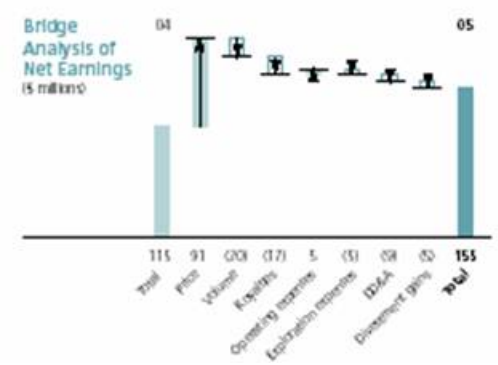


***Analysis of Net Earnings***

NG net earnings were $155 million in 2005, compared to $115 million in 2004 (2003 – $120 million). Higher realized natural gas and liquids prices were partially offset by lower sales volumes, higher royalty expenses, higher depreciation, depletion and amortization (DD&A), higher lifting costs, higher exploration expenses and lower divestment gains. Earnings in 2004 were negatively impacted by costs associated with the final arbitrated settlement of terminated gas marketing contracts related to Enron Corporation's bankruptcy in December 2001.

In 2005, the average realized price for natural gas was $8.57 per mcf, compared to an average of $6.70 per mcf in 2004, reflecting higher benchmark natural gas prices. Price realizations for NG's crude oil and natural gas liquids production were also higher in 2005 due to higher benchmark crude oil prices. The combined impact of the above pricing factors increased net earnings in 2005 by $91 million.

NG's average natural gas production was 190 mmcf/d in 2005 compared to 200 mmcf/d in 2004. Including liquids, total 2005 production was 34,800 boe/d compared to 36,800 boe/d in 2004. The decrease in 2005 production was primarily due to unplanned maintenance issues and weather related delays in drilling during the first half of the year. Lower production volumes negatively impacted 2005 net earnings by $20 million.




***Expenses***

Royalties on NG production were $149 million ($11.72 per boe) in 2005, compared to $124 million ($9.22 per boe) in 2004 (2003 – $106 million; $8.32/boe). The increase was due to higher sales price realizations, caused by higher benchmark commodity prices, partially offset by lower production.

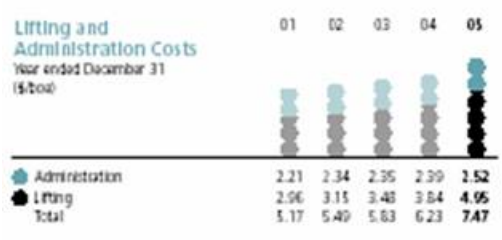
Operating costs were $93 million in 2005 compared to $100 million in 2004 (2003 – $73 million). Total operating costs were higher in 2004 due to an arbitrated settlement of terminated gas marketing contracts related to Enron Corporation's bankruptcy in December 2001 that reduced 2004 after-tax earnings by $12 million. Excluding the Enron settlement, operating costs were higher in 2005 due to higher lifting costs as a result of higher planned and unplanned maintenance.

Exploration expenses increased to $46 million in 2005 from $38 million in 2004 (2003 – $40 million). Higher dry hole expenses were only partially offset by lower seismic expenditures.

DD&A expense was $130 million in 2005 compared to $115 million in 2004 (2003 – $91 million). The increase was due to a higher cost base subject to depletion and a lower proved reserve base, as well as higher amortization expense related to unproven lands.

Divestment gains were $12 million in 2005 ($8 million after-tax) compared to $19 million ($13 million after-tax) in 2004 (2003 – $12 million; $8 million after-tax). Divestments in 2005 reflect sales of non-core properties, whereas 2004 divestments primarily relate to the sale of a 62.5% interest in our Simonette gas plant for proceeds of $19 million.

In total, the above noted items reduced net earnings by $31 million.






**Net Cash Surplus Analysis**

NG's net cash surplus was $63 million in 2005 compared with $67 million in 2004 (2003 – $143 million). Cash flow from operations increased to $412 million compared with $319 million in the prior year (2003 – $298 million), largely due to higher commodity prices, partially offset by lower production and higher royalties.

Cash used in investing activities increased to $344 million compared with $251 million in 2004 (2003 – $167 million) as a result of higher drilling, exploration and facilities costs.

**Outlook**

NG plans to increase natural gas production to 205 to 210 mmcf/d in 2006 to offset our growing internal natural gas demands.

NG intends to continue to leverage its expertise and existing assets to bring reserves into production in Western Canada. However, increasing production may require expansion through farm-ins (1), joint ventures or additional property acquisitions, which could expand the size and number of operating areas, or involve new operating areas outside of Western Canada.

To support these goals, we have budgeted $325 million in capital spending for exploration and development in 2006.




**Risk Factors Affecting Performance**

There are certain issues that we strive to manage that may affect performance of the NG business including, but 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 influence 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 with our indirectly wholly owned subsidiary in the United States. These risks could add to costs or cause delays to projects.
- Risks and uncertainties associated with weather conditions, which can shorten the winter drilling season and impact the spring and summer drilling program, with increased costs or reduced production.
- The impact of market demand for labour and equipment, which in a heated exploration and development market could add to cost or cause delays to projects for NG and its competitors.

These factors and estimates are subject to certain risks, assumptions and uncertainties discussed on page 58 under Forward-looking Statements. Refer to the Suncor Overview, Risk Factors Affecting Performance on page 29.

(1) Acquisition 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 metre per day) capacity refinery in Sarnia, Ontario and markets refined products to industrial, wholesale and commercial customers primarily in Ontario and Quebec. Through our Sunoco-branded and joint venture operated service networks, we market products to retail customers in Ontario. The EM&R 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.
- 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.
- Increasing the profitability and efficiency of retail networks.

As a marketing channel for our refined products, EM&R's Ontario retail network generated approximately 57% of EM&R's total 2005 sales volume of 96,000 bpd. The retail networks are comprised of 275 Sunoco-branded retail service stations, 28 Sunoco-branded Fleet Fuel Cardlock sites, and two 50% retail joint venture businesses (1) that operate 149 Pioneer-branded retail service stations, 50 UPI-branded retail service stations and 14 UPI bulk distribution facilities for rural and farm fuels. Approximately 39% of EM&R's refined product sales in 2005 were wholesale and industrial sales. Sun Petrochemicals Company (SPC), a 50% joint venture between a Suncor subsidiary and a Toledo, Ohio-based refinery, generated the remaining 4% of sales.

(1) Pioneer Group Inc., is an independent company with which we have a 50% joint venture partnership. UPI Inc. is a 50% joint venture with GROWMARK Inc., a Midwest U.S. retail farm supply and grain marketing cooperative.

**HIGHLIGHTS**

**Summary of Results**

| Year ended December 31 | 2005 | 2004 | 2003 |
|---|---|---|---|
| **($ millions unless otherwise noted)** | | | |
| Revenue | **4 299** | 3 460 | 2 936 |
| Refined product sales | | | |
| (millions of litres) | | | |
| Sunoco retail gasoline | **1 656** | 1 665 | 1 599 |
| Total | **5 570** | 5 643 | 5 477 |
| Net earnings (loss) breakdown: | | | |
| Total earnings excluding energy, marketing and trading activities | **30** | 68 | 67 |
| Energy marketing and trading activities | **11** | 12 | (2) |
| Tax adjustments | **—** | — | (12) |
| Total net earnings | **41** | 80 | 53 |
| Cash flow from operations | **152** | 188 | 164 |
| Cash used in investing activities | **436** | 259 | 135 |
| Net cash surplus (deficiency) | **(328)** | (21) | 29 |
| ROCE (%) (1) | **8.1** | 14.6 | 10.3 |
| ROCE (%) (2) | **5.2** | 13.6 | 10.3 |

(1) Excludes capitalized costs related to major projects in progress. Return on capital employed (ROCE) for our operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non GAAP Financial Measures. See Page 56.
(2) Includes capitalized costs related to major projects in progress. See page 56.



**2005 Overview**

- During 2005, construction continued on the diesel desulphurization unit at the Sarnia refinery. This project is intended to meet federal low-sulphur diesel fuel regulations that take effect in 2006. The project, estimated to cost $800 million, is also expected to enable the refinery to process approximately 40,000 bpd of Oil Sands sour crude blends in 2007. See page 26.

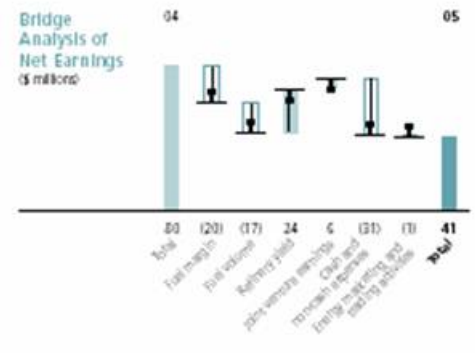
- In April 2005, we received final environmental approvals from federal and provincial governments for our ethanol production facility in the Sarnia region. Construction of the $120 million plant began in June 2005 and is expected to be completed in June 2006. Natural Resources Canada has contributed $19 million towards this project through their Ethanol Expansion Program.

- During March and April 2005, we completed a 24-day planned maintenance shutdown at our Sarnia refinery.

**Analysis of Net Earnings**

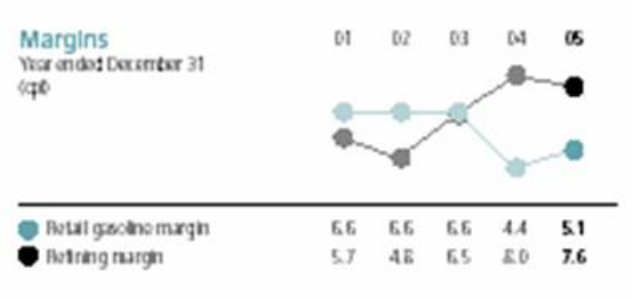
EM&R results include the impact of our third party energy marketing and trading activities that are discussed separately on page 51.

EM&R's net earnings decreased to $41 million in 2005 from $80 million in 2004 (2003 – $53 million). This decrease was primarily due to lower refining margins, lower sales volumes, lower refinery utilization, lower mark-to-market gains on inventory related derivatives, and higher cash refinery operating costs, primarily due to higher energy costs as a result of high natural gas prices. These negative impacts were partially offset by lower third party refined product purchase volumes and higher joint venture earnings.




**Margins**

After-tax refined product margins decreased by $20 million in 2005 compared to 2004, due to lower refining margins on gasoline, chemicals, and other products such as fuel oil and propane, partially offset by increased refining margins in diesel and jet fuel. Refining margins on proprietary refined products averaged 7.6 cents per litre (cpl) in 2005, compared to 8.0 cpl in 2004. Sunoco-branded retail gasoline margins averaged 5.1 cpl in 2005, compared with 4.4 cpl in 2004. The increase was primarily due to an improved competitive pricing environment in the greater Toronto area and tight refined product supply due to hurricanes on the U.S. Gulf Coast during the summer of 2005.




**Volumes**

Total sales volumes averaged 96,000 bpd (15,200 cubic metres per day) in 2005, down slightly from 97,000 bpd (15,400 cubic metres per day) in 2004, resulting in a decrease in net earnings of $17 million. Higher sales volumes of heavy fuel oils and diesel were more than offset by lower sales volumes of gasoline and propane. Total gasoline sales volumes in the Sunoco-branded retail network decreased to 1,656 million litres in 2005 from 1,665 million litres in 2004. Average Sunoco-branded service station site throughput was 6.3 million litres per site in 2005 compared to 6.2 million litres per site in 2004. 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% in 2005 (2004 – 19%). Approximately 96% of EM&R's refined products were sold to the Ontario market in 2005.

**Refinery Utilization**

Overall refinery utilization averaged 95% in 2005, compared with 100% in 2004. The reduction in refinery utilization was primarily due to planned and unplanned maintenance in the second and fourth quarters of 2005.



**Product Purchase Costs**

The unfavourable impacts of lower refined product margins, lower volumes and lower refinery utilization were partially offset by lower third party refined product purchase costs in 2005 compared to 2004. Refined product purchase costs were higher in 2004 as a result of higher required purchased volumes of refined products to meet customer needs primarily due to a maintenance shutdown in 2004. Reduced third party purchase costs increased 2005 net earnings by $24 million.

**Cash and Non-cash Operating Expenses**

Overall, cash and non-cash operating expenses increased by $31 million after-tax in 2005 compared to 2004. Cash expenses increased by $20 million after-tax in 2005, primarily, due to higher energy and maintenance costs. Non-cash expenses increased by $3 million after-tax in 2005, due to increased depreciation as a result of a higher asset base. The higher 2005 expenses also reflect the absence of a 2004 mark-to-market gain of $8 million after-tax on inventory related derivatives.

**Related Party Transactions**

The Pioneer, UPI and SPC joint ventures are considered to be related parties to Suncor under GAAP. 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.

The following table summarizes our 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 third parties.

| ($ millions) | 2005 | 2004 | 2003 |
|---|---|---|---|
| Operating revenues | | | |
| Sales to EM&R joint ventures: | | | |
| Refined products | **327** | 320 | 301 |
| Petrochemicals | **279** | 272 | 187 |

At December 31, 2005, amounts due from EM&R joint ventures were $22 million, compared to $17 million at December 31, 2004.

**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 $11 million in 2005 compared to net earnings of $12 million in 2004 (2003 – $2 million after-tax loss).

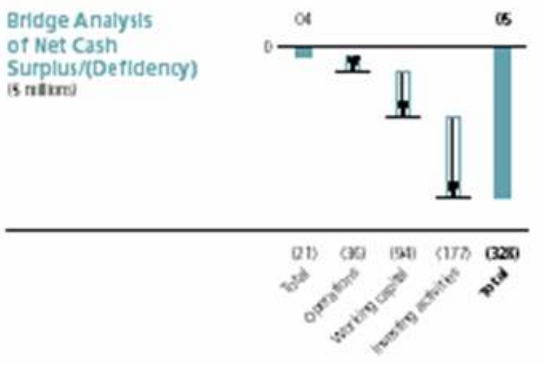
Energy trading activities, by their nature, can result in volatile and large positive or negative fluctuations in earnings. A separate risk management function reviews and monitors practices and policies and provides independent verification and valuation of these activities. See page 31.

**Net Cash Deficiency Analysis**

EM&R's net cash deficiency was $328 million in 2005 compared to a net cash deficiency of $21 million in 2004 (2003 – $29 million surplus). Cash

flow from operations was $152 million in 2005 compared to $188 million in 2004 (2003 – $164 million). The decrease was due to the same factors impacting net earnings. Net working capital increased by $44 million in 2005, compared to a decrease of $50 million in 2004. The increase in net working capital is a result of decreases in taxes payable.

Cash used in investing activities was $436 million in 2005 compared to $259 million in 2004 (2003 – $135 million). 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, we began construction on a diesel desulphurization project at our Sarnia refinery to meet federal sulphur regulations that will be effective June 2006 and anticipated future 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 also includes capital expenditures to expand the refinery's throughput capacity and enable it to process approximately 40,000 bpd of Oil Sands sour crude blends. In order to facilitate this portion of the project, there is a planned 50-day maintenance shutdown scheduled for the fall of 2006. When all components are completed in 2007, we expect this project will cost a total of approximately $800 million.

Construction of an ethanol plant began in June 2005 and is expected to be completed in 2006. This facility is expected to produce ethanol at a capacity of 200 million litres per year for blending into Sunoco-branded and joint venture retail gasoline. The project is expected to cost $120 million, and is on schedule and on budget.

Including capital investment associated with diesel desulphurization and construction of the ethanol plant, EM&R expects total capital spending to be approximately $350 million in 2006.

**Risk Factors Affecting Performance**

There are certain issues we strive to manage that may affect the performance of the EM&R business that include, but are not limited to, the following:

- Management expects that fluctuations in demand and 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. We believe 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 58 under Forward-looking Statements. Refer to the Suncor Overview, Risk Factors Affecting Performance on page 29.



**REFINING AND MARKETING – U.S.A.**

R&M operates a 90,000 barrel per day (bpd) (approximately 14,300 cubic metre per day) capacity refining complex in Commerce City, Colorado and 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, a 65% interest in the 140-kilometre Centennial pipeline system and a products terminal in Grand Junction, Colorado.

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 our Oil Sands operations.
- 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.
- Increasing the profitability and efficiency of our retail network.

**HIGHLIGHTS**

**Summary of Results**

| Year ended December 31<br>(Cdn$ millions unless otherwise noted) | 2005 | 2004 | 2003(1) |
|---|---|---|---|
| Revenue | **2 621** | 1 495 | 515 |
| Refined product sales | | | |
| (millions of litres) | | | |
| Gasoline | **2 517** | 1 627 | 636 |
| Total | **5 004** | 3 504 | 1 384 |
| Net earnings | **142** | 34 | 18 |
| Cash flow from operations | **247** | 59 | 34 |
| Investing activities | **408** | 198 | 300 |
| Net cash surplus (deficiency) | **(121)** | (71) | (220) |
| ROCE (%) (2) | **49.4** | 12.2 | — |
| ROCE (%) (3) | **28.9** | 11.0 | — |

(1) 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 our operating segments is calculated in a manner consistent with consolidated ROCE as reconciled in Non GAAP Financial Measures. See Page 56. For 2003, represents five months of operations since acquisition on August 1. Therefore no annual ROCE was calculated.
(3) Includes capitalized costs related to major projects in progress. See page 56.

**2005 Overview**

- On May 31, 2005, R&M acquired all of the issued shares of the Colorado Refining Company, an indirect wholly-owned subsidiary of Valero Energy Corporation for total cash consideration of $62 million, including additional associated price adjustments for purchased crude oil and product inventories. The acquired company's assets included a 30,000 bpd refinery in Commerce City, Colorado as well as a products terminal located in Grand Junction, Colorado.



- R&M continued construction on a project to modify the Commerce City refinery to allow it to meet regulations that take effect on June 1, 2006, requiring lower-sulphur diesel fuel. It is expected that modifications will also 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 was increased to US$390 million (approximately Cdn$465 million) from the previous estimate of US$300 million (approximately Cdn$360 million) due to labour shortages and material supply issues.
- Approximately 6% of feedstock processed at the refinery was synthetic crude oil of which approximately half was supplied from our Oil Sands operations.

**Analysis of Net Earnings**

R&M's net earnings were $142 million in 2005 compared to $34 million in 2004 (2003 – $18 million). Earnings have increased due to higher refining margins, and higher average sales volumes, due in part to the acquisition of the Colorado Refining Company during 2005, as well as higher refinery utilization. The acquisition increased our U.S. refining capacity to 90,000 bpd from 60,000 bpd. These positive impacts were partially offset by higher product purchase costs and higher cash and non-cash refinery operating expenses.

**Margins**

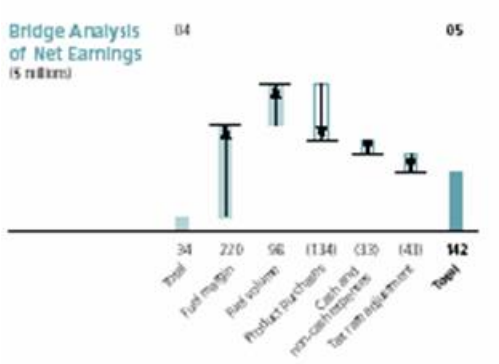
Average refining margins were 9.0 cents per litre (cpl) in 2005 compared to 6.7 cpl in 2004 reflecting significantly higher gasoline and diesel margins, partially offset by lower net realizations on asphalt and other heavy product sales. Refined product margins were impacted by the reduced supply of light oil products following the hurricane activity in the Gulf of Mexico during the summer of 2005. Higher refined product margins in 2005 increased earnings by $220 million. Retail margins were 5.1 cpl in 2005, compared to 5.4 cpl in 2004 due to competitive pressures that resulted in narrowing of margins.

**Volumes and Refinery Utilization**

Sales volumes increased in 2005, primarily due to the acquisition of a second refinery, bringing total throughput capacity in the second half of the year to 90,000 bpd from 60,000 bpd. In addition, higher refinery utilization rates resulting from more reliable operations in 2005 resulted in an increase in net earnings of $98 million.

Refinery utilization was 98% in 2005 compared to 92% in 2004. Refinery utilization in the first half of 2004 was negatively impacted by a planned 19-day maintenance shutdown on certain refinery units, as well as operating difficulties that were rectified during the shutdown.

Partially offsetting the positive impacts of higher margins and volumes, increased product purchases reduced net earnings by $134 million. The higher volume of purchased refined products was primarily due to purchases of additional intermediate feedstock to facilitate higher refinery utilization rates, along with purchases of other finished products to meet customer demands.




**Cash and Non-cash Expenses**

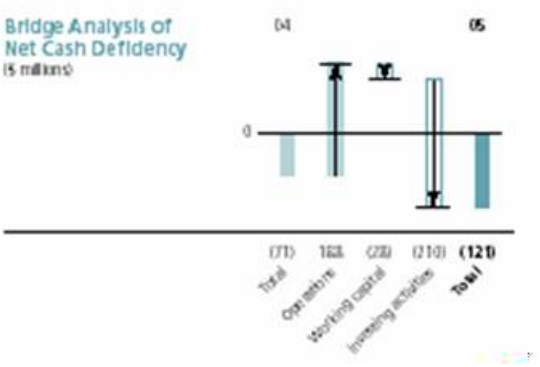
Increases in refinery cash expenses and non-cash depreciation, depletion and amortization were primarily due to incremental costs associated with the acquisition of the Colorado Refining Company as well as higher energy and maintenance related costs in 2005.



**Net Cash Deficiency Analysis**

R&M's net cash deficiency of $121 million in 2005 compared to a deficiency of $71 million in 2004 (2003 – $220 million deficiency). The increase in cash flow from operations to $247 million in 2005 from $59 million in 2004 (2003 – $34 million) was impacted by the same factors that affected net earnings. Net working capital decreased $40 million in 2005, compared to a decrease of $68 million in 2004 (2003 – $46 million decrease). The decrease in 2005 was primarily due to an increase in accounts payable related to capital expenditures on the refinery modifications, partially offset by an increase in accounts receivable and inventory as a result of higher product prices.

Cash used in investing activities was $408 million in 2005, compared to $198 million in 2004 (2003 – $300 million). Investing activities in 2005 were primarily related to costs associated with the refinery modification project, as well as the $62 million acquisition of Colorado Refining Company.




**Outlook**

R&M estimates spending approximately $225 million (approximately US$180 million) on capital project work in 2006. In 2006, we expect to complete modifications to the 60,000 bpd refinery acquired from ConocoPhillips (Commerce City west plant) to meet low-sulphur fuels regulations and expand the facility's capacity to process Oil Sands sour crude blends.

The refineries run a mixture of heavy and light crude oil feedstock from both Canadian and U.S. sources. In 2005, approximately 3% of R&M's crude slate came from Oil Sands. Suncor is currently assessing plans for 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 first quarter of 2006, 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, third party purchases and exchanges. This maintenance shutdown was originally scheduled to occur in the fourth quarter of 2005, but was postponed due to delays on the low-sulphur diesel project.

The United Steel Workers Union (USW) represents approximately 150 employees at R&M's Commerce City west plant. A contract extension was ratified in 2005 and will expire in January 2009. The same union represents approximately 87 employees at the east plant, acquired from Valero in May 2005. In February 2006, the east plant union voted to merge the east plant workers into the existing collective bargaining agreement at the west plant. The merged contract becomes effective in March 2006 and will expire in January 2009.

**Risk Factors Affecting Performance**

There are certain issues we strive to manage that may affect the performance of the R&M business including, but not limited to, the following:

- Continuing fluctuations in demand for refined products, margin and price volatility and market competitiveness, including potential new market entrants.

- 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, materials and other impacts of competing projects drawing on the same resources during the same time period. As well, our 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 58 under Forward-looking Statements. Refer to the Suncor Overview, Risk Factors Affecting Performance on page 29.



**NON GAAP FINANCIAL MEASURES**

Certain financial measures referred to in this MD&A are not prescribed by Canadian 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. We include 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 Canadian 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 our Consolidated Financial Statements.

| For the year ended December 31 | | 2005 | 2004 | 2003 |
|---|---|---|---|---|
| Cash flow from operations ($ millions) | A | **2 476** | 2 013 | 2 040 |
| Weighted average number of common shares outstanding (millions of shares) | B | **456** | 453 | 450 |
| Cash flow from operations (per share) | A/B | **5.43** | 4.44 | 4.53 |

**ROCE**

| For the year ended December 31 ($ millions, except ROCE) | | 2005 | 2004 | 2003 |
|---|---|---|---|---|
| **Adjusted net earnings** | | | | |
| Net earnings | | **1 245** | 1 088 | 1 087 |
| Add: after-tax financing expenses (income) | | **(16)** | 1 | (85) |
| | D | **1 229** | 1 089 | 1 002 |
| **Capital employed – beginning of year** | | | | |
| Short-term and long-term debt, less cash and cash equivalents | | **2 159** | 2 577 | 3 204 |
| Shareholders' equity | | **4 921** | 3 893 | 2 886 |
| | E | **7 080** | 6 470 | 6 090 |
| **Capital employed – end of year** | | | | |
| Short-term and long-term debt, less cash and cash equivalents | | **2 891** | 2 159 | 2 577 |
| Shareholders' equity | | **6 130** | 4 921 | 3 893 |
| | F | **9 021** | 7 080 | 6 470 |
| **Average capital employed** | (E+F)/2=G | **8 051** | 6 775 | 6 280 |
| **Average capitalized costs related to major projects in progress** (1) | H | **2 175** | 1 030 | 817 |
| **ROCE (%)** | D/(G-H) | **20.9** | 19.0 | 18.3 |

(1) Prior to 2004, average capital employed was calculated using a simple average of opening and closing major projects in progress. In 2004 and 2005, we have used a quarterly average.

**Oil Sands Operating Costs — Base Operations**

| (unaudited) | | 2005 (1) $ millions | 2005 (1) $ /barrel | 2004 (2) $ millions | 2004 (2) $ /barrel | 2003 $ millions | 2003 $ /barrel |
|---|---|---|---|---|---|---|---|
| Operating, selling and general expenses | | **978** | | 871 | | 865 | |
| Less: natural gas costs and inventory changes | | **(169)** | | (142) | | (176) | |
| Accretion of asset retirement obligations | | **24** | | 21 | | 21 | |
| Taxes other than income taxes | | **29** | | 28 | | 24 | |
| Cash costs | | **862** | **14.95** | 778 | 9.80 | 734 | 9.25 |
| Natural gas | | **216** | **3.75** | 158 | 2.00 | 169 | 2.15 |
| Imported bitumen (net of other reported product purchases) | | **2** | **0.05** | 13 | 0.15 | 4 | 0.05 |
| Cash operating costs – in situ operations | | **150** | **2.60** | — | — | — | — |
| Less: Cost of in-situ production sold directly to market | | **(107)** | **(1.85)** | — | — | — | — |
| Total cash operating costs – base operations | A | **1 123** | **19.50** | 949 | 11.95 | 907 | 11.45 |
| Start-up costs | | **12** | **0.20** | 26 | 0.35 | 10 | 0.10 |
| Add: in-situ inventory changes | | **—** | | 2 | — | — | — |
| Less: pre-start-up commissioning costs | | **(5)** | **(0.10)** | (4) | (0.05) | (10) | (0.10) |
| In-situ (Firebag) start-up costs | B | **7** | **0.10** | 24 | 0.30 | — | — |
| Total cash operating costs | A+B | **1 130** | **19.60** | 973 | 12.25 | 907 | 11.45 |
| Depreciation, depletion and amortization | | **448** | **7.80** | 484 | 6.10 | 458 | 5.80 |
| Depreciation, depletion and amortization – in-situ operations | | **34** | **0.60** | — | — | — | — |
| Less: Cost of in-situ production sold directly to market | | **(24)** | **(0.40)** | — | — | — | — |
| Total operating costs | | **1 588** | **27.60** | 1 457 | 18.35 | 1 365 | 17.25 |
| Production (thousands of barrels per day) | | **157.6** | | 217.0 | | 216.6 | |

**Oil Sands Operating Costs – Firebag In-situ Bitumen Production**

| (unaudited) | 2005 (1) $ millions | 2005 (1) $ /barrel | 2004 (2) $ millions | 2004 (2) $ /barrel |
|---|---|---|---|---|
| Operating, selling and general expenses | **150** | | 68 | |
| Less: natural gas costs and inventory changes | **(91)** | | (39) | |
| Accretion of asset retirement obligations | **—** | | — | |
| Taxes other than income taxes | **—** | | — | |
| Cash costs | **59** | **8.45** | 29 | 8.30 |
| Natural gas | **91** | **13.05** | 39 | 11.20 |
| Cash operating costs | **150** | **21.50** | 68 | 19.50 |
| Depreciation, depletion and amortization | **34** | **4.90** | 21 | 6.00 |
| Total operating costs | **184** | **26.40** | 89 | 25.50 |
| Production (thousands of barrels per day) | **19.1** | | 12.7 | |

(1) Production in the base operations for the year ended December 31, 2005 includes upgraded Firebag in-situ volumes of 775 bpd produced in the fourth quarter of 2005 during the Firebag Stage 2 start-up period.

(2) 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 Stage 1 start-up period.



**FORWARD-LOOKING STATEMENTS**

This Management's Discussion and Analysis contains certain Forward-looking Statements that are based on our current expectations, estimates, projections and assumptions that were made in light of our experience and our perception of historical trends.

All statements that address expectations or projections about the future, including statements about our 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," "future," "may," "slated," "strategy," "anticipates," "estimates," "plans," "intends," "believes," "projects," "indicates," "could," "focus," "vision," "goal," "proposed," "target," "objective," "expansion" and similar expressions. These statements are not guarantees of future performance and involve a number of risks and uncertainties, some of which are similar to other oil and gas companies and some of which are unique to us. Our actual results may differ materially from those expressed or implied by our 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 our products; commodity prices and currency exchange rates; logistical constraints to transport our product; 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 Firebag in-situ development and Voyageur) 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 or 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 Suncor's reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the impact of weather conditions on our drilling program; the impact of material and labour shortages; the impact of market demand for land and services on capital and operating costs; 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 timing and amount of insurance proceeds received in connection with the January 2005 fire at the Oil Sands facility; 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; and the occurrence of unexpected events, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect us. 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 our Annual Information Form/Form 40-F on file with Canadian securities commissions and the SEC. Readers are also referred to the risk factors described in other documents that we file from time to time with securities regulatory authorities. Copies of these documents are available without charge from Suncor.

## APPOINTMENT OF AUDITORS

The directors and management propose that PricewaterhouseCoopers LLP be appointed as Suncor's auditors until the close of the next annual meeting. PricewaterhouseCoopers LLP has been the company's auditors for more than five years.

Fees payable to PricewaterhouseCoopers LLP in 2004 and 2005 are detailed below.

| ($) | 2004 | 2005 |
|---|---|---|
| Audit Fees | 2 679 498 | 896 693 |
| Audit-related Fees | 23 050 | 123 792 |
| Tax Fees | 25 132 | 8 905 |
| All Other Fees | 6 150 | 6 405 |
| Total | 2 733 830 | 1 035 840 |

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.

None of the services described under the captions "Audit-related Fees", "Tax Fees" and "All Other Fees" were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.



## CORPORATE GOVERNANCE

Suncor's Board of Directors is committed to maintaining high standards of corporate governance, and regularly reviews and updates its corporate governance systems in light of changing practices, expectations and legal requirements.

Suncor is a Canadian reporting issuer. Our common shares are listed on both the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE). Accordingly, our corporate governance practices reflect applicable rules and guidelines adopted by the Canadian Securities Administrators (CSA) and the U.S. Securities and Exchange Commission (SEC), including the Sarbanes-Oxley Act of 2002. NYSE corporate governance requirements are generally not applicable to non-U.S. companies. However, Suncor has reviewed its practices against the requirementsof the NYSE applicable to U.S. domestic companies (NYSE Standards). Based on that review, Suncor's corporate governance practices in 2005 did not differ from the NYSE Standards in any significant respect, with the exception described below under the heading, "Compliance with NYSE Standards."

Suncor's Statement of Corporate Governance Practices (Statement) this year is based on the new disclosure rules adopted by the CSA, as set out in National Policy 58-201, "Corporate Governance Guidelines" (CSA Guidelines), and National Instrument 58-101, "Disclosure of Corporate Governance Practices." This Statement has been approved by the Board of Directors, on the recommendation of its Policy, Strategy Review and Governance (board policy) Committee.

Suncor's Statement can be found in Appendix B of this circular.

## GENERAL INFORMATION

The information contained herein is given as of March 1, 2006, except as otherwise indicated. A copy of the documents set out below may be obtained on our web site at www.suncor.com, or, without charge, by any person upon request from Suncor at 112 - 4th Avenue S.W., Calgary,

Alberta, T2P 2V5, by calling 1-800-558-9071, or by email requestto info@suncor.com:

1. Suncor's current annual report containing financial statements for the most recently completed financialyear and the report of the auditors relating thereto, together with any subsequent interim financial statements (the "annual report"); and

2. this circular.

In addition, persons resident in the United States may obtain a copy of Suncor's current Form 40-F and persons resident elsewhere may obtain a copy of Suncor's current Annual Information Form, together with a copy of any pertinent information incorporated by reference therein, without charge upon request to Suncor at the addressnoted above.

Information contained in or otherwise accessible through our web site does not form a part of this circular. All such references are inactive textual references only.

**Directors' Approval**

The contents and the sending of this circular have been approved by the directors of Suncor.



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

March 1, 2006



**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, 2005.

| | Number of Meetings |
|---|---|
| Board of Directors | 5 |
| 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 E. Benson | 5 of 5 | 10 of 10 |
| Brian A. Canfield | 5 of 5 | 11 of 11 |
| Susan E. Crocker | 3 of 3(2) | 6 of 6 |
| Bryan P. Davies | 5 of 5 | 13 of 13 |
| Brian A. Felesky | 5 of 5 | 13 of 13 |
| John T. Ferguson | 5 of 5 | 14 of 14 |
| W. Douglas Ford | 5 of 5 | 9 of 10 |
| Richard L. George | 5 of 5 | N/A(1) |
| Robert W. Korthals | 5 of 5 | 8 of 8 |
| M. Ann McCaig | 4 of 5(3) | 8 of 10 |
| Michael W. O'Brien | 5 of 5 | 9 of 9 |
| JR Shaw | 5 of 5 | 11 of 11 |

(1) As a member of management, Mr. George does not serve on any of the standing committees of the board.
(2) Ms Crocker did not stand for re-election in 2005 and accordingly ceased to be a director as of April 28, 2005.
(3) Mrs. McCaig was absent from one board meeting that occurred shortly after the death of her spouse.

The following summarizes the current membership of each committee:

| Committee | Committee Members As of February 28, 2006 | |
|---|---|---|
| Audit Committee<br>(all members independent) | John T. Ferguson (Chair)<br>Bryan P. Davies<br>Brian A. Felesky | Robert W. Korthals<br>Michael W. O'Brien |

| | | |
|---|---|---|
| Board Policy, Strategy Review and Governance Committee (all members independent) | John R. Huff (Chair)<br>Brian A. Canfield<br>John T. Ferguson | W. Douglas Ford<br>JR Shaw |
| Environment, Health and Safety Committee (all members independent) | M. Ann McCaig (Chair)<br>Mel E. Benson<br>Bryan P. Davies | Brian A. Felesky<br>Michael W. O'Brien |
| Human Resources and Compensation Committee (all members independent) | Brian A. Canfield (Chair)<br>Mel E. Benson<br>W. Douglas Ford | John R. Huff<br>M. Ann McCaig<br>JR Shaw |



**APPENDIX B: CORPORATE GOVERNANCE SUMMARY**

**Statement of Corporate Governance Practices**

Throughout this Statement, there are references to information available on our web site. All such information is available at www.suncor.com under the "Investor Centre" tab. Information on our web site, though referenced herein, does not form part of this Statement or this circular. In addition, shareholders may request printed copies of these materials by contacting one of the addresses set out on page 23.

**Board of Directors and Director Independence** (1)

The cornerstone of Suncor's governance system is its Board of Directors, whose duty is to supervise the management of Suncor's business and affairs.

The board is currently comprised of a majority (11 of 12 members) of independent directors. (2) The only Suncor director who is not independent is Richard L. George, Suncor's president and chief executive officer.(3) A short biography of each Suncor director can be found starting on page 5.

The board reviews the independence of its members annually. The board has adopted independence criteria for assessing the independence of directors including additional requirements applicable to members of the Audit Committee. In general terms, the board considers a director to be independent if that director has no material relationship with the company, either as partner, shareholder or officer of an organization that has a relationship with Suncor. The board's independence policy and criteria include a description of certain relationships that operate as a complete bar to independence. Suncor's independence criteria are consistent with the NSYE Requirements and the CSA Guidelines. The independence criteria are set out in Appendix E.

In applying the independence criteria, the board reviews and analyzes the existence, materiality and affect of any relationships between Suncor and each of its directors, either directly, through immediate family members or as a partner, significant shareholder or officer of another organization that has a relationship with Suncor, and determines in each case whether the relationships could, or could reasonably be perceived to, materially interfere with the director's ability to actindependently of management.

Some Suncor directors sit on the boards of other public companies. Particulars are set out in the biographical details on pages 5 to 7. (4) Some of these are companies with which Suncor has business relationships. The board has reviewed these relationships on a case-by-case basis against the independence criteria and has determined that none of these relationships impair the independence of the individual directors, as the directors do not serve as employees or executives of these other companies, their respective remuneration from these directorships is not personally material to them, and they are not personally involved in negotiating, managing, administering or approving contracts between Suncor and the other entities on whose boards they serve. The board's conflict of interest policy, described in detail below, precludes these directors from voting with respect to any of these arrangements, should they be considered at the board level. In the event there is any discussion of these arrangements or any arrangements involving competitors of these entities at the board level, these directors absent themselves from the boardroom and do not participate.

All of the board's four standing committees – Board Policy, Audit, Human Resource and Compensation (HR&CC) and Environment Heath and Safety (EH&S) – are comprised entirely of independent directors. Members of the Audit Committee are required to be financially literate. 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 director, to be such an expert. The criteria for assessing the financial literacy of Audit Committee members,and whether they qualify as an "audit committee financial expert", are set out in the board terms of reference, in Appendix C.

Suncor's independent directors meet in camera at the end of each board meeting without management present. Mr. George, as a member of management and the only Suncor director who is not independent, does not participate in these sessions. The sessions are presided over by JR Shaw, Suncor's independent chair since April 2001.(5) The board's committees also hold



in-camera sessions without management present following each of their meetings. These sessions are presided over by the independent chairs of the respective committees. Any issues addressed at the in-camera meetings requiring action on behalf of, or communication to management, are communicated to management by the independent chair or other independent director. For information about the number of board and committee meetings held during 2005, and directors' attendance at these meetings, see page 24.(6,7)

The roles and responsibilities of Suncor's independent chair are set forth in a position description that has been approved by the board. The position description is set out in Appendix D.(8)

**Board Mandate** (9)

The Board of Directors has approved and reviews at least annually its terms of reference. The board terms of reference, as the charter of the board, includes a general overview of the board's role in Suncor's governance, a statement of key guidelines and policies applicable to the board and its committees, and a mandate (Board Mandate) that describes its major responsibilities, 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. The terms of reference provide that in general, the board is responsible for the selection,monitoring and evaluation of executive management, and for overseeing the ways in which Suncor's business and affairs are managed, thereby assuming responsibility for the stewardship of the company. The full text of the board terms of reference is set out in Appendix C.

The Board of Directors delegates day-to-day management of Suncor's business to Suncor's CEO and other members of management. A management control process policy, adopted by the board, defines and sets limits on the authority delegated to management.

The following is a description of some key duties of the board as set out in the Board Mandate, with reference to the CSA Guidelines, including a description of the specific roles of board committees. The following description is not exhaustive. Formore information, please refer to Appendix C, and to the mandates of Suncor's board committees, available on our web site.

**Ethics** (10) The Board Mandate explicitly recognizes that the board, through the CEO, sets Suncor's standards of conduct,including our general moral and ethical tone, standards for compliance with applicable laws, standards for financial practices and reporting, qualitative standards for operations and products, and others. The Board Mandate also states that the board should be satisfied that the CEO and executive officers are creating and fostering a culture of integrity within Suncor. The board plays an active role in this area through its oversight of Suncor's business conduct code and compliance program (see *Ethical Business Conduct* on page 30), and through its assessment and evaluation of the performance of the CEO. The CEO's position description includes an accountability for setting a high ethical tone for the organization as a whole and fostering a culture of integrity throughout the organization. (See *Position Descriptions* on page 29).

**Strategic Planning** One of the board's major duties is to review with management Suncor's mission, objectives and goals, and the strategies for achieving them. The board is responsible for ensuring Suncor has an effective strategic planning process, and for annually approving the budget and the strategies reflected in Suncor's long range plan. A board meeting principally devoted to corporate strategy is held annually. The Board Policy Committee assists the board by annually assessing Suncor's planning and budgeting processes, and by reviewing and providing advice with respect to the early stages of key strategic initiatives and projects. It also works with management to design the annual strategy meeting,and assesses the effectiveness of this meeting.

**Risk Oversight** One of the major responsibilities of the board is to oversee the identification of the principal risks of Suncor's business and ensure there are systems in place to effectively monitor and manage them. To that end, the board undertakes an annual principal risk review. This includes an identification, classification and assessment of the principal risksof our business and an overview of risk management and mitigation strategies. Each principal risk is mapped to a board



committee, or the full board, as appropriate, for oversight, and to the CEO and other members of senior management with the key accountability in each risk area. The Audit Committee oversees the board's risk management governance model by conducting periodic reviews to reflect the principal risks of our business in the mandates of the board and its committees. For example, the EH&S Committee plays a role in reviewing environmental, health and safety issues and reporting to theBoard of Directors on these matters. The Audit Committee reviews financial risk management issues, programs and policies,including cash management, insurance and the use of financial derivatives. The Board Policy Committee assists the boardby reviewing and assessing emerging risk areas that do not fall under the mandate of another board committee.

**Succession Planning and Monitoring/Evaluating Senior Management** The board ensures the continuity of executive management by appointing a chief executive officer and overseeing succession planning for that key role. The HR&CC is specifically mandated to assist the board in this regard, by ensuring that appropriate executive succession planning and performance evaluation programs and processes are in place and are operating effectively. The HR&CC also reviews and reports to the Board of Directors on the succession plan for senior management positions, including the position of CEO. The HR&CC conducts an annual review of the CEO's performance against predetermined goals and criteria,and recommends to the board the total compensation of the CEO. (See *Compensation*, on page 31 as well as the Report on Executive Compensation on page 10).

**Communication/Disclosure Policy** Suncor has a disclosure policy, called "Communication with the Public", that establishes guidelines and standards for Suncor's communications with shareholders, investment analysts, other stakeholders and the public generally. The policy includes measures to avoid selective disclosure of material information, identifies designated Suncor spokespersons, and establishes internal review processes for key public communications. Suncor's business conduct code (see the information under the heading, *Ethical Business Conduct*, on page 30), addresses Suncor's obligations for continuous and timely disclosure of material information, and sets standards requiring directors, officers, employees and contractors trading in Suncor shares and other securities to comply with applicable law.

Suncor has disclosure controls and procedures designed to ensure that material information relating to Suncor is made known to our CEO and CFO. Suncor has a Disclosure Committee, chaired by its vice president and controller, and has designed and implemented due diligence procedures to support the financial reporting process and the certification of our financial reports by the CEO and CFO.

The Board of Directors is specifically mandated to ensure systems are in place for communication with Suncor's shareholders and other stakeholders. Suncor interprets 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 externalweb site, briefing sessions and group meetings. Suncor encourages and seeks stakeholder feedback through various channelsincluding corporate communications and investor relations programs, and through participation in the regulatory process.The board, either directly or through the activities of a designated board committee,

reviews and approves all quarterlyand annual financial statements and related management's discussion and analysis, management proxy circulars, annual information forms, and press releases containing significant new financial information, among others.

**Internal Controls** 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 and the effectiveness of management in ensuring the integrity and security of Suncor's electronic information systems and records. This includes a review of the evaluation of these systems by internal and external auditors.

**Corporate Governance System** The Board Policy Committee assists the Board of Directors with governance issues. Among other things, this committee monitors and reviews key corporate governance requirements, guidelines and best practices, making recommendations to the board where appropriate, and reviews and approves this Statement of Corporate Governance Practices. See Board Policy Committee, under the heading, *Board Committees*.



**Stakeholder Feedback** The Board Mandate currently provides that the board should ensure Suncor has systems in place to accommodate stakeholder feedback, and that these systems are appropriately resourced. Among other feedback mechanisms, Suncor currently maintains a 1-800 phone number as well as email and regular mail addresses for stakeholder feedback and questions. Shareholders may communicate directly with Suncor's independent chair by addressing correspondence to him at the address set out on page 23.

**Expectations and Responsibilities of Directors** The board terms of reference, supplemented by a board-approved accountability statement for directors, identifies the key expectations placed on board members. Directors are expected to review meeting materials in advance of board meetings, to encourage and facilitate discussion and questions at meetings. Directors must devote sufficient time and energy to their role as Suncor director to effectively discharge their duties to Suncor and the board. Board meeting dates are established well in advance and directors are expected to attend all meetings absent extenuating circumstances. Directors' attendance records for meetings held in 2005 are set out on page 24.

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.

**Board Committees** (11)

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. Each of these committees is comprised solely of independent directors. 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 withinthe 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.

The following is a brief summary of the key functions, roles and responsibilities of Suncor's board committees. The complete text of the mandates of each board committee is on our web site.

**Policy, Strategy Review and Governance Committee (Board Policy 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. It also reviews key matters pertaining to Suncor's values, beliefs and standards of ethical conduct. The committee also conducts the annual assessment of the overall performance and effectiveness of the Board of Directors, its committees, and individual directors.

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, risk management, security and certain other key financial matters.

In fulfilling its role, the Audit Committee monitors the effectiveness and integrity of Suncor'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 the 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. It also reviews any recommended appointees to the office of Chief Financial Officer. The committee also monitors Suncor's business conduct code compliance program. (See *Ethical Business Conduct* on page 30.)



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 and approves, with management and external auditors, significant financial reporting issues, the conduct and results of the annual audit, and significant finance, accountingand disclosure policies and other financial matters. The Audit

Committee also plays a key role in financial reporting, byreviewing Suncor's core disclosure documents, being its annual and interim financial statements, Management's Discussionand 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 informationto 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 reserves data and report of the Evaluator are annually reviewed by the committee prior to approval by the fullBoard of Directors.

The committee reviews Suncor's key policies and practices 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 Suncor'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, and reviews significant physical security management, IT security or business recovery risks and strategies to address such risks.

For additional information about Suncor's Audit Committee, including the Audit Committee Charter and our Pre-Approval Policies and Procedures, see Suncor's Annual Information Form dated March 1, 2006, filed at www.sedar.com.

**Environment, Health and Safety Committee** The Environment, Health and Safety Committee reviews the effectiveness with which Suncor meets its obligations and achieves its objectives pertaining to the environment, health and safety (EH&S). This includes the effectiveness with which management establishes and maintains appropriate EH&S policies. This committee also monitors management's performance and emerging trends and issues in these areas. In fulfilling its role, the committee monitors the adequacy of the Suncor's system of EH&S internal controls, and reviews quarterly management stewardship reports as well as the findings of significant external and internal EH&S investigations, assessments, reviews and audits. Suncor's periodic sustainability report, a detailed public disclosure document that includes reporting on Suncor's EH&S progress, plans and performance objectives, is also reviewed by the committee.

**Human Resources and Compensation Committee** For more information regarding the nature, scope, roles and responsibilities of the Human Resources & Compensation Committee, see "Report on Executive Compensation", on page 10.

**Position Descriptions** (12)

The board has developed and approved written position descriptions for the board chair, board committee chairs and the CEO. The board has also developed and approved a written position description, called an "Accountability Statement", for individual directors. For a summary of individual director accountabilities, see Expectations and Responsibilities of Directors, under the heading *Board Mandate* on page 28. The position description for the CEO includes a general description of therole as well as specific accountabilities in the areas of strategic planning, financial results, leadership, safety, government,environment and social relations, and management's relationship with the board.

The position descriptions form part of the charter of the Board of Directors, and as such are reviewed annually by the Board Policy Committee and changes are recommended by that committee to the full board. The position descriptions are all posted on Suncor's web site. In addition, the position description for Suncor's board chair is set out in Appendix D.



**Orientation and Continuing Education** (13)

Suncor provides orientation materials to new members of the Board of Directors, and conducts a formal orientation program for each new board member. The orientation includes in-person meetings with senior management on key legal, environmental, business, financial and operational topics central to Suncor's business and operations. The orientation also focuses on the role of the board, its committees and its directors, and the nature and operation of Suncor's business. A Directors' Handbook, containing information about the board and Suncor, including Suncor's core governance documents, is presented to each director upon joining the board. The handbook is continuously updated and is available for viewing by directors through a dedicated and secure directors' portal.(14)

Presentations and tours at the sites of Suncor's principal operations are provided to directors on a periodic basis, often in conjunction with board meetings, for the purpose of acquainting directors with Suncor's operations and the communities in which they are located. In 2005, in conjunction with scheduled board meetings, the directors toured Suncor's refining and retail operations in Colorado, as well as Suncor's oil sands operations near Fort McMurray, Alberta.

The board's Director Continuing Education Policy encourages directors to enrol in courses and programs that enhance and supplement their knowledge and skills in areas relevant to their role on Suncor's board, with the approval of the chairman of the board or Board Policy Committee. Through this program, Suncor's directors have taken courses in such diverse topics as reserves evaluation, financial accounting and corporate governance.

In conjunction with board meetings, management presents focused information to directors on topics pertinent to Suncor's business, including the impact of significant new laws or changes to existing laws, and opportunities presented by new technologies.(15) In an annual survey, directors are asked to suggest topics of interest for future information sessions.

**Ethical Business Conduct** (16)

**Code of Conduct** Sound, ethical business practices are fundamental to Suncor's business. Suncor has a Business Conduct Code ("Code") that applies to Suncor's directors, officers, employees and contractors.(17 ) The Code requires strict compliance with legal requirements and sets

Suncor's standards for the ethical conduct of our business. Topics addressed in the Code include competition, conflict of interest and the protection and proper use of corporate assets and opportunities, confidentiality, disclosure of material information, trading in shares and securities, communicationsto the public, improper payments, fair dealing in trade relations, and accounting, reporting and business control. Suncor'sCode is supported by detailed policy guidance and standards, and a Code compliance program, under which every Suncor director, officer, non-union employee and independent contractor is required to certify, on an annual basis, his or her compliance with the Code, that he or she has reviewed the Code at least once during the past year, and that he or she understands the requirements of the Code.

Suncor's board exercises stewardship over the Code in several respects. Suncor's internal auditors audit the compliance program annually, and the director of internal audit, who has direct reporting relationships with the Audit Committee, reports on compliance to that committee. In addition, at least once annually, the Code is reviewed and if appropriate, updated. Management reports to the Board Policy Committee annually on this process, and any recommended changes are approved by the Board Policy Committee.(18) Any waivers of Code requirements for Suncor's executive officers or members of the Board of Directors must be approved by the Board of Directors or appropriate committee thereof, and disclosed. No such waivers were granted in 2005.

Suncor encourages its employees to raise ethical concerns with Suncor management, our legal, corporate security, human resources or internal audit departments, without fear of retaliation. In addition, the board has established an "Integrity Hotline" to provide a means for Suncor employees to discuss issues of concern anonymously, with a third party service provider. The Integrity Hotline is available 24 hours a day, seven days a week. Any issues of a serious nature are investigatedby Suncor's internal auditors or security staff. The Audit Committee receives regular updates on activities relating to theIntegrity Hotline.

Suncor's Code of Conduct is available on Suncor's web site, under the "Governance" tab in the Investor Centre. (19)



**Conflicts of Interest** (20)

The board has adopted a policy relating to directors' conflicts of interest. Pursuant to this policy, directors are required to maintain with the Corporate Secretary a current list of all other entities in which they have a material interest, or onwhich they serve as a director, trustee or in a similar capacity. This list is made available to all directors through the directors' portal. Directors must immediately advise the Corporate Secretary of any deletions, additions or other changes to any information in their declaration of interest. If the change involves a change in the director's principal occupation or an appointment as director, officer or trustee of a publicly traded entity, the director must also notify the board chair, who will determine whether the change would be inconsistent with the directors' duties as a member of the board, and in appropriate circumstances, the board chair may request the director's resignation.

The Directors' Conflict of Interest Policy sets out clear procedures applicable in the event conflicts arise. If a director is a party to, or has an interest in any party to, a contract or transaction before the Board of Directors (regardless of the materialityof the contract or transaction), the director must immediately advise the board chair or the Board Policy Committee chair.The director's conflict or potential conflict is recorded in the minutes of meeting, and the director is required to absenthimself or herself from the meeting for any discussions or deliberations concerning the subject matter of the contractor transaction. The director is not allowed to vote on any resolution in respect of the contract or transaction.

The Corporate Secretary ensures that directors do not receive board materials in situations where the subject matter of those materials could involve an actual or potential conflict of interest.

**Nomination of Directors** (21)

The selection of new nominees for membership on Suncor's Board of Directors is conducted by the Board Policy Committee, comprised solely of independent directors.(22) More information on the responsibilities, powers and operations of the *Board Policy Committee* is found on page 28. (23)

The selection process includes an annual assessment of the competencies and skills the board as a whole should possess, and of current director capabilities. The Board Policy Committee utilizes the services of executive search consulting firms, which assist the committee in developing a list of the skills, experiences, qualifications, industry experience, diversity and personal qualities desired in potential new board members, and identifying and evaluating candidates based on these criteria. The committee or an elected sub-committee reviews candidates provided by the search firm, and from that list, selects a limited number of individuals for in-depth interviews, reference checks and more detailed assessments of matters such as independence, financial acumen, potential conflicts and the ability of the candidates to devote sufficient time and attention to a Suncor board position. Throughout the process, the committee provides updates to the board and solicits input on candidates. Candidates are interviewed by members of the committee and other directors as deemed appropriate. The Board Policy Committee ultimately provides its recommendation to the full Board of Directors, which approves a nominee for submission to shareholders for election to the board. (24)

**Compensation** (25)

**HR&CC** The HR&CC, comprised entirely of independent directors, assists the board in matters pertaining to board and executive compensation.

**Board Compensation** The HR&CC reviews and reports to the board on directors' compensation issues. The HR&CC has developed, in consultation with outside advisors, guidelines for director compensation based on, among other factors, directors' roles and responsibilities and an analysis of the competitive position of Suncor's director compensation program. The HR&CC annually reviews the competitiveness and form of board compensation, and makes recommendations to the full board on the level and form of board compensation and share ownership guidelines. The board has set director compensation based upon recommendations from this committee.

**CEO and Senior Executive Compensation** The HR&CC assists the board by annually reviewing the performance of the CEO and recommending his total compensation to the full board. The corporate objectives for which the CEO is responsible include a combination of corporate goals and personal goals, set annually by the Board of Directors in consultation with the HR&CC and board chair. The HR&CC annually reviews the CEO's performance against these objectives and against the key accountabilities of his position, as set out in the CEO's position description. The HR&CC reports its assessment to the full board which ultimately approves CEO compensation.

The HR&CC also reviews annually the CEO's evaluation of the other executive roles within the organization and his recommendation for their total compensation.

For more information about the HR&CC and the process and criteria for determining the CEO's total compensation, see *Report on Executive Compensation*, on page 10.

**Assessment of Directors** (26)

The Board Policy 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, if applicable. 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 by the Board Policy Committee, which then reports to the full Board of Directors with any recommendations for enhancing or strengthening effectiveness. The board chair reviews data relating to individual performance and conducts one-on-one meetings with each director as appropriate, focused on individual effectiveness.

**Compliance with NYSE Standards**

During 2005, Suncor's corporate governance practices did not differ from the NYSE Standards in any significant respect, with the exception of certain requirements applicable to equity compensation arrangements, reflecting differences between NYSE and TSX requirements. Under NYSE Standards, all such arrangements, and material revisions thereto, are subject to shareholder approval. The TSX rules, applicable to Suncor, only require shareholder approval for plans using newly issuedshares (as opposed to open market purchases of shares). The TSX rules also differ from the NYSE Standards in that theTSX requires shareholder approval every three years of equity compensation plans that permit a rolling maximum number of securities to be issued based on a fixed percentage of outstanding securities. This three-year renewal rule does not apply to plans which are subject to a fixed maximum number of securities (all of Suncor's equity compensation plans are subject to a fixed maximum). In addition, under the TSX rules, equity compensation plans that include a procedure for amendment need not be submitted to shareholders for amendment unless the amendment involves a reduction in exercise price or an extension of the term of options held by insiders. Generally, the stock exchange rules of NYSE and TSX are subject to limited exceptions that are not described in this summary.

(1) Reference: Form 58101F1, Item 1.
(2) Reference: Form 58101F1, Item 1(c).
(3) Reference: Form 58101F1, Item 1(b).
(4) Reference: Form 58101F1, Item 1(d).
(5) Reference: Form 58101F1, Item 1(f).
(6) Reference: Form 58101F1, Item 1(e).
(7) Reference: Form 58101F1, Item 1(g).
(8) Reference: Form 58101F1, Item 1(f).
(9) Reference: Form 58-101F1, Item 2.
(10) Reference: Form 58101F1, Item 5.
(11) Reference: Form 58101F1, Item 8.
(12) Reference: Form 58101F1, Item 3.
(13) Reference: Form 58101F1, Item 4.
(14) Reference: Form 58101F1, Item 4(a).
(15) Reference: Form 58101F1, Item 4(b).
(16) Reference: Form 58101F1, Item 5.
(17) Reference: Form 58101F1, Item 5(a).
(18) Reference: Form 58101F1, Item 5(a)(ii).
(19) Reference: Form 58101F1, Item 5(a)(i).
(20) Reference: Form 58101F1, Item 5(b).
(21) Reference: Form 58101F1, Item 6.
(22) Reference: Form 58101F1, Item 6(b).
(23) Reference: Form 58101F1, Item 6(c).
(24) Reference: Form 58101F1, Item 6(a).
(25) Reference: Form 58101F1, Item 7.
(26) Reference: Form 58101F1, Item 9.



**APPENDIX C: BOARD TERMS OF REFERENCE**

**Part I: Overview**

The *Canada Business Corporations Act* (the Act), Suncor's governing statute, provides "that the directors shall manage or supervise the management of the business and affairs of a corporation . . .". In practice, as a Board of Directors cannot "manage" a company such as Suncor in the sense of directing its day-to-day operations, the overarching role and legal duty of Suncor's Board of Directors is to "supervise" the management of Suncor's business and affairs. Accordingly, the Board of Directors oversees development of the overall strategic direction and policy framework for Suncor. Thisresponsibility is discharged through board oversight of Suncor's management, which is responsible for the day-to-dayconduct of the business. The board, through the chief executive officer (CEO), sets standards of conduct, including the company's general moral and ethical tone, compliance with applicable laws, standards for financial practices and reporting, qualitative standards for operations and products and other standards that reflect the views of the board as to the conduct of the business in the best interests of the company.

In general, then, the board is responsible for the selection, monitoring and evaluation of executive management, and for overseeing the ways in which Suncor's business and affairs are managed. In this way, the board assumes responsibility for the stewardship of the company. Specific responsibilities which facilitate the discharge of the board's stewardship responsibilities include: the strategic planning process, risk identification and management, ensuring that effective stakeholder communication policies are in place, and ensuring the integrity of internal controls and management information systems. These responsibilities, and others, are addressed in more detail in the board's Mandate, comprising Part IV of these Terms of Reference.

The Board of Directors discharges its responsibilities with the assistance of board committees. The committees advise and formulate recommendations to the board, but except in limited and specifically identified circumstances, do not have the authority to approve matters on

behalf of the Board of Directors. General guidelines relating to board committees comprise Part III of these Terms of Reference. In addition, each committee has a written mandate, setting out the scope of its operations, and its key roles and responsibilities. Position descriptions of the board committee chairs and the Board of Directors chair set out the related principles, framework and accountabilities for those key roles in Suncor's board governance.

The CEO of Suncor is delegated responsibility for day-to-day management of the company and for providing the company with leadership. The CEO discharges these responsibilities by formulating company policies and proposed actions, and, where appropriate, presenting them to the board for approval. The company's Management Control Process Policy explicitly identifies actions which have been specifically delegated to the CEO, and those which are reserved to the Board of Directors. In addition, the board has plenary power, and has the power to specify and modify the authority and duties of management as it sees fit with a view to Suncor's best interests and in accordance with current standards. The Act also identifies certain matters which must be considered by the board as a whole and may not be delegated to a committee or to management. These matters include:

- any submission to the shareholders of a question or matter requiring the approval of the shareholders;
- the filling of a vacancy among the directors or in the office of the external auditor;
- the manner of and terms for the issuance of securities;
- the declaration of dividends;
- the purchase, redemption or any other form of acquisition of shares issued by the company;
- the payment of a commission to any person in consideration of the purchase or agreement to purchase shares of the company from the company or from any other person, or procuring or agreeing to procure purchasers for any such shares;
- the approval of management proxy circulars;
- the approval of any take-over bid circular or directors' circular;
- the approval of the audited annual financial statements of the company; and
- the adoption, amendment or repeal of by-laws of the company.



One of the key stewardship responsibilities of the board is to approve the company's goals, strategies and plans, and the fundamental objectives and policies within which the business is operated, and evaluate the performance of executive management. Once the board has approved the goals, strategies and plans, it acts in a unified and cohesive manner in supporting and guiding the CEO. The CEO keeps the board fully informed of the progress of the company toward the achievement of its goals, strategies and plans, in a timely and candid manner, and the Board of Directors continually evaluates the performance of executive management toward these achievements.

**Part II: Board Guidelines**

The following have been adopted by the board as the guidelines applicable to the board and its operations:

- These Terms of Reference for the Board of Directors (which include the Board Guidelines, Committee Guidelines, Board Mandate and Board Forward Agenda, setting out the important issues that must be addressed by the Board of Directors annually), and the mandates and forward agendas of the board committees, constitute the charters of the board and committees respectively, and are reviewed by the board annually and updated as deemed appropriate. These charters are supplemented by the position descriptions for the board chair and board committee chairs, as well as the Director Accountability Statement.

- The CEO is responsible for leading the development of long-range plans for the company, including its goals and strategies. The board, both directly and through its committees, participates in discussions of strategy, by responding to and contributing ideas. The board annually reviews and approves the company's annual business plan (including the annual budget), and approves the strategies as reflected in the company's long range plan.

- The board believes that the appropriate size for the board is between 10 and 14 members.

- Directors stand for re-election annually.

- The Board maintains a Mandatory Retirement and Change of Circumstance policy and reviews the policy periodically to ensure it continues to serve the company's best interests. The board maintains a policy permitting directors to retain outside advisors at the expense of the company, subject to the written approval of any of the board chair, the chair of the committee proposing to retain outside advisors, or the Board Policy Committee. In exercising their approval authority, the board, board committee chair or Board Policy Committee, as the case may be, will establish, on a case-by-case basis, reasonable monetary limits and other controls as deemed appropriate.

- In order to support the alignment of directors' interests with those of Suncor's shareholders, directors shall own during the term of their directorship $400,000 in value of Suncor common shares, DSUs or any combination thereof, to be held by each director within five years of being appointed or elected to the board.

- The board should be comprised of a majority of independent directors. The board has defined an independent director in written independence criteria, based on the definition adopted by the New York Stock Exchange. On an annual basis, the Board of Directors shall consider and affirmatively determine whether each individual director is independent, in accordance with the criteria.

- The membership of the CEO on the Board of Directors is valuable and conducive to effective decision making. However, there should generally be no more than three inside (1) directors on the Board of Directors.

- The board supports the separation of the role of chair from the role of CEO.

- The board will evaluate the performance of the CEO at least annually. The evaluation will be based on criteria which include the performance of the business and the accomplishment of CEO's qualitative and quantitative objectives as established at the beginning of each fiscal year of the company, and the creation and fostering within the company of a culture of integrity.

(1) An inside director is an officer (other than an officer serving as such in a non-executive capacity) or employee of the company.



- The chair will work with the CEO to establish the agenda for each board meeting. Each board member is free to suggest the inclusion of items on the agenda. Whenever feasible, important issues should be dealt with over the course of two meetings. The first such meeting would allow for a thorough briefing of the board, and the second would allow for final discussion and a decision.

- The board will hold at least five meetings per year, one of which shall be principally devoted to strategy. An additional meeting shall be scheduled for approval of the annual proxy circular, annual information form and other annual disclosure documents, as necessary.

- Whenever feasible, the board will receive materials at least one full weekend in advance of meetings. Presentations on specific subjects at board meetings will only briefly summarize the material sent so discussion at the meeting can focus on questions and issues. Directors are expected to have reviewed these materials prior to attendance at board and committee meetings, and are expected to be prepared to engage in meaningful discussion and provide considered, constructive and thoughtful feedback and commentary at meetings.

- Board meeting dates will be established sufficiently in advance (at least one year and longer if practical) to minimize conflict with other commitments on directors' schedules. Directors are accordingly expected to make every reasonable effort to attend all meetings of the board and its committees, if not in person then by telephone.

- While the board does not restrict the number of public company boards that a director may serve on, each director should ensure that he or she is able to devote sufficient time and energy to carrying out their duties effectively.

- The board encourages the CEO to bring other executive officers into board meetings. The presence of such executives is expected to bring additional insights into the discussions, because of the executives' personal involvement in, and knowledge of, specific agenda items. The benefit of exposing the board to other executives, for succession planning and career development purposes, is recognized.

- The board is responsible for selecting its own members, and for assessing the performance of individual directors, as well as the effectiveness of board committees and the Board of Directors as a whole. The board delegates management of the selection processes to the Board Policy, Strategy Review and Governance (Board Policy) Committee. The Board Policy Committee has established a policy for director selection. The selection process includes consideration of the competencies and skills the board as a whole should possess, against those of existing directors, and a consideration of the competencies and skills each new nominee will bring to the board, as well as their ability to devote sufficient time and attention to fulfilling the role of director. The board ultimately determines nominees that will be included in the company's management proxy circular.

- The board supports the principle that its membership should represent a diversity of backgrounds, experience and skills.

- Succession and management development plans will be reviewed by the HR&CC, and reported annually to the board.

- At the conclusion of each board meeting, the Board of Directors shall meet on an "in-camera" basis without management. Such in-camera meetings shall be presided over by the independent chair. In addition, at least once annually, the independent directors will meet in the absence of both management and non-independent directors.

- At least once annually, the board will meet at a Suncor location other than the head office location. The purpose is to facilitate continual exposure of board members to the company's operations and the communities in which they are carried out.

**Part III: Committee Guidelines**

- The board has four standing committees: The Audit Committee, the Board Policy, Strategy Review and Governance Committee ("Board Policy Committee"), the Human Resources and Compensation Committee ("HR&CC"), and the Environment, Health and Safety Committee ("EH&SC"). From time to time the board may create ad hoc committees to examine specific issues on behalf of the board. Each committee maintains a written mandate and reviews that mandate annually. Any recommendations to amend committee mandates are reviewed by the Board Policy Committee for recommendation to the Board of Directors.



- The Board Policy Committee, with input from the chairman of the board, plans board committee appointments (including the designation of a committee chair) for recommendation to and appointment by the board. The committees shall be reconstituted annually following the annual general meeting at which directors are elected by the shareholders of the company. In accordance with the company's by-laws, unless otherwise determined by resolution of the Board of Directors, a majority of the members of a committee shall constitute a quorum for meetings of committees.

- Each committee shall be comprised of a minimum of three and a maximum of five directors. Each committee shall have a non-member secretary who may be a member of management of the company. The chair of each committee, in consultation with the committee secretary, shall determine the agenda for each committee meeting.

- Except where otherwise specified in these terms of reference or in Suncor's by-laws, each committee shall have the power to determine its own rules of procedure.

- The Audit Committee will consist entirely of outside, independent directors. In addition, all members of the Audit Committee must be, in the judgement of the Board of the Directors, financially literate (1), and at least one memberof the Audit Committee must be an audit committee financial expert (1). In general Audit Committee members willnot simultaneously be members of the Audit Committee of more than two other public companies, unless the Board of Directors affirmatively 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. Any such determination by the Board of Directors shall be disclosed in the company's management proxy circular.

- The HR&CC will consist entirely of outside, independent directors.

- The Board Policy Committee shall consist entirely of outside, independent directors.

- The chair is also an ex-officio of those committees of the board of which he is not a listed member.

- At the conclusion of each committee meeting, the committee shall meet on an "in camera" basis without management. Such in camera meetings shall be presided over by the chair of the committee, if an independent director, or other committee member who is an independent director, as selected by the independent directors on the committee.

**Part IV: Mandate of the Board of Directors**

**Goals of the Board**

The major goals and responsibilities of the board are to:

- establish policy direction and the fundamental objectives of the company;

- supervise the management of Suncor's business and affairs;

- ensure the company has an effective strategic planning process;

- identify the principal risks of Suncor's business, and ensure that there are systems in place to effectively monitor and manage these risks;

- annually approve the strategies reflected in Suncor's long range plan, which takes into account, among other things, the opportunities and risks of the company's business;

- protect and enhance the assets of the owners of the company and look after their interests in general;

- ensure the continuity of the company by assuming responsibility for the appointment of and succession to the office of the CEO, enforcing the articles and by-laws and by seeing that an effective board is maintained;

- make certain decisions that are not delegable, such as the declaration of dividends; and

- provide leadership and direction for Suncor in establishing and maintaining a high standard of corporate ethics and integrity.

(1) See Appendix A on page 39.



**Major Duties**

The major duties of the board are to:

1. Foster the long-term success of Suncor. Commit to the enterprise and acknowledge that the best interests of Suncor and its shareholders must prevail over any individual business interests of the membership of the board. Represent and safeguard the interests of all shareholders while recognizing that the interests of employees, customers, suppliers,and especially the general public must also be taken into account for the enterprise to continue being able to serveits owners. Monitor and work to improve return on, security of, and prospects for enhancement of the value of shareholder investment.

2. Determine and control in broad terms the purposes, goals, activities and general characteristics of Suncor. These duties range from establishing objectives, scope of operations, and fundamental strategies and policies and annually approving Suncor's annual budget and the strategies reflected in its long range plan, to declaring dividends, approving annual budgets, major capital investments, mergers and acquisitions, issuance or retirement of stock, and other specific actionsthat are likely to have a substantial effect on the company or that the board is legally required to take.

3. Review with management the mission of the company, its objectives and goals, and the strategies whereby it proposes to achieve them. Monitor the company's progress toward its goals and plans, and assume responsibility to revise and alter the company's direction where warranted.

4. Appoint a CEO, monitor and evaluate his performance, provide for adequate succession to that position, and replace the CEO when appropriate. Appoint as well the other officers of the company, and in respect of the senior officers, monitor their performance, that there is adequate succession to their positions, and that they are replaced when appropriate.

5. Ensure that the CEO is providing for achievement of acceptable current financial results relative to corporate objectives, budgets, and the economic environment, and the development of resources necessary to future success. These resources include:

   - management competence, organization and depth;
   - technology in exploration, production, mining, manufacturing, product design and product application;
   - fixed assets;
   - marketing capability – customer loyalty, distribution organization, market knowledge and so on;
   - workforce and employee relations;
   - financial resources, including relations with the financial community; and
   - reputation.

6. Establish an overall compensation policy for the company and monitor its implementation with special attention devoted to the executive group. Review the policy from time to time to ensure that it continues to be appropriate.

7. Oversee corporate financial operations, including:

   - capital structure management, maintaining reasonable financial flexibility and safety while achieving an appropriate return on equity;
   - financial results reporting;
   - allocation of assets, providing for increasing investment in areas of high return while withdrawing funds from areas producing inadequate returns;
   - maintaining access to suitable sources of new capital;
   - pension funds and other major employee benefit programs;
   - dividend pay-out policy and action;
   - selection of outside auditors for approval by the shareholders; and insurance.



8. Identify the principal risks of the company's business and ensure implementation and monitoring of systems to effectively manage these risks.

9. Ensure that processes are in place to monitor and maintain the integrity of the company's internal control and management information systems.

10. Ensure that the company has in place appropriate environmental, health and safety policies, having regard to legal, industry and community standards, and ensure implementation of management systems to monitor the effectiveness of those policies.

11. Ensure that systems are in place for communication and relations with stakeholder groups, including, but not limited to, shareholders; the investing public; government; employees; the financial community; and the communities in which Suncor operates. Ensure that measures are in place for receiving feedback from stakeholders, including toll free telephone and internet email communication channels that are adequately resourced to respond to appropriate enquiries. Monitor system effectiveness and significant sensitive and legally required communications.

12. Ensure that the company has systems in place to accommodate stakeholder feedback.

13. Collectively and individually respond constructively to requests for advice and assistance from the CEO. Provide leadership and policy direction to management with a view to establishing and maintaining a high standard of legal and ethical conduct for the company, by:

   - taking reasonable steps to ensure that Suncor complies with applicable laws and regulations, and with its constating documents, including Articles and By-laws, and operates to high ethical and moral standards; being on the alert for and sensitive to situations that

could be considered illegal, unethical or improper, and taking corrective steps;

- establishing the means of monitoring performance in this area with assistance of legal counsel;

- approving and monitoring compliance with key policies and procedures by which the company is operated; complying with the legal requirements, including those pursuant to the Canada Business Corporations Act, applicable to corporate boards of directors, including, without limitation, the duty to act honestly and in good faith with a view to the best interests of the company, and the duty to exercise the care, diligence and skill that reasonably prudent people exercise in comparable circumstances.

14. Manage board operations, including, without limitation:

- subject to any required shareholder approval, fix the size of the board, review its composition and, when appropriate, identify new nominees to the board;

- elect a chairman, appropriate committees and committee chairmen;

- define the duties of the chairman of the board and the committees;

- determine when and where the board meets;

- influence the structuring of agendas and how meeting time is spent; and

- meet legal requirements with respect to corporate administration.

Calgary, Alberta
Adopted by resolution of the Board of Directors on February 28, 1996.
Revision Dated November 30, 2005



**Appendix A to the Board Terms of Reference Financial Literacy and Expertise**

For the purpose of making appointments to the company's Audit Committee, and in addition to the independence requirements, all directors nominated to the Audit Committee must meet the test of financial literacy as determined in the judgment of the Board of Directors. Also, at least one director so nominated must meet the test of financial expert as determined in the judgment of the Board of Directors.

**Financial Literacy**

Financial literacy can be generally defined as the ability to read and understand a balance sheet, an income statement and a cash flow statement. In assessing a potential appointee's level of financial literacy, the Board of Directors must evaluate the totality of the individual's education and experience including:

- The level of the person's accounting or financial education, including whether the person has earned an advanced degree in finance or accounting;

- Whether the person is a professional accountant, or the equivalent, in good standing, and the length of time that the person actively has practised as a professional accountant, or the equivalent;

- Whether the person is certified or otherwise identified as having accounting or financial experience by a recognized private body that establishes and administers standards in respect of such expertise, whether that person is in good standing with the recognized private body, and the length of time that the person has been actively certified or identified as having this expertise;

- Whether the person has served as a principal financial officer, controller or principal accounting officer of a company that, at the time the person held such position, was required to file reports pursuant to securities laws, and if so, for how long;

- The person's specific duties while serving as a public accountant, auditor, principal financial officer, controller, principal accounting officer or position involving the performance of similar functions;

- The person's level of familiarity and experience with all applicable laws and regulations regarding the preparation of financial statements that must be included in reports filed under securities laws;

- The level and amount of the person's direct experience reviewing, preparing, auditing or analyzing financial statements that must be included in reports filed under provisions of securities laws;

- The person's past or current membership on one or more audit committees of companies that, at the time the person held such membership, were required to file reports pursuant to provisions of securities laws;

- The person's level of familiarity and experience with the use and analysis of financial statements of public companies; and

- Whether the person has any other relevant qualifications or experience that would assist him or her in understanding and evaluating the

company's financial statements and other financial information and to make knowledgeable and thorough inquiries whether:

- The financial statements fairly present the financial condition, results of operations and cash flows of the company in accordance with generally accepted accounting principles; and
- The financial statements and other financial information, taken together, fairly present the financial condition, results of operations and cash flows of the company.



**Audit Committee Financial Expert**

An "Audit Committee Financial Expert" means a person who, in the judgment of the company's Board of Directors, has the following attributes:

a. an understanding of Canadian generally accepted accounting principles and financial statements;

b. the ability to assess the general application of such principles in connection with the accounting for estimates, accruals, and reserves;

c. experience preparing, auditing or analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by Suncor's financial statements, or experience actively supervising one or more persons engaged in such activities;

d. an understanding of internal controls and procedures for financial reporting; and

e. an understanding of audit committee functions.

A person shall have acquired the attributes referred to in items (a) through (e) inclusive above through:

a. education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that involve the performance of similar functions;

b. Experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions;

c. Experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or

d. Other relevant experience.



**APPENDIX D: POSITION DESCRIPTION FOR INDEPENDENT BOARD CHAIR**

**Non-executive Chairman of the Board Suncor Energy Inc. Position Description**

The following principles shape the position description and duties for the chair of the Board of Directors of Suncor Energy Inc.

- The board's overarching duty is to "supervise" the management of Suncor's business and affairs.
- Suncor is committed to establishing and maintaining a well-developed governance process involving the board, board committees and management.
- Active involvement and substantive debate is encouraged.
- The board supports the separation of the role of chair from the role of CEO.
- The board is involved in strategic policy issues.
- The board will strive to be the best.

With the foregoing in mind, the framework for board chair will be:

1. The chair of the board is the chief officer of the board, appointed annually by the board with remuneration as determined by the board. The chair is not an employee or officer of the company and will be independent of management. The chair will foster and promote the integrity of the board and a culture where the board works harmoniously for the long-term benefit of the company and its shareholders.

2. The chair will preside at meetings of the board and at meetings of the shareholders of the company, as provided for in the by-laws of the company.

3. The chair will serve on the Board Policy, Strategy Review and Governance Committee of the board. The committee, by its mandate, assists the board in matters pertaining to governance, including the organization and composition of the board, the organization and conduct of board meetings and the effectiveness of the Board of Directors, board committees, and individual directors, in fulfilling their responsibilities. The chair is also an officio of those committees of the board of which he is not a listed member.

4. The chair will be kept well informed on the major affairs and operations of the company, on the economic and political environment in which it operates and will maintain regular contact with the chief executive officer and other senior executive officers of the company.

The accountabilities of the chair include:

**Shareholder Meetings**

- Subject to the by-laws, chair all shareholder meetings.
- Review and approve minutes of all shareholder meetings.

**Managing the Board**

- Subject to the by-laws, chair all board meetings.
- Provide leadership to the board.
- In conjunction with the Board Policy, Strategy Review and Governance Committee (Board Policy Committee), ensure that processes to govern the board's work are effective to enable the board to exercise oversight and due diligence in the fulfillment of its mandate.
- Identify guidelines for the conduct and performance of directors.
- Manage director performance.



- With the assistance of the corporate secretary and chief executive officer, oversee the management of board administrative activities (meeting schedules, agendas, information flow and documentation).
- Facilitate communication among directors.
- Attend committee meetings as deemed appropriate.
- Review and approve minutes of all board meetings prior to presentation to the board for approval.

**Develop a More Effective Board**

- Working with the Board Policy Committee, plan board and board committee composition, recruit directors, and plan for their succession.
- Working with the Board Policy Committee, participate in the board effectiveness evaluation process and meet with individual directors to provide constructive feedback and advice.
- Review any change in circumstance of individual directors and determine whether directors' other commitments conflict with their duties as directors of Suncor; review requests from the CEO to sit on the board of directors of outside business organizations.
- Review and approve requests from directors under the board's Directors Continuing Education Policy

**Working with Management**

- Support and influence strategy.
- With the assistance of the Human Resources and Compensation Committee, lead the board in evaluating the performance of the CEO.
- Build relationships at the senior management level.
- Provide advice and council to the CEO.
- Serve as an advisor to the CEO concerning the interests of the board and the relationship between management and the board.

**Liaison with Stakeholders**

- Share Suncor's views with other boards and organizations when required.
- Although primary responsibility for the company's relationships with the financial community, the press and other external stakeholders rests

with the chief executive officer, the chair may be requested, from time to time, to attend meetings with outside stakeholders.



**APPENDIX E: DIRECTOR INDEPENDENCE POLICY AND CRITERIA**

**Background**

The purpose of this independence policy and criteria is to state the criteria by which Suncor's board determines whether each of its directors is or is not independent.

**Independence Policy**

Pursuant to the terms of reference for Suncor's Board of Directors, a majority of the Board of Directors must be independent. In addition, the Audit, Board Policy, Governance and Strategy, and Human Resources and Compensation Committees, shall be comprised solely of independent directors. The Board Policy, Governance and Strategy Committee will conduct an annual review of the status of each director and director nominee in light of the following criteria for independence, and will recommend to the board in order that the board may affirmatively determine the status of each such individual. In makingindependence determinations, the board shall consider all relevant facts and circumstances. Material relationships can includecommercial, industrial, banking, consulting, legal, accounting, charitable and familial relationships. The key concern whenassessing independence is independence from management.

**Independence Criteria**

A director of Suncor will be considered independent only if the board has affirmatively determined that the director has no material relationship with Suncor, either directly or as a partner, shareholder or officer of an organization that has a relationship with Suncor (NYSE corporate governance rules). A "material relationship" is one which could in the view of Suncor's board, be reasonably expected to interfere with the exercise of the director's independent judgment (CSA Multilateral Instrument 52-110).

Notwithstanding the foregoing, a director will NOT be considered independent if:

- The director is or has been within the last three years, an employee or executive officer of the company, or an immediate family member (1) is or has been within the last three years, an executive officer, of the company.

- The director has received, or an immediate family member has received, during any 12-month period within the last three years, more than US$100,000 in direct compensation from Suncor, other than director and committee fees and pension or other forms of deferred compensation for prior service (provided such compensation is not contingent in any way on continued service) and other than compensation received by any immediate family member for service as an employee of Suncor (other than an executive officer).

- The director or an immediate family member is a current partner of a firm that is the company's internal or external auditor; a director is a current employee of such a firm; or a director's immediate family member is a current employee of such a firm and participates in the firm's audit, assurance or tax compliance (but not tax planning) practice; or a director or an immediate family member who was within the last three years (but is no longer) a partner or employee of such a firm and personally worked on the company's audit within that time. For the purposes of this point ONLY, "immediate family member" means only a spouse, minor child or stepchild, adult child or stepchild sharing a home with the director.

- The director or any immediate family member is or has been within the last three years employed as an executive officer of another company where any of Suncor's current executive officers at the same time serve on that company's compensation committee.

- The director is a current employee, or an immediate family member is a current executive officer, of a company that has made payments to, or received payments from, the company, for property or services in an amount which, in any of the last three fiscal years, exceeds the greater of US$1 million, or 2% of such other company's consolidated gross revenues.

(1) Unless otherwise noted, "immediate family member" is defined to include a person's spouse, parents, children, siblings, mothers and fathers in law, sons and daughters in law, brothers and sisters in law, and anyone other than domestic employees who shares such person's home.



- Contributions to tax exempt organizations shall not be considered "payments" for the purposes of these rules, provided that Suncor shall disclose in its proxy circular such contributions made to any tax exempt organization in which a directorserves as an executive officer, if within the preceding three years, contributions in any single fiscal year from the companyto the organization exceeded the greater of US$1 million, or 2% of such organization's consolidated gross reserves.

- For Audit Committee members only, in order to be considered independent, a member of an Audit Committee may not, other than in his or her capacity as a member of the Audit Committee, the Board of Directors or any other board committee, accept directly or indirectly any consulting, advisory, or other compensatory fee from Suncor, provided that compensatory fees do not include the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the company provided that such compensation is not contingent in any way on continued service; and in addition, shall not be an affiliated person of Suncor or any of its subsidiaries.

A director of Suncor will not be considered to have a material relationship with Suncor solely because the individual or his or her immediate family member:

- Has previously acted as an interim CEO of Suncor; or
- Acts, or has previously acted, as chair or vice chair of the board of directors of any board committees on a part-time basis; or
- Sits on the board of directors or as a trustee or in an equivalent capacity, of another company, firm or other entity, which has a business relationship with Suncor, provided that the individual's remuneration from the other entity is not personally material to that individual, the individual is not involved in negotiating, managing, administering or approving contracts between Suncor and the other entity, and the individual otherwise is in compliance with the board's conflict of interest policy with respect to contracts between Suncor and that other entity.

**EXHIBIT 99.4**

**Consent of PricewaterhouseCoopers LLP**



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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 March 1, 2006 relating to the consolidated financial statements, which appears in the Annual Report to Shareholders.

“PRICEWATERHOUSECOOPERS LLP”

Chartered Accountants
Calgary, Alberta
March 10, 2006

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**

**Consent of GLJ Petroleum Consultants Ltd.**

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**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 21, 2006 (collectively the "Reports"), prepared by GLJ Petroleum Consultants Ltd.:

- the Reserves Assessment and Evaluation of Canadian Oil and Gas Properties of Suncor Energy Inc. Natural Gas effective December 31, 2005;
- the Reserves Assessment and Evaluation of the synthetic crude oil reserves effective December 31, 2005 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, 2005.

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 2005 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,

**GLJ PETROLEUM CONSULTANTS LTD.**

"GLJ PETROLEUM CONSULTANTS LTD."

Dana B. Laustsen, P. Eng.
Executive Vice-President

Dated: March 10, 2006
Calgary, Alberta
CANADA

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**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 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 report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 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)) 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 report is being prepared;

   (b) 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

   (c) 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

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   (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 10, 2006

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

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**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 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 report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 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)) 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 report is being prepared;

   (b) 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

   (c) 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

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   (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 10, 2006

"J. KENNETH ALLEY"
J. KENNETH ALLEY
Senior Vice President and
Chief Financial Officer

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**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, 2005 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 10, 2006

**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, 2005 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 10, 2006