SUNCOR ENERGY INC. ANNUAL INFORMATION FORM

March 1, 2006

ANNUAL INFORMATION FORM

TABLE OF CONTENTS

TABLE OF CONTENTS ii
GLOSSARY OF TERMS iv
CONVERSION TABLE viii
CURRENCY viii
FORWARD-LOOKING STATEMENTS viii
NON GAAP FINANCIAL MEASURES ix
CORPORATE STRUCTURE 1
Name and Incorporation 1
Intercorporate Relationships 1
GENERAL DEVELOPMENT OF THE BUSINESS 2
Overview 2
Three-Year History 3
OIL SANDS (OS) 9
Operations 9
Principal Products 10
Principal Markets 10
Transportation 10
Competitive Conditions 11
Seasonal Impacts 11
Sales of Synthetic Crude Oil and Diesel 11
Environmental Compliance 12
NATURAL GAS (NG) 12
Marketing, Pipeline and Other Operations 12
Principal Products 13
Competitive Conditions 13
Seasonal Impacts 13
Environmental Compliance 13
ENERGY MARKETING & REFINING – CANADA (EM&R) 13
Procurement of Feedstocks 14
Refining Operations 14
Principal Products 15
Principal Markets 16
Transportation and Distribution 16
Competitive Conditions 17
Environmental Compliance 17
REFINING & MARKETING – U.S.A. (R & M) 17
Procurement of Feedstocks 17
Refining Operations 17
Principal Products 18
Principal Markets 18
Transportation and Distribution 19
Competitive Conditions 19
Environmental Compliance 20
MATERIAL CONTRACTS 20
RESERVES ESTIMATES 20
REQUIRED U.S. OIL AND GAS AND MINING DISCLOSURE 22
Proved and Probable Oil Sands Mining Reserves 22
Oil Sands Mining Operating Statistics 24
Proved Conventional Oil and Gas Reserves 24
Standardized Measure of Discounted Future Net Cash Flows from Estimated Production of Proved Oil and Gas Reserves after Income Taxes 27
Future Commitments to Sell or Deliver Crude Oil and Natural Gas 30

VOLUNTARY OIL SANDS RESERVES DISCLOSURE 31
Oil Sands Mining and Firebag In-Situ Reserves Reconciliation 31
SUNCOR EMPLOYEES 33
RISK FACTORS 33
SELECTED CONSOLIDATED FINANCIAL INFORMATION 40
Selected Consolidated Financial Information 40
Dividend Policy and Record 41
MANAGEMENT'S DISCUSSION AND ANALYSIS 41
DESCRIPTION OF CAPITAL STRUCTURE 41
General Description of Capital Structure 41
Ratings 41
MARKET FOR OUR SECURITIES 42
Price Range and Trading Volume of Common Shares 43
DIRECTORS AND EXECUTIVE OFFICERS 43
Directors 43
Executive Officers 43
Additional Disclosure for Directors and Executive Officers 44
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS 45
TRANSFER AGENT AND REGISTRAR 45
INTERESTS OF EXPERTS 45
FEES PAID TO AUDITORS 46
Fees Paid to Auditors 46
Audit Committee Pre-Approval Policies for Non Audit Services 46
Additional Audit Committee Information 46
RELIANCE ON EXEMPTIVE RELIEF 46
LEGAL PROCEEDINGS 47
ADDITIONAL INFORMATION 47

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.

Product:	**2005**		**2004**	
	(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.

Product:	**2005**		**2004**	
	(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.

Product:	2005		2004	
	(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.

Product:	**2005**		**2004**	
	(Thousands of cubic meters per day)	**(% of R&M's consolidate d 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 31st 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

	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**

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,	2005	2004	2003
($ per BOE of gross production)			
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

As at December 31, 2005	Crude Oil(3)		Natural Gas		Total	
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

As at December 31, 2005 (thousands of acres)	Developed		Undeveloped(1)		Total	
	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

For the year ended December 31, 2005

(number of net wells)	Net Exploratory			Net Development		
	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

For the year ended December 31, 2004

(number of net wells)	Net Exploratory			Net Development		
	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

For the year ended December 31, 2003

(number of net wells)	Net Exploratory			Net Development		
	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] Proved	Probable	Proved & Probable	Firebag In-situ Leases[1, 3] Proved[3]	Probable[3]	Proved & Probable	Total Mining and In-situ[3] 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] Proved	Probable	Proved & Probable	Firebag In-situ Leases[1, 3] Proved[3]	Probable[3]	Proved & Probable	Total Mining and In-situ[3] 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

	Year ended December 31,		
($ millions)	**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

2005	Price Range ($Cdn) High	Price Range ($Cdn) Low	Trading Volume (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

2005	Price Range ($US) High	Price Range ($US) Low	Trading Volume (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 .... Calgary, Alberta	Senior Vice President and Chief Financial Officer
MIKE M. ASHAR .... Denver, Colorado	Executive Vice President, Refining and Marketing – U.S.A.
DAVID W. BYLER .... Cochrane, Alberta	Executive Vice President, Natural Gas and Renewable Energy
RICHARD L. GEORGE .... Calgary, Alberta	President and Chief Executive Officer
TERRENCE J. HOPWOOD .... Calgary, Alberta	Senior Vice President and General Counsel
SUE LEE .... Calgary, Alberta	Senior Vice President, Human Resources and Communications
KEVIN D. NABHOLZ .... Calgary, Alberta	Executive Vice President, Major Projects
THOMAS L. RYLEY .... Toronto, Ontario	Executive Vice President, Energy, Marketing and Refining - Canada
JAY THORNTON .... Calgary, Alberta	Senior Vice President, Business Integration
STEVEN W. WILLIAMS .... Fort McMurray, Alberta	Executive Vice President, Oil Sands

Note:

(1) Offices shown are positions held by the officers in relation to business units of Suncor Energy Inc. and its subsidiaries on a consolidated basis. On a legal entity basis, Mr. Ashar is President of Suncor Energy (U.S.A.) Inc., Suncor's U.S. based downstream subsidiary, Mr. Ryley is the President of Suncor's Canadian based downstream subsidiaries, Suncor Energy Marketing Inc. and Suncor Energy Products Inc., respectively, and Mr. Nabholz, 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

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."

Harry Jung, P. Eng.
President

Calgary, Alberta, Canada
February 24, 2006