SUNCOR ENERGY INC.

ANNUAL INFORMATION FORM

March 3, 2008

ANNUAL INFORMATION FORM

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GLOSSARY OF TERMS

In this Annual Information Form (AIF), 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.

Best Estimate Resources

Is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. The best estimate of potentially recoverable volumes is generally prepared independent of the risks associated with achieving commercial production

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 may be upgraded into crude oil and other petroleum products.

Capacity

Maximum annual average output that may 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.

Contingent Resources

Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies.

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

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

Dry Hole/Well

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

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 working 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 February 27, 2008, 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, 2007, 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.

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[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. In addition, U.S. companies do not disclose resources but we believe this information is also useful to investors and accordingly disclose "contingent resources" in accordance with National Instrument 51-101. See "RESERVES ESTIMATES" on page 18 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.

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.

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 may 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.

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

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.

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 and Resources Disclosure - Oil Sands Mining and In-Situ Firebag Reserves Reconciliation".

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.

Remaining Recoverable Resources

The sum of reserves and contingent resources.

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 purification 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 lands are 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 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, or adjacent to, 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 were made by the company in light of its experience, and its perception of historical trends.

All statements that address expectations or projections about the future, including statements about 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," "estimates," "plans," "scheduled," "intends," "may," "believes," "projects," "indicates," "could," "focus," "vision," "goal," "proposed," "target," "objective," "continue" 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, many of which are beyond our control, 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, interest rates 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 Voyageur project, including our Firebag in-situ development) and regulatory projects (for example, the emissions reduction modifications at our Firebag in-situ development); 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; the cost of compliance with existing and future environmental laws; the accuracy of Suncor's 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; 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 (for example, the Government of Alberta's current review of the unintended consequences of the proposed Crown Royalty regime, and the Government of Canada's current review of greenhouse gas emission 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, and is not incorporated into the AIF by reference.

References herein to our 2007 Consolidated Financial Statements mean Suncor's audited consolidated financial statements prepared in accordance with Canadian generally accepted accounting principles (“GAAP”), the notes thereto and the auditor's report thereon, as at and for the three years in the period ended December 31, 2007.

NON GAAP FINANCIAL MEASURES

Certain financial measures referred to in this AIF that are not prescribed by GAAP, namely, cash flow from operations, Oil Sands cash and total operating costs per barrel and Return on Capital Employed (ROCE), 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 four principal subsidiaries and partnerships.

Suncor Energy Oil Sands Limited Partnership is an Alberta limited partnership that is indirectly wholly owned by Suncor Energy Inc. Effective February 1, 2005, Suncor Energy Inc., as general partner, and one of its wholly-owned subsidiaries, as a limited partner, formed the Suncor Energy Oil Sands Limited Partnership. At this time the partnership held certain net profits interests related to our oil sands business and natural gas business. Effective January 1, 2006, Suncor Energy Inc. contributed, subject to certain exceptions, its oil sands assets to the partnership. This internal reorganization had no effect on operations or on our consolidated net earnings.

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. We are 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. This company markets, 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 our Oil Sands business. Through this subsidiary we also administer Suncor's energy trading activities, market certain third party products, and procure crude oil feedstocks and natural gas for our downstream business. This subsidiary markets certain natural gas volumes produced by, and purchased from, our Natural Gas business unit. Suncor Energy Marketing Inc. also has a petrochemical marketing division that holds a 50% interest in Sun Petrochemicals Company, a petrochemical products joint venture.

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 owned pipelines in Wyoming and Colorado.

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

Suncor is 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 three 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, diesel fuel and by-products. 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 and natural gas liquids 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 internal consumption. 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, Refining and Marketing, refines crude oil at Suncor's refineries in Sarnia, Ontario, and Commerce City, Colorado, into a broad range of petroleum, petrochemical and biofuel products. These products are then marketed to industrial, wholesale and commercial customers principally in Ontario, Quebec and Colorado. In Ontario, our retail businesses are managed through Sunoco-branded and joint venture operated retail networks, and in Colorado our retail businesses are managed through Phillips 66 ® - branded sites. We also transport crude oil on our wholly owned pipelines in Wyoming and Colorado, and engage in third party energy marketing and trading activities through this business.

For financial reporting purposes, we also report financial data for activities not directly attributable to an operating business under the results of Suncor's "Corporate" segment. This includes the activity of our self-insurance entity, as well as investments in wind energy.

In 2007, we produced approximately 271,400 boe per day, comprised of 238,700 barrels per day (bpd) of crude oil and natural gas liquids and 196 million cubic feet per day (mmcf/d) of natural gas. In 2006, the most recent period with published results, we were the second largest crude oil and natural gas liquids producer in Canada (approximately 10%[3] of Canada's crude oil production in 2006) and the 16th largest natural gas producer in Canada.[4]

In 2007, our Refining and Marketing business sold approximately 210,700 bpd (2006 – 185,600 bpd) or 33,500 m^3 per day (2006 – 29,500 m^3 per day) of refined products, mainly in Ontario and Colorado, but also in other states throughout the United States and in Europe.

[3] CAPP Crude Oil Report – Table 1 Canadian Crude Oil Production Forecast
[4] Oilweek – July 2007, Top 100 Oil and Gas Producers

Three-Year History

Oil Sands (OS)

Over the past three years we have continued to advance our multi-phased growth strategy to increase production capacity to 550,000 bpd in 2012. Key milestones and significant events that have affected our Oil Sands business during this time period include the following:

- Oil Sands Fire – A fire on January 4, 2005 caused significant damage to one of our two upgraders, reducing upgraded crude oil production capacity from 225,000 bpd to about 122,000 bpd for the first nine months of 2005. Repair and maintenance work to restore the facility was completed in September 2005. Our property loss and business interruption insurance policies substantially mitigated the financial impact of the fire, and were fully settled in 2006.

- New Vacuum Unit and Debottleneck – During the fourth quarter of 2005, we increased our production capacity to 260,000 bpd through the completion of a new vacuum unit. In addition, we also completed a debottleneck of our Steepbank mine operation.

- Firebag Stage 2 – Firebag Stage 2 commenced commercial operations in the first quarter of 2006, furthering our plans to increase bitumen supply.

- Royalties – In November 2006, we exercised our option, under our royalty agreement with the Government of Alberta (the "Crown Agreement"), to transition our base oil sands mining operations and associated upgrading from a royalty assessed on upgraded product values to a bitumen-based royalty starting on January 1, 2009.

- Voyageur South Mine Extension – In July 2007, Suncor filed a regulatory application for the Voyageur South mine extension. Bitumen produced at the proposed project is expected to provide additional feedstock flexibility.

- Operating Permit – We were issued a new 10-year operating approval in connection with our Oil Sands business in August 2007.

- Firebag Cogeneration – A capital project expanding Firebag Stages 1 and 2 in conjunction with the addition of a cogeneration facility was completed in 2007.

- Regulatory Requirements

    - In September 2007, high emissions at our in-situ operations resulted in orders being issued by both Alberta Environment and the Alberta Energy and Utilities Board. Until regulators can be assured emissions are stable at compliant levels, production at the in-situ operation has been capped at approximately 42,000 bpd.

    - In December 2007, high emissions at our base plant resulted in an order being issued by Alberta Environment. Emissions at the oil sands plant exceeded air quality standards, and accordingly we are upgrading our emission control equipment and reducing discharges to the tailings ponds. In addition, we have introduced processing changes and are undertaking a more comprehensive monitoring program.

- Progress on Growth Projects – At December 31, 2007, the addition of a new set of cokers to our upgrading complex was approximately 95% complete. This expansion is expected to increase production capacity to 350,000 bpd, with construction completion targeted in the second quarter of 2008 and ramp-up to full capacity expected in the fourth quarter. Other work included construction of a naphtha unit (which is intended enhance product mix) which was approximately 20% complete at year-end, and the Steepbank extraction plant which was approximately 25% complete at year-end. For further discussion of our significant capital projects, see page 19 of our MD&A.

The following changes to our Oil Sands business have occurred, or are expected to occur in 2008:

- Royalty Amending Agreement – In January 2008, we entered into the Suncor Royalty Amending Agreement with the government of Alberta, which modifies the rates under the Generic Regime which would otherwise apply to our base mining operations, assuming the government enacts their proposed framework. Under this agreement, prior to January 1, 2010, we would expect to pay a royalty in respect of our base operations of 25% of the difference between a project's annual gross revenues net of related transportation costs, less allowable costs including allowable capital expenditures (R-C), and from January 1, 2010 through to January 1, 2016, we would expect to pay royalties in accordance with the rates in the Generic Regime, subject to a cap of 30% of R-C. (See page 19 of our MD&A for more information.)

- Voyageur Growth Plan – In January 2008, Suncor's Board of Directors approved a $20.6 billion investment that is expected to boost crude oil production capacity at the company's oil sands operation by 200,000 bpd, bringing the total capacity to 550,000 bpd in 2012. The expansion plans include constructing four additional stages of in-situ bitumen production, a new upgrader (Suncor's third) to convert that bitumen into higher-value crude oil, and various infrastructure and utilities.

- Petro-Canada Agreement – Incremental bitumen to feed the expanded Oil Sands operation is expected to be partially obtained starting in 2008 under a processing agreement between Suncor and Petro-Canada. Under the terms of the agreement, we will process a minimum of 27,000 bpd of Petro-Canada bitumen on a fee-for-service basis. Petro-Canada retains ownership of the bitumen and resulting sour crude oil production of about 22,000 bpd. In addition, Suncor has agreed to sell an additional 26,000 bpd of our proprietary sour crude oil production to Petro-Canada. Both the processing and sales components of the agreement are for a minimum 10-year term.

Natural Gas (NG)

Key milestones and significant events that have affected our Natural Gas business during the past three years include the following:

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

- 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. We have a 37.5% ownership interest and continue to operate the Simonette gas plant.

- South Rosevear Gas Plant – In January 2006, 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.

- Acquisition – In March 2007, we acquired developed and undeveloped lands in British Columbia for approximately $160 million.

Refining and Marketing (R&M)

Consistent with the company's organizational restructuring during the first quarter of 2007, results from our Canadian and U.S. downstream marketing and refining operations have been combined into a single business segment – Refining and Marketing. Key milestones and significant events that have affected our Refining and Marketing business during the past three years include the following:

- Valero Acquisition – On May 31, 2005 we acquired a refinery from Valero Energy Corporation ("Valero") in the Denver area adjacent to our existing refinery. The 30,000 bpd Valero refinery was purchased for $37 million (US$30 million) plus working capital and associated oil and product inventory adjustments, for a total acquisition cost of $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. This facility was integrated with our existing U.S. refinery. Our current combined refining capacity is approximately 90,000 bpd in the U.S.

- Reduced Refinery Air Emissions – In connection with the acquisition of a 60,000 bpd refinery from ConocoPhillips on August 1, 2003, we assumed obligations at the refinery pursuant to a Consent Decree with the United States Environmental Protection Agency to reduce air emissions. These obligations were met during a planned maintenance shutdown in 2006 for a total cost of approximately $60 million (approximately US$50 million).

- Diesel Desulphurization and Oil Sands Integration – In July 2006, the Commerce City refinery completed its diesel desulphurization and oil sands integration project at a total cost of approximately $530 million (US$435 million). The completion of the project allows the refinery to produce ultra low sulphur diesel to meet requirements of fuels desulphurization legislation, and enable the refinery to process up to 15,000 bpd of oil sands sour crude oil. In addition, the modifications increased the refinery's ability to process a broader slate of synthetic crude oil.

- Ethanol Plant – In July 2006, we completed our St. Clair ethanol facility on time and on budget, for a final cost of $112 million, and with a production capacity of 200 million litres per year. The ethanol produced is primarily blended into our Sunoco-branded fuels and fuels sold through our joint venture operated networks. Natural Resources Canada contributed $22 million towards this project through their Ethanol Expansion Program. This contribution of $22 million includes a repayment obligation and we have already repaid $2 million to date.

- Diesel Desulphurization and Oil Sands Integration – In November 2007, Suncor completed the final phase of a three year $950 million project at the Sarnia refinery. A 120-day shutdown to complete the tie-ins was the last step in the multi-phased project. The project increased the amount of oil sands crude oil the refinery can upgrade, improved the facility's environmental performance, and commencing in 2006 enabled the production of ultra low sulphur diesel fuel.

Other

Renewable Energy

In addition to renewable energy investments in ethanol production through our Refining and Marketing segment, Suncor also invests in renewable wind power. Suncor is a partner in four wind power projects, including two projects commissioned in the past three years.

In November 2006, we, along with our joint venture partners, Enbridge Income Fund and Acciona Wind Energy Canada Inc., officially opened a 30-megawatt wind power project near Taber, Alberta called the Chin Chute Wind Power Project. The project includes 20 wind turbines with the capacity to produce enough zero-emission electricity to offset the equivalent of approximately 102,000 tonnes of carbon dioxide per year.

In September 2007, we, along with our joint venture partner Acciona Wind Energy Canada Inc, officially opened a 76-megawatt wind power plant near Ripley, Ontario. The $176 million Ripley Wind Power Project consists of 38 wind turbines, a 27-km transmission line and two electrical substations. The project is expected to displace at least 66,000 tonnes of carbon dioxide per year.

Other Transactions

Throughout 2005, $40 million was received for the provision of training services associated with the sale of certain proprietary technology in 2004. Amounts are being recognized into income over the term of the sale agreement.

NARRATIVE DESCRIPTION OF THE BUSINESS

OIL SANDS (OS)

Suncor produces a variety of refinery feedstock, diesel fuel and by-products by developing the Athabasca oil sands in northeastern Alberta and upgrading the bitumen extracted at our plant near Fort McMurray, Alberta. Our Oil Sands operations, accounting for virtually all of our conventional and synthetic crude oil production in 2007, represent a significant portion of our 2007 capital employed[5] (65%), cash flow from operations[5] (79%) and net earnings (87%). 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.

1) Bitumen is supplied from a combination of a mining operation using trucks and shovels, an in-situ operation and third party bitumen supply.

2) Extraction facilities recover the bitumen from the oil sands ore that is mined. Since late 2005, bitumen from Firebag is being upgraded, with only a small portion of production being strategically sold directly into the market.

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

4) Utilities for the operation (water, steam and electricity) are generated through facilities on site, some of which are owned and operated by Suncor, and others which are owned and operated by third parties.

Mining/Extraction - 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 a sizing plant followed by an ore preparation plant. Here, the oil sands ore 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. In extraction, bitumen is extracted from the oil sands ore using a hot water process. After the final removal of impurities and minerals, naphtha is added to dilute the bitumen to facilitate transportation to upgrading.

In-situ - 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 on-site steam generation facilities is injected through the top well into the oil sands. 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. For current stages of in-situ development, naphtha is added to dilute the bitumen to facilitate transportation to upgrading. Future stages propose to use a heated pipeline instead of naphtha dilution for transport.

Upgrading - After the diluted bitumen is transferred to the upgrading plant, the naphtha is removed and recycled to be used again as diluent. The bitumen from both SAGD and mining 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. Four separate streams of refined crude oil are produced: diesel, naphtha, kerosene and gas oil.

[5] Refer to "Non GAAP Financial Measures" on page ix of this AIF.

We continue to explore and develop improved and alternative technologies to facilitate increased efficiency and processing within our operations. For example, based on the results of testing performed during the past two years, we plan to utilize new mining technology and processes in our future mine development plans. This technology is incorporated in the July 2007 regulatory application for the planned Voyageur South Mine extension.

While there is virtually no finding cost associated with synthetic crude oil, the delineation of the resource and development and expansion of production entail significant capital outlays. For the same reason, the costs associated with synthetic crude oil production are largely fixed in the short term, 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 in SAGD production at our Firebag operations, and accordingly natural gas prices are a key variable component of synthetic crude oil production costs.

In the normal course of our operations we regularly complete planned maintenance shutdowns of our Oil Sands facilities. These shutdowns are scheduled, and provide both preventative maintenance and capital replacement which are expected to improve our operational efficiency. In July 2007 a scheduled maintenance shutdown of Upgrader 2 occurred to facilitate the tie-in of new coker units, an important milestone in the capital expansion project to increase Oil Sands production capacity to 350,000 bpd in the second half of 2008. A 30-day planned shutdown of Upgrader 1 is expected to occur in 2008.

Principal Products

Sales of light sweet synthetic crude oil and diesel represented 59% of Oil Sands consolidated operating revenues in 2007, compared to 53% in 2006. The other significant component of our revenues were light sour synthetic crude oil and bitumen sales of 38% (2006 – 43%). 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:	2007		2006	
	(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	126.7	59	138.7	53
Light sour crude oil / bitumen	108.0	38	124.4	43
Total	234.7		263.1	

We anticipate that approximately 47% of Oil Sands sales in 2008 will be light sweet synthetic crude and diesel products.

Principal Markets

We market our crude oil product blends principally to customers in Canada and 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 entered into a transportation service agreement with a subsidiary of Enbridge Inc. 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. In addition, in 2008 we committed to an additional 12,000 bpd that underpins current expansion plans for the pipeline.

In 2005, Suncor 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 currently 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.

Suncor has entered into long term service agreements with affiliates of TransCanada Corporation for transportation of crude oil on the Keystone pipeline. The agreements will provide for pipeline transportation of our crude oil from Hardisty, Alberta to both Patoka, Illinois and Cushing, Oklahoma. Transportation of crude oil on the Keystone pipeline is targeted to commence in 2009.

We continue to evaluate additional pipeline agreements to support our expected production capacity of 550,000 bpd in 2012.

Periodically, we also enter into strategic short term cargo transport agreements to ship synthetic crude oil to the United States Gulf Coast. These agreements have a term of less than one year, and are specific to individual shipments.

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 mining facilities are readily accessible by public road. Our Firebag in-situ facilities are currently accessible by private road. We anticipate termination of such access in 2010, and are currently evaluating alternative means of access.

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 winter climatic conditions at Oil Sands can cause reduced production 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. Primary markets for our crude oil products include refining operations in Alberta, Ontario, the U.S. Midwest and the U.S. Rocky Mountain region. Diesel products are sold primarily in Western Canada.

In 1997, we entered into a long-term agreement with Flint Hills Resources LLC ("Flint Hills") to supply Flint Hills with up to 30,000 bpd (approximately 13% of our average 2007 total production (2006 – 11%)) of sour crude from the Oil Sands operation. We began shipping the crude to Flint Hills at Hardisty, Alberta (from which Flint Hills ships the product to its refinery in Minnesota) on 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 CCRL with 20,000 bpd of sour crude oil production. In 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. Both CCRL agreements extend through to 2011, with renewal options that could extend out to 2018 and beyond. Both agreements continue until terminated by either party with twenty-four months notice. Neither party has provided notice of termination at this time.

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 no later than January 1, 2009. Under the agreement, we will process a minimum of 27,000 bpd of Petro-Canada bitumen on a fee for service basis. Petro-Canada will retain ownership of the bitumen and resulting sour crude oil production of about 22,000 bpd. In addition, we will sell an additional 26,000 bpd of our proprietary sour crude oil production to Petro-Canada. Both the processing and sales components of the agreement are for a minimum 10-year term.

There were no customers that represented 10% or more of our consolidated revenues in 2007, 2006, or 2005.

A portion of our Oil Sands production is used in our Sarnia and Commerce City refining operations. During 2007, the Sarnia refinery processed approximately 7% (2006 - 8%) of Oil Sands crude oil production and the Commerce City refinery processed approximately 6% (2006 – 3%) of Oil Sands crude oil production.

Environmental Compliance

For a discussion of environmental risks at our Oil Sands operations, refer to the "Legal and Regulatory Risks" outlined in the "Risk Factors" section of this Annual Information Form, as well as the "Asset Retirement Obligations" section 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 and natural gas liquids in Western Canada, supplying markets throughout North America. The sale of NG's production provides a natural price hedge for natural gas purchased for internal consumption.

In 2007, natural gas and natural gas liquids accounted for approximately 98% of the NG business unit's production (2006 – 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.

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 135 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 87% of our natural gas production is sold to Suncor Energy Marketing Inc. and then 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.

Approximately 13% 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 Northwest 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. 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 88% (2006 – 90%) of NG's consolidated operating revenues in 2007, with the remaining 12% (2006 – 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 NG's consolidated operating revenues by product for the last two years.

Product:	**2007**		**2006**	
	(Millions of cubic feet equivalent per day)	**(% of NG consolidated revenues)**	**(thousands of barrels of oil equivalent per day)**	**(% of NG consolidated revenues)**
Natural gas	196	88	191	90
Crude Oil and Natural gas liquids	19	12	18	10
Total	215		209	

Competitive Conditions

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

Seasonal Impacts

Risks and uncertainties associated with weather conditions and wildlife restrictions can shorten the winter drilling season and impact the spring and summer drilling programs, potentially resulting in increased costs or reduced production.

Environmental Compliance

For a discussion of environmental risks at our NG operations, refer to the "Legal and Regulatory Risks" outlined in the "Risk Factors" section of this Annual Information Form, as well as the "Asset Retirement Obligations" section under "Critical Accounting Estimates" in the "Suncor Overview and Strategic Priorities" section of our MD&A.

REFINING AND MARKETING (R&M)

Consistent with the company's organizational restructuring during the first quarter of 2007, results from our Canadian and U.S. downstream marketing and refining operations have been combined into a single business segment – Refining and Marketing.

Our Canadian-based refining and marketing business operates in Central Canada. Our refinery in Sarnia, Ontario, has a crude oil capacity of 70,000 bpd and 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. Our ethanol facility in St. Clair, Ontario, produces ethanol from corn, which is used for blending into our fuels and is also sold to third parties.

As a marketing channel for our Canadian refined products, our Ontario retail networks generated approximately 51% of R&M's Canadian 2007 sales volume of 112,000 bpd. The retail networks are comprised of Sunoco-branded retail service stations, Sunoco-branded Fleet Fuel Cardlock sites, and two 50% retail joint venture[6] businesses that operate Pioneer-branded retail service stations, UPI-branded retail service stations and UPI bulk distribution facilities for rural and farm fuels. Approximately 44% of R&M's Canadian refined product sales in 2007 were wholesale and industrial sales. Sun Petrochemicals Company, a 50% joint venture between a Suncor subsidiary and a Toledo, Ohio-based refinery, generated the remaining 5% of sales.

Our U.S.-based refining and marketing business includes a refining facility, a retail network, and a pipeline transportation business primarily in Colorado and Wyoming. The Commerce City, Colorado refining facility has a current combined crude distillation capacity of 90,000 bpd. The majority of the refined products from the Commerce City refinery are distributed in Colorado.

Approximately 18% of R&M's US petroleum products sales in 2007 (2006 – 18%) were sold through a distribution network in Colorado that sells gasoline and diesel fuel to retail customers. In 2007, approximately 74% (2006 – 74%) of our U.S.-based 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 8% of R&M's U.S. refined product sales volumes for 2007 (2006 – 8%).

In addition to our downstream refining and marketing operations, this business also includes an energy marketing and trading business. Energy marketing and trading activities consist of both third party crude oil marketing, and financial and physical derivatives trading activities.

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[6] Pioneer Group Inc. is an independent company with which Suncor has a 50% joint venture partnership. UPI Inc. is a 50% joint venture company Suncor has with GROWMARK Inc., a Midwest U.S. retail farm supply and grain marketing cooperative.

Procurement of Feedstocks

The Sarnia refinery uses both synthetic and conventional crude oil. In 2007, the Sarnia refinery procured approximately 50% (2006 – 55%) of its synthetic crude oil feedstock from our Oil Sands production. In 2007, 43% (2006 – 60%) 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.

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 Enbridge Pipeline from Montreal. We have not made any firm capacity commitments 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.

In July 2006, with the completion of our ethanol facility, we began producing ethanol for use in our blended gasoline products, and for sales to third parties.

The Commerce City refining operation uses both conventional and synthetic crude oil. Approximately one-quarter of the refinery's crude oil is purchased from Canadian sources, with the remainder supplied from sources in the United States, primarily from 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.

With the completion of our diesel desulphurization and oil sands integration projects, we are now capable of processing of up to 40,000 bpd and 15,000 bpd of Oil Sands sour crude oil at our Canadian and U.S. refineries, respectively.

Refining Operations

Canadian

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.

In 2007 the refinery had capacity to refine 70,000 bpd of crude oil. Refining units include a 23,300 bpd hydrocracker and a 5,400 bpd alkylation unit. The petrochemical facilities have a capacity of 13,100 bpd, the aromatic solvents unit has a capacity of approximately 1,000 bpd, and our gasoline desulphurization unit has the capacity to process 10,250 bpd. The distillate hydrotreater that became operational in July 2006 has a processing capacity of 43,600 bpd.

In 2007 the refinery had cracking capacity of 40,200 bpd from a Houdry catalytic cracker ("catcracker") and a hydrocracker. Approximately 40% of the cracking capacity was attributable to the catcracker, which uses older technology. In 2004, a study to assess the catcracker concluded that, with planned improvements and upgrades, it can continue to be operated economically and safely for at least 10 years.

A range of replacement options for the catcracker was identified during a review in 2005. Analysis of these and other options will continue.

Overall, crude utilization averaged 98% for 2007, compared to 78% in 2006. In 2007 the utilization rate was impacted by a shutdown to tie-in new facilities while in 2006 the utilization rate was impacted by a major maintenance shutdown.

The refinery's external steam and electricity needs are currently being met primarily by supply from the Sarnia Regional Co-generation Project.

United States

Refining units include two fluidized catalytic crackers with a 29,500 bpd combined capacity, a 19,000 bpd distillate hydrotreater and a 26,000 bpd gas oil hydrotreater. The refined gasoline products from the Commerce City refinery primarily supply R&M's marketing operations in Colorado. Refining sales in 2007 averaged approximately 99,600 bpd (15,800 m^3 per day) compared to 90,600 bpd (14,400 m^3 per day) in 2006.

The Commerce City refining operation is a high conversion operation that produces a full range of products, including gasoline, jet fuels, diesel and asphalt. The refinery produces a crude slate containing approximately one-third heavy, high sulphur crude. Overall, crude utilization averaged 99% in 2007 (2006 – 92%).

The following chart sets out R&M's total daily crude input and average refinery utilization rates for both its combined Canadian and U.S. refinery operations in 2007 and 2006.

Total Canadian and U.S. Refinery Capacity	**2007**	**2006**
Average daily crude input (barrels per day)	157,600	136,700
Average crude utilization rate (%)[1]	98	85

Notes:

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

In the normal course of our operations we regularly complete planned maintenance shutdowns of our refinery facilities. These shutdowns are scheduled, and provide both preventative maintenance and capital replacement which is expected to maintain our operational efficiency. During 2007, significant maintenance shutdowns were successfully completed at both our Sarnia and Commerce City area refining facilities.

Principal Products

Set forth below is information on daily sales volumes and the corresponding percentage of R&M's consolidated operating revenues by product for the last two years.

Product:	2007		2006	
	(thousands of cubic meters per day)	(% of R &M's consolidated revenues)	(thousands of cubic meters per day)	(% of R&M's consolidated revenues)
Transportation Fuels				
Gasoline				
Retail	5.2	13	5.3	19
Joint Ventures	3.1	5	3.0	6
Other	8.5	24	7.6	23
Jet Fuel	2.3	4	1.7	4
Diesel	8.3	18	6.8	18
Sub-total – Transportation Fuels	27.4	64	24.4	70
Petrochemicals	0.9	2	0.9	3
Asphalt	1.7	2	1.2	1
Other	3.5	5	3.0	5
Total Refined Products	33.5	73	29.5	79
Other Non-Refined Products(1)		2		2
Energy Marketing & Trading		25		19
Total %		100		100

Note:

(1) Includes ancillary revenues

Principal Markets

Canadian

Approximately 51% (2006 – 58%) of R&M's Canadian sales volumes are marketed through retail networks, including the Sunoco-branded retail network, joint venture owned retail stations and cardlock operations. In 2007, this network was comprised of:

- 272 (2006 – 272) Sunoco-branded retail service stations
- 151 (2006 – 151) Pioneer-operated retail service stations
- 55 (2006 – 53) UPI-operated retail service stations and a network of 13 bulk distribution facilities for rural and farm fuels
- 48 (2006 – 36) Sunoco branded Fleet Fuel Cardlock sites

UPI Inc. is a joint venture company owned 50% with GROWMARK Inc., a U.S. Midwest agricultural supply and grain marketing cooperative. Pioneer is a 50% joint venture partnership with The Pioneer Group Inc.

Refined petroleum products (excluding petrochemicals) are marketed under several brands, including the Company's Canadian "Sunoco" trademark. R&M's other principal trademarks include "Ecowash", our award-winning car wash and "Gold Diesel", our premium low-sulphur diesel product.

Approximately 44% (2006 – 36%) of R&M's Canadian sales volumes are sold to industrial, commercial, wholesale and refining customers, primarily in Ontario. R&M also supplies industrial and commercial customers in Quebec through long-term arrangements with other regional refiners.

R&M Canadian operations market toluene, mixed xylenes, orthoxylene and other petrochemicals, primarily in Canada and the U.S., through Sun Petrochemicals Company. R&M has a 50% interest in Sun Petrochemicals Company, 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. Sun Petrochemicals Company markets petrochemicals used to manufacture plastics, rubber, synthetic fibres, industrial solvents and agricultural products, and gasoline octane enhancers. All benzene production is sold directly to other petrochemical manufacturers in Sarnia, Ontario.

R&M's share of total refined product sales in its primary Canadian market of Ontario was approximately 20% in 2007 (2006 – 18%). Transportation fuels accounted for 78% of R&M's Canadian sales volumes in 2007 (2006 – 82%); and petrochemicals accounted for 5% (2006 – 6%). 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.

Refined petroleum products are also supplied to the Pioneer and UPI joint ventures. We have a separate supply agreement with each of UPI and Pioneer. These supply agreements are evergreen and are subject to termination only in accordance with the terms of the various agreements between the parties.

United States

Approximately 18% of R&M's U.S. sales volumes are marketed through Phillips 66 ® - branded retail outlets. This network is comprised of:

- 44 owned Phillips 66 ® - branded retail sites, which account for approximately 5% of R&M's U.S. sales volumes; and

- Supply agreements with 173 Phillips 66 ® branded marketer outlets throughout the state of Colorado, which account for approximately 13% of R&M's U.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 8% of R&M's U.S. 2007 sales volumes (2006 – 8%).

Approximately 74% of R&M's U.S. sales volumes are sold to industrial, commercial, wholesale and refining customers, primarily in Colorado, of which approximately 10% was sold under a long-term supply agreement with ConocoPhillips (expiring in 2013) and 23% was sold under a supply agreement with Valero (expiring in 2008).

R&M estimates its U.S. sales of total light fuels refined product in 2007 represented a market share, in its primary market of Colorado, of approximately 40% (2006 – 40%). Within this market, R&M's Phillips 66 ® - branded sites represent a 13% market share (2006 – 15%).

Transportation and Distribution

R&M operations use a variety of transportation modes to deliver products to market, including pipeline, water, rail and road.

For our Canadian operations, R&M owns and operates petroleum transportation, terminal and dock facilities, including storage facilities and bulk distribution plants in Ontario. The major mode of transporting gasoline, diesel, jet fuel and heating fuels from the Sarnia refinery to core markets in Ontario is the Sun-

Canadian Pipe Line, which is 55% owned by Suncor and 45% owned by another refiner. The pipeline operates as a private facility for its owners, serving terminal facilities in Toronto, Hamilton and London.

We also have 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 R&M's Canadian operations to move products to market or obtain feedstocks/products when market conditions are favourable in the Michigan and Ohio markets.

For our U.S. operations, approximately sixty percent 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 crude pipeline, the Centennial pipeline, from Guernsey, Wyoming to Cheyenne, Wyoming. Until September 27, 2007, we owned approximately 65% of the Centennial pipeline. Effective September 27, 2007, we purchased the remaining 35% interest from another area refiner, and are now the 100% owner of the Centennial pipeline.

The Rocky Mountain crude system had a capacity of 38,000 bpd in 2007 for the Guernsey to Cheyenne leg of the pipeline and 73,500 bpd for the Cheyenne to Denver leg of the pipeline. In 2007, the Rocky Mountain Crude system utilized approximately 85% (2006 – 81%) of its capacity with average throughput of 27,600 bpd (2006 – 28,200 bpd) in the Guernsey to Cheyenne leg of the pipeline, and 67,700 bpd (2006 - 62,400 bpd) in the higher capacity Cheyenne to Denver leg. During the same period, the Centennial pipeline utilized approximately 80% (2006 – 85%) of capacity, with an average throughput of approximately 50,800 bpd (2006 – 54,400 bpd).

R&M's U.S. operations have both truck and rail loading racks at the Denver area refining facility 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.

In both our Canadian and U.S. operations, 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 R&M business are described under "Competition" in the "Risk Factors" section of this Annual Information Form.

Environmental Compliance

Due to increasingly stringent regulations regarding water discharges, we are required to improve water treatment capability at our Commerce City refining operation, which will require additional water treating equipment for the discharge of process waste water. It is estimated this will cost approximately $44 million to $49 million (US$45 to $50 million) and is expected to be completed in the 2008 to 2010 timeframe. During 2007 we spent approximately $12 million (US $11 million) on the ammonia phase waste water project.

The Ontario provincial, Colorado state and Canadian federal governments are in various stages of developing greenhouse gas management legislation and regulation. At this time, no such legislation has been tabled in any of these jurisdictions and any potential impacts are unknown.

For a discussion of environmental risks at our R&M operations, refer to the "Legal and Regulatory Risks" outlined in the "Risk Factors" section of this Annual Information Form, as well as the "Asset Retirement Obligations" section under "Critical Accounting Estimates" in the "Suncor Overview and Strategic Priorities" section of our MD&A.

MATERIAL CONTRACTS

During the year ended December 31, 2007, 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

As a Canadian issuer, we are subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of our reserves in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). However, we have received an exemption from Canadian securities regulatory authorities 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 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 78.5% for proven reserves, and 80% for proved plus probable reserves. The lower yield rate applied to proven reserves reflects historical operational levels. The 80% proved plus probable reserves yield rate reflects anticipated yield levels once operational performance issues have been addressed.

During 2005, we reached an agreement with the Government of Alberta finalizing the terms of our option to transition to the generic bitumen-based royalty regime commencing in 2009, allowing us to prepare an estimate of our net mining reserves. The estimate of our net mining reserves reflects the value of Alberta Crown, overriding, and freehold royalty burdens under constant December 31 pricing and our exercise of the option electing 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. As there is currently no legislated methodology for determining bitumen value for Alberta Crown royalty purposes, bitumen value for determining royalties has been assumed to correspond to Firebag bitumen sales to our upgrader. However, determination of bitumen value for royalty purposes is currently under review by the Government of Alberta. In October 2007, the Government of Alberta proposed changes to the royalty regime. In January 2008, Suncor entered into a Royalty Amending Agreement to transition to the new royalty framework assuming the government enacts their proposed changes. Neither the governments proposed changes, nor our Royalty Amending Agreement have been reflected in the following reserve estimates. For a full discussion of our Crown royalties, see "Oil Sands Crown Royalties" and "Natural Gas Crown Royalties" in the "Suncor Overview and Strategic Priorities" section of our MD&A.

In addition to reporting our reserves in accordance with U.S. disclosure requirements, the exemption issued by Canadian securities regulatory authorities permits us to provide voluntary additional disclosure. We provide this voluntary additional disclosure to show aggregate proved and probable oil sands reserves, including both mining and Firebag reserves. In our voluntary disclosure we report our aggregate reserves on the following basis:

- Gross and net proved and probable mining reserves are consistent with required US mining disclosures, however the voluntary disclosure reflects 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 CSA Staff Notice 51-315 (reported as barrels of synthetic crude oil based upon a net coker, or synthetic crude oil, yield from bitumen of 78.5% for proved reserves and 80% for proved plus probable reserves); and

- Gross and net proved and probable bitumen reserves from Firebag in-situ leases, evaluated based on Annual Average Differential Pricing. 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% for proved and proved plus probable reserves.

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;

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

(d) are evaluated based on 2007 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.

Comparisons of reserve estimates under “Required U.S. Oil and Gas Mining Disclosure” and “Voluntary Oil Sands Reserve Disclosure” may 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. These differences were significant for 2005 and 2007 reporting given the considerably lower constant price assumptions. At December 31, 2006, there was no difference arising from pricing. Refer to "Voluntary Oil Sands Reserves and Resources Disclosure - Estimated Gross and Net Proved and Probable Oil Sands Reserves Reconciliations".

In addition to our required and voluntary reserves disclosures, we have also elected to disclose our best estimate remaining recoverable resources for both mining and in-situ at December 31, 2007. These disclosures follow the requirements in NI 51-101.

All of our reserves and resources have been evaluated as at December 31, 2007 by independent petroleum consultants, GLJ Petroleum Consultants Ltd. ("GLJ"). In reports dated February 19, 2008 for Oil Sands Mining and February 11, 2008 for Oil Sands In-Situ (collectively referred to herein as "GLJ Oil Sands Reports"), GLJ evaluated our resources and our proved and probable reserves on our oil sands mining and Firebag in-situ leases pursuant to U.S. disclosure requirements using Constant Cost and Pricing assumptions.

Estimates in the GLJ Oil Sands Reports consider recovery from leases for which regulatory applications have been submitted and no 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, project implementation commitments, 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 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 11, 2008 ("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, 2007.

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, capital expenditures, and the current Government of Alberta royalty regime. These assumptions reflect market and regulatory conditions, as required, at December 31, 2007, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory 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, 2006	1,709	1,507	634	564	2,343	2,071
Revisions of previous estimates	(1)	103	106	149	105	252
Extensions and discoveries	-	-	-	-	-	-
Production	(74)	(66)	-	-	(74)	(66)
December 31, 2007	**1,634**	**1,544**	**740**	**713**	**2,374**	**2,257**

Notes:

(1) Synthetic crude oil reserves are based upon a net coker, or synthetic crude oil yield from bitumen of 78.5% for proved reserves, and 80% for proved plus probable reserves. The lower yield rate applied to proved reserves reflects historical operational levels that have fallen below management expectations. The 80% proved plus probable reserves yield rate reflects a return to management's target levels once operational performance issues have been addressed.

(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 value of Crown, freehold and overriding royalty burdens under constant December 31 pricing and incorporates our exercised option to elect to transfer to a bitumen based Crown royalty effective at the beginning of 2009. Neither the current proposed Alberta royalty regime changes, nor our Royalty Amending Agreement have been incorporated. If enacted, at current oil prices we expect our future royalty payments to increase and our net reserves to decrease. Refer to the "Alberta Crown Royalties" risk, as outlined in the "Risk Factors" section of this AIF.

Significant Mining Leases

Interest Held	Description	Gross Acres	Expiry Date (4)	Retention Conditions
Leases:	7279080T19	18,541	n/a	(1)
	7597030T11	2,454	n/a	(1)
	7280100T25	49,365	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)
Permits:	7006060389	8,853	May 31, 2011	(3)
	7006060390	1,897	May 31, 2011	(3)
	7006060391	3,162	May 31, 2011	(3)
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		228,015		

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 terms of the leases. Upon application for continuation prior to the indicated expiry dates, leases can be retained beyond the indicated expiry dates if they meet the minimum level of evaluation and if:

   a) the leases are in production and sustain agreed minimum levels of production; or

   b) escalating rents are paid. Escalating rents start at $7/hectare/year and double every three years to a maximum of $224/hectare/year.

3) Annual rentals are required to maintain these permits until the indicated expiry dates for the terms of the permits. Upon application prior to the indicated expiry dates, a permit can be converted to a 15 year term lease if the minimum level of evaluation criteria has been met. Upon conversion of a permit to a lease, continuation of the resulting lease is as set out in (2) above.

4) There is no undeveloped acreage subject to expiration in each of the next three years.

Oil Sands Mining Operating Statistics

The following table sets out certain operating statistics for our Oil Sands mining operations. Measurements are averages based on measurement statistics throughout the year and accordingly, should be read as approximations. Statistics for the Oil Sands Firebag in-situ operations are addressed under the heading "Proved Conventional Oil and Gas Reserves" and "Sales, Production, Well Data, Land Holdings and Drilling Activity - Conventional".

	2007	**2006**	**2005**
Total mined volume [1]			
millions of tonnes	331.3	356.2	313.7
Mined volume to tar sands ratio[1]	40.6%	41.8%	32.0%
Tar sands mined			
millions of tonnes	134.4	149.0	100.5
Average bitumen grade (weight %)	12.4%	12.8%	12.2%
Crude bitumen in mined tar sands			
millions of tonnes	16.6	19.1	12.3
Average extraction recovery %	92.8%	93.1%	92.6%
Crude bitumen production			
millions of cubic meters[2]	15.4	17.6	11.4
Gross synthetic crude oil produced			
Thousands of barrels per day[3]	235.0	231.9	152.2

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. 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 table 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 reserves 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, 2004	- [3]	8	8	446
Revisions of previous estimates	639	-	639 [5]	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
Revisions of previous estimates	(57)	-	(57) [5]	5
Improved Recovery	340 [6]	-	340	-
Purchases of minerals in place	-	-	-	-
Extensions and discoveries	-	1	1	26
Production	(12)	(1)	(13)	(53)
Sales of minerals in place	-	-	-	(1)
December 31, 2006	903	7	910	426
Revisions of previous estimates	68	-	68 [5]	4
Improved Recovery	99 [6]	-	99	-
Purchases of minerals in place	-	-	-	19
Extensions and discoveries	-	-	-	33
Production	(13)	(1)	(14)	(53)
Sales of minerals in place	-	-	-	(1)
December 31, 2007	1,057	6	1,063	428
Proved Developed				
December 31, 2004	-	7	7	385
December 31, 2005	137	7	144	387
December 31, 2006	188	6	194	365
December 31, 2007	186	6	192	379

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 50.

(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. Since 2005 we have rebooked our proved reserves, and these continued to be economically viable through 2007.

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

(5) Natural gas infill drilling included in total revisions for 2007 was 16 billion cubic feet (bcf), (2006 – 11 bcf; 2005 – 23 bcf).

(6) Improved recovery recognizes a portion of our Firebag Stage 3 expansion project.

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, 2007. We do not have long-term supply agreements or contracts with governments 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)]

	As at December 31,	
($ millions)	**2007**	**2006**
Proved properties	4,896	3,869
Unproved properties	298	224
Other support facilities and equipment	24	22
Total cost	5,218	4,115
Accumulated depreciation and depletion	(1,306)	(1,041)
Net capitalized costs	3,912	3,074

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)]

	For the years ended December 31,		
($ millions)	**2007**	**2006**	**2005**
Property acquisition costs			
Proved properties	140	-	1
Unproved properties	32	29	9
Exploration costs	142	247	148
Development costs	1,459	688	552
Asset retirement obligations	30	35	4
Total capital and exploration expenditures	1,803	999	714

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, 2007	2006	2005
Revenues			
Sales to unaffiliated customers	492	516	670
Transfers to other operations	431	387	52
	923	903	722
Expenses			
Production costs	362	291	213
Depreciation, depletion and amortization	264	215	145
Exploration	93	87	66
Gain on disposal of assets	-	(4)	(12)
Other related costs	47	40	39
	766	629	451
Operating profit before income taxes	157	274	271
Related income taxes	(10)	(38)	(98)
Results of operations	147	236	173

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:

	2007	2006	2005
Year end natural gas price (AECO- $/GJ)	6.26	7.52	10.22
Year end crude oil price (WTI US$/bbl)	95.98	62.09	59.45
Year end light/heavy crude oil differential, WTI at Cushing less LLB at Hardisty (US$/bbl)	41.72	17.99	26.35

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, bitumen valuation methodology, and the impact of future expenditures on unproved properties;

The standardized measure of discounted future net cash flows is determined by using estimated quantities of proved reserves and taking into account the future periods in which they are expected to be developed and produced based on year-end economic conditions. The estimated future production is priced at year-end prices, except that future gas prices are increased, where applicable, for fixed and determinable price escalations provided by contract. The resulting estimated future cash inflows are reduced by estimated future costs to develop and produce the proved reserves based on year-end cost levels. In addition, we have also deducted certain other estimated costs deemed necessary to derive the estimated pretax future net cash flows from the proved reserves including direct general and administrative costs of exploration and production operations and estimated cash flows related to asset retirement obligations. Deducting future income tax expenses then further reduces the estimated pre-tax future net cash flows. 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, reflects 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)	2007	2006	2005
Future cash flows	31,227	32,882	16,444
Future production costs	(15,963)	(12,264)	(10,181)
Future development costs	(8,002)	(5,648)	(1,705)
Other related future costs	(742)	(612)	(464)
Future income tax expenses	(2,203)	(4,221)	(1,216)
Subtotal	4,317	10,137	2,878
*Discount at 10%	(3,807)	(6,768)	(1,214)
Standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves after income taxes	510	3,369	1,664

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)	2007	2006	2005
Balance, beginning of year	3,369	1,664	1,074
Sales and transfers of oil and gas produced, net of production costs	(483)	(559)	(456)
Net changes in prices and production costs	(3,226)	1,907	737
Changes in estimated future development costs	(2,151)	(1,141)	(573)
Extensions, discoveries and improved recovery, less related costs	72	59	162
Development costs incurred during the period	1,459	772	557
Revisions of previous quantity estimates	(4)	1,051	440
Purchases of reserves in place	37	-	-
Sale of reserves in place	(2)	(2)	(4)
Accretion of discount	472	231	125
Net changes in income taxes	934	(714)	(470)
Other related costs	33	101	72
Balance, end of year	510	3,369	1,664

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 Operating Statistics".

Sales Prices[1], [2]

For the year ended December 31,	2007	2006	2005
Crude Oil and Bitumen ($/bbl)…………………………………………………………	37.67	38.94	45.86
NGL ($/bbl)………………………………………………………………………………..	53.32	44.96	50.70
Natural Gas ($/mcf)………………………………………………………………………	6.32	7.15	8.57

Notes:

(1) Production is based in Western Canada.

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

Production Costs

For the year ended December 31,	2007	2006	2005
($ per BOE of gross production)			
Average production (lifting) cost of conventional crude oil and gas[1]	13.63	11.92	10.86

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. These costs represent a blended average of our Firebag and Natural Gas lifting costs.

Producing Oil and Gas Wells

As at December 31, 2007	Crude Oil[3]		Natural Gas		Total	
number of wells	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
Alberta	71	56	399	238	470	294
British Columbia	19	8	143	65	162	73
Total	90	64	542	303	632	367

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, 2007

(thousands of acres)	Developed		Undeveloped[1]		Total	
	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
Canada						
Natural Gas	690	410	1,250	680	1,940	1,090
Firebag	2	2	287	287	289	289
Total Canada	692	412	1,537	967	2,229	1,379
USA						
Natural Gas	-	-	46	24	46	24
Total	692	412	1,583	991	2,275	1,403

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, 2007

(number of net wells)	Net Exploratory			Net Development		
	Productive	Dry Holes	Total	Productive	Dry Holes	Total
Canada						
Natural Gas	7	4	11	14	1	15
Firebag	-	-	-	26	-	26
United States	-	-	-	-	-	-
Total	7	4	11	40	1	41

For the year ended December 31, 2006

(number of net wells)	Net Exploratory			Net Development		
	Productive	Dry Holes	Total	Productive	Dry Holes	Total
Canada						
Natural Gas	3	6	9	14	4	18
Firebag	-	-	-	8	-	8
United States	-	-	-	-	-	-
Total	3	6	9	22	4	26

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

At December 31, 2007, we were participating in the drilling of 28 gross (16 net) exploratory and development wells.

Future Commitments to Sell or Deliver Crude Oil and Natural Gas

We have entered into a number of natural gas sale commitments aggregating approximately 64 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.

As at March 4, 2008 crude oil hedges totaling 10,000 bpd of production were outstanding for the remainder of 2008. Prices for these barrels are fixed within a range of US$59.85 to US$101.06 per barrel. In addition, we have also purchased $60 USD WTI put options for calendar years 2009 and 2010 for volumes of 55,000 bpd. We intend to consider additional costless collars of up to approximately 30% of our crude oil planned production if strategic opportunities are available. For further particulars of these 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 7 to our 2007 Consolidated Financial Statements, which note is incorporated by reference herein.

VOLUNTARY OIL SANDS RESERVES AND RESOURCES DISCLOSURE

Oil Sands Mining and Firebag In-Situ Reserves Reconciliation

The following tables set out, on a gross[7] and net basis, a reconciliation of our proved and probable reserves of synthetic crude oil from our Oil Sands mining leases and bitumen, converted to synthetic crude oil for comparison purposes only, from our in-situ Firebag leases, from December 31, 2006, to December 31, 2007, based on the GLJ Oil Sands Reports.

Estimated Gross Proved and Probable Oil Sands Reserves Reconciliation

	Oil Sands Mining Leases(1)(2)			**Firebag In-situ Leases(1)(3)**			**Total Mining and In-situ(3)**
(millions of barrels of synthetic crude oil)(1)	**Proved**	**Probable**	**Proved & Probable**	**Proved(3)**	**Probable(3)**	**Proved & Probable**	**Proved & Probable**
December 31, 2006	1,709	634	2,343	803	1,907	2,710	5,053
Revisions of previous estimates	(1)	106	105	(17)	(5)	(22)	83
Improved recovery	-	-	-	80	(66)	14	14
Extensions and discoveries	-	-	-	-	-	-	-
Production	(74)	-	(74)	(11)	-	(11)	(85)
December 31, 2007	1,634	740	2,374	855	1,836	2,691	5,065

7 Suncor's working interest in reserves, before deducting Crown royalties, freehold and overriding royalty interests.

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, 2006	1,507	564	2,071	722	1,639	2,361	4,432
Revisions of previous estimates	11	108	119	(15)	(7)	(22)	97
Improved recovery	-	-	-	72	(60)	12	12
Extensions and discoveries	-	-	-	-	-	-	-
Production	(66)	-	(66)	(11)	-	(11)	(77)
December 31, 2007	1,452	672	2,124	768	1,572	2,340	4,464

Notes:

(1) Synthetic crude oil reserves are based upon a net coker, or synthetic crude oil yield from bitumen of 78.5% for proven reserves, and 80% for proved plus probable reserves under Oil Sands mining leases and 80% for both proved reserves and proved plus probable reserves for Firebag in-situ leases. Virtually all of our bitumen from the Oil Sands mining leases is upgraded into synthetic crude oil. However, we have the option of selling the bitumen produced from our Firebag in-situ leases directly to the market where strategic opportunities exist. 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 based on 2007 Annual Average Differential Pricing assumptions in accordance with CSA Staff Notice 51-315 and reflects our exercised option to elect to transfer to a bitumen-based Crown royalty effective at the beginning of 2009. Neither the current proposed Alberta royalty regime changes, nor our Royalty Amending Agreement have been incorporated.

(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;

(c) 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.

(d) are evaluated based on 2007 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.

Remaining Recoverable Resources

Suncor holds a 100% interest in its oil sands leases, all located near Fort McMurray in the Athabasca region of Alberta. Based upon independent evaluations conducted by GLJ effective December 31, 2007, our best estimate of remaining recoverable synthetic crude oil resources, and the components included in the summation, are as follows (billions of barrels):

	Mining	In-Situ	Total
Proved plus probable reserves	2.4	2.6	5.0
Best estimate contingent resources	4.2	6.3	10.5
Best estimate remaining recoverable resources	6.6	8.9	15.5

The Contingent resources are not classified as reserves due to the absence of a commercial development plan that includes a firm intent to develop within a reasonable timeframe, and in some cases due to higher uncertainty as a result of lower core-hole drilling density. Our Voyageur South development area, for which we submitted a regulatory application in 2007, is part of our mining contingent resources. Significant mining contingent resources are also associated with our Audet leases, locate north of our Firebag leases and immediately adjacent to leases proposed for mining development by other operators. All of our in-situ leases are associated with our Firebag leases. While we consider the contingent resources to be potentially recoverable under reasonable economic and operating conditions, there is no certainty that it will be commercially viable to produce any portion of them.

SUNCOR EMPLOYEES

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

	as at December 31, 2007	as at December 31, 2006
Oil Sands	3,612	3,182
Natural Gas	159	170
Refining & Marketing	1,151	1,068
Corporate[2]	1,543	1,346
Total [1]	6,465	5,766

Notes:

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

(2) Corporate employees includes employees from our Major Projects group, which supports all three of our business units.

The Communications, Energy and Paperworkers Union Local 707 represent approximately 2,100 Oil Sands employees. A new collective agreement with the union was entered into effective May 1, 2007. The terms of the agreement include a wage increase of 7% in the first year and 6% in each of the following two years, as well as an initial lump sum payment.

Employee associations represent approximately 220 of R&M - Canada's Sarnia refinery, London terminal and Sun-Canadian Pipe Line Company employees. During 2005, a three year agreement was signed with the Sarnia employee association that will be renegotiated in 2008. During 2006, a three year agreement was signed with the CAW at the London terminal that will continue year after year unless either party provides written notice at least 30 days prior to the expiry date of the agreement of their intent to terminate or negotiate revisions. Management believes the agreement will be renegotiated on its anniversary. 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 United Steel Workers (USW) union represents approximately 218 employees at R&M's Denver refining facilities. In February 2006, the union voted to merge all workers into a single collective bargaining agreement. The merged contract became effective in March 2006 and will expire in January 2009.

RISK FACTORS

As a company, we identify risks in four principal categories: 1) Operational; 2) Financial; 3) Legal and Regulatory; and 4) Strategic. These categories are defined below, and identified risks have been classified accordingly. Please note, identified risks could relate to multiple risk categories; we have classified risks based on the primary category to which they apply to Suncor.

We are continually working to mitigate the impact of potential risks to our business. This process includes an entity-wide risk review. The internal review is completed annually to help ensure that all significant risks are identified and appropriately managed. Risks appear in no particular order below:

1) Operational Risks – Risks that *directly* affect our ability to continue normal operations within our identified businesses.

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

Operating Hazards and Other Uncertainties. Each of our three principal operating businesses, Oil Sands, NG, 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”, below.

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. 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 costs associated with oil sands resources, delineation of the resources, the costs associated with production, including mine development and drilling 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 in the short term 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 is subject to all of the risks normally inherent in the operation of a refinery, terminals, pipelines and other distribution facilities as well as service stations, including loss 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.

Major Projects. There are certain risks associated with the execution of our major projects, including without limitation, the new coker unit and the Voyageur growth strategy. 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 decline and 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. 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 our significant capital projects in progress, see page 18 of our MD&A, incorporated by reference herein.

Insurance. Although we maintain a risk management program, which includes an insurance component, such insurance may not provide adequate coverage in all circumstances, nor are all such risks insurable. Losses beyond the scope of insurance could have a material adverse impact on the company. In late 2005 we formed a self-insurance entity to provide additional business interruption coverage for potential losses. In 2006, one of our external business interruption service providers discontinued operations. We continue to evaluate options to replace this coverage. Refer to note 11 to our 2007 Consolidated Financial Statements, which is incorporated by reference herein, for further description of our insurance coverage.

In December 2006, insurers impacted by the January 4, 2005 fire at Oil Sands filed a statement of claim against various parties alleged to be potentially responsible, seeking to recover amounts paid to Suncor under our insurance contract. As required by our insurance contract, we are named as Plaintiff. However, the action will not have an impact on the insurance settlements we have already reached with our insurers or on our future revenues.

2) Financial Risks – Risks that affect the compilation, reporting and accuracy of financial results.

Uncertainty of Reserve Estimates. The reserves estimates for our Oil Sands and NG business units included in this AIF 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, yield rates for production of synthetic crude oil from bitumen, 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. 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. Production performance subsequent to the date of the estimate may justify revision, either upward or downward, if material. For these reasons, estimates of the economically recoverable reserves attributable to any particular group of properties, and classification of such reserves based on risk of recovery, prepared by different engineers or by the same engineers at different times, may vary substantially.

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 the Petroleum Exporting Countries and weather, among other things, can affect world oil supply and demand. Our natural gas price realizations 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.

Under our strategic crude oil hedging program, management has approval to fix a price or range of prices for approximately 30% of our total crude oil planned production for specified periods of time. As at March 4, 2008, we had crude oil hedges totaling 10,000 bpd of crude oil for production in 2008. Prices for these barrels are fixed within a range from an average of US$59.85/bbl up to an average of US$101.06/bbl. In addition, we have also purchased $60 USD WTI put options for calendar years 2009 and 2010 for volumes of 55,000 bpd. We intend to consider additional strategic hedging opportunities as they become 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. Our downstream business is sensitive to wholesale and retail margins for its refined products, including gasoline, and 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 R&M can be expected to fluctuate and 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 below noted expansion plans of our competitors could result in an increase in the supply of diesel fuel and weaken margins.

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.

Exchange Rate Fluctuations. Our 2007 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 portion of our sales of refined products are in Canadian dollars. In addition, we have subsidiary operations that are denominated in U.S. dollars, translated to Canadian dollars using the current rate approach, whereby revenues and expenses are recorded at the exchange rate at the time the transaction occurs, and assets and liabilities are translated at the exchange rate at the balance sheet date. Therefore, fluctuations in exchange rates between the U.S. and Canadian dollar may give rise to foreign currency exposure, either favorable or unfavorable, creating another element of uncertainty.

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.

3) Legal and Regulatory Risks – Risks that affect our ability to comply with regulatory and statutory requirements under applicable law.

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 for air pollution (Criteria Air Contaminants) and greenhouse gases, that 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 and the province;
* storage, treatment, and disposal of hazardous or industrial waste;
* the need to reduce or stabilize various emissions to air and withdrawals of and discharges to water;
* issues relating to global climate change, land reclamation and restoration;
* issues relating to the manufacture or use of certain substances;
* reformulated gasoline to support lower vehicle emissions.

Changes in environmental regulation could have an adverse effect on us from the standpoint of product demand, product reformulation and quality, methods of production and distribution costs, and financial results. 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.

Suncor is making progress to address challenges at its in-situ operation, where high emissions have resulted in intervention by both Alberta Environment and the Alberta Energy and Utilities Board. Until regulators can be assured emissions are stable at compliant levels, production at the in-situ operation has been capped at approximately 42,000 barrels of bitumen per day. As a result, commissioning of units to increase the bitumen production capacity of Firebag Stages 1 and 2 by about 35% will be delayed. Suncor's revised outlook reflects this constraint. However, unexpected problems in connection with installation of emission abatement equipment, or unanticipated changes to permits or changes to regulatory requirements may adversely affect our plans for increasing bitumen production capacity of Firebag. Furthermore, we may be subject to further regulatory enforcement action, which may in turn, have an adverse effect on our business.

To mitigate the impact to production, we are examining ways to increase bitumen supply from our mining operations. We are also accelerating the construction of emission abatement equipment, which will result in additional maintenance and capital costs being incurred.

In December 2007, high emissions at our base plant resulted in an order being issued by Alberta Environment. Emissions at the oil sands plant exceeded air quality standards, and accordingly we are upgrading our emission control equipment and reducing discharges to the tailings ponds. In addition, we have introduced processing changes and are undertaking a more comprehensive monitoring program. However, unexpected problems in connection with upgrading our emission control equipment or introducing process changes, or unanticipated changes to permits or changes to regulatory requirements may adversely affect our plans for decreasing emissions at base plant. Any such unexpected problems may lead to further regulatory enforcement action, which may in turn, have an adverse effect on our business.

For Suncor's Oil Sands mining leases 86 and 17, 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, 2006 ($14 million as at December 31, 2006) as security for the estimated cost of our reclamation activity. Since there was no production from Leases 86/17 in 2006 or 2007, the amount of security remains unchanged.

For the Millennium, Steepbank, and North Steepbank mines, we have posted irrevocable letters of credit equal to approximately $227 million with Alberta Environment, representing security for the maximum reclamation liability in the period April 1, 2007 through March 31, 2008. For more information about our reclamation and environmental remediation obligations, refer to "Tailings Management" under "Risk Factors Affecting Performance" and "Asset Retirement Obligations" under "Critical Accounting Estimates" in our MD&A.

A new Mine Liability Management Program (MLMP) is under review by the Province of Alberta. The MLMP would involve increased reporting of progressive reclamation, measurement of MLMP assets against MLMP liabilities and measurement of reserve life. Partial security could be required if reclamation targets are not met and full security may eventually be required.

Over the past few years legislation has been passed in Canada and the United States to reduce allowable levels of sulphur in transportation fuels. For a discussion of projects completed at our R&M operations, see the information under the R&M section of "Narrative Description of the Business", in this AIF. Projects to retrofit existing facilities to comply with these standards are subject to all risks inherent in large capital 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 U.S. operations 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 "Three Year History" in this AIF. The Company is subject to the risk that failure to meet remaining 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.

In addition, our business could be affected by the potential for lawsuits against greenhouse gas emitters, based on links drawn between greenhouse gas emissions and climate change.

Governmental Regulation. The oil and gas industry in Canada and the United States, including the oil sands industry and our downstream segments, 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 and other 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 on satisfactory terms, 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**.**

Land Claims. First Nations peoples have claimed aboriginal title and rights to a substantial portion of Western Canada. 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 or other claims, may have on our Oil Sands or other operations.

Alberta Crown Royalties. The following risk factors could cause royalty expenses to differ materially from current estimates and impact the royalties payable to the Crown:

- Pursuant to the new royalty framework, the government intends to establish a permanent generic “bitumen valuation methodology” (BVM) for determining the “R” related to bitumen. The Crown is consulting with stakeholders and independent advisors with a decision on the methodology anticipated by June 30, 2008 and final determination of such methodology may have an impact on royalties payable to the Crown.

- The government also announced its intention to assess and recommend improvements in the system, structures and resources supporting the collection, verification and reporting of provincial royalties. This assessment is expected to be completed by March 31, 2008 and steps taken by the government thereafter may affect the calculation of royalties; and

- Changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each oil sands project; changes to the Generic Regime by the Government of Alberta; changes in other legislation; and the occurrence of unexpected events.

4) Strategic Risks – Risks that affect our ability to meet long term goals and planning initiatives.

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, we added a second upgrader which provides us with the flexibility to conduct periodic plant maintenance on one operation while continuing production and cash flow generation from the other.

Dependence on Oil Sands Business. The Company's significant capital commitment to further our growth projects at Oil Sands, including 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 2007, the Oil Sands business accounted for approximately 87% (88% in 2006) of our upstream production, 87% (89% in 2006) of our net earnings and 79% (84% in 2006) of our cash flow from operations. These percentages have been determined excluding the corporate and eliminations segment information.

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 our ability to maintain a price hedge against the 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 2007, our average natural gas reservoir decline rate was approximately 24% (2006 – 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[8] is unable 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.

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 projects 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 two 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 the availability and cost 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.

Historically, the industry-wide oversupply of refined petroleum products and the overabundance of retail outlets have kept downward 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 unit participates in new product markets, it could be exposed to margin risk and volatility from either cost and/or selling price fluctuations.

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[8] Refer to "Non GAAP Financial Measures" on page ix of this AIF.
[9] Alberta Government – Talk About Oil Sands

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 of/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, medical facilities, and schools) and a commuting workforce have heightened concerns. Our ability to operate safely and effectively and complete major projects on time and on budget is significantly impacted by these risks. Risks associated with completion of significant capital projects are discussed in “Major Projects” above.

Pipeline Capacity Constraints. With our current expansion plans, combined with several other major capital initiatives scheduled by others in the industry, there are increasing risks associated with pipeline capacity and infrastructure which may negatively affect our sales mix and production levels. This is already evident in the timing and method of delivery of our crude oil products to market, as well as our ability to produce at capacity levels in our NG business.

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.

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.

Reclamation. There are risks associated with our ability to complete reclamation work, specifically reclaiming tailings ponds which contain water, clay and residual bitumen produced through the extraction process. To reclaim tailings ponds, we are using a process referred to as consolidated tailings (CT) technology. At this time, no ponds have been fully reclaimed using this technology. The success of the CT technology 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. Regulatory approval of our North Steepbank mine extension, planned for operation in 2010, is subject to certain conditions related to the performance of CT technology.

Labour Relations. Hourly employees at our Oil Sands facility near Fort McMurray, Alberta, our London, Ontario terminal operation, our Sarnia, Ontario refinery, our Denver, Colorado 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.

U.S. Policies re: Clean Oil. Recently, certain U.S. governmental agencies have indicated their intention to purchase oil and related refined products from conventional sources, rather than from the oil sands, which in their view, is a less environmentally friendly source of oil. Although we continue to focus on mitigating our business impact to air, water and land, widespread implementation of such policies could adversely affect markets for our products.

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, 2007, is derived from our 2007 Consolidated Financial Statements. Our consolidated financial statements for each of the years in the three-year period ended December 31, 2007 have been audited by PricewaterhouseCoopers LLP, Chartered Accountants. The information set forth below should be read in conjunction with our MD&A and our 2007 Consolidated Financial Statements.

	Year ended December 31,		
($ millions except per share amounts)	**2007**	**2006**	**2005**
Revenues	17,933	15,829	11,129
Net earnings	2,832	2,971	1,158
Per common share (undiluted)	6.14	6.47	2.54
Per common share (diluted)	6.02	6.32	2.48
Cash flow from operations	3,805	4,533	2,476
Capital and exploration expenditures	5,415	3,613	3,153

	As at December 31,		
($ millions)	**2007**	**2006**	**2005**
Total assets	24,167	18,759	15,126
Long-term debt	3,811	2,363	2,984
Accrued liabilities and other(1)	1,434	1,214	1,005
Shareholders' equity	11,613	8,952	5,996

Note:

(1) See Note 8 to our 2007 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)	**2007**	**%**	**2006**	**%**
Transportation fuel sales	8,056	45	7,016	44
Crude oil sales	5,124	29	5,199	33
Energy marketing and trading	2,883	16	1,582	10
Other (2)	1,840	10	2,019	13
Total	17,903 (1)	100	15,816 (1)	100

Notes:

(1) Excludes interest income.
(2) Includes net insurance proceeds of $436 million in 2006 (2007 - nil)

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. Our Board of Directors approved an increase in the quarterly dividend to $0.10 per share from $0.08 per share in the second quarter of 2007, and an increase to $0.08 per share from $0.06 per share during the second quarter of 2006.

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

	Year Ended December 31,		
	2007	**2006**	**2005**
Common Shares cash dividends..	$0.38	$0.30	$0.24
Dividends paid in common shares..............................	-	-	-

MANAGEMENT'S DISCUSSION AND ANALYSIS

Our MD&A, dated February 27, 2008, is incorporated by reference herein and forms an integral part of this AIF, and should be read in conjunction with our 2007 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, 2007, a total of 462,782,806 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

Our current long-term debt ratings are A(low) Under Review – Developing by Dominion Bond Rating Service Limited; A3 with a stable trend by Moody’s Investors Service, Inc; and A-, with a stable trend by Standard & Poor’s Rating Services, a division of the McGraw-Hill Companies, Inc.

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 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

2007	**Price Range ($Cdn)**		**Trading Volume**
	High	**Low**	**(000's)**
January	92.85	81.50	43,938
February	88.65	82.29	30,930
March	90.00	79.66	34,616
April	94.20	87.58	27,825
May	96.81	88.39	29,160
June	99.70	91.10	30,799
July	100.67	93.23	31,184
August	97.74	88.72	31,945
September	101.55	92.14	36,572
October	104.15	91.25	42,114
November	108.00	94.59	33,919
December	109.47	94.89	24,200

New York Stock Exchange

2007	Price Range ($US) High	Low	Trading Volume (000's)
January	77.35	69.39	43,617
February	75.37	70.25	25,738
March	77.79	67.78	26,717
April	82.89	75.71	22,857
May	89.43	79.81	25,577
June	93.52	85.59	21,554
July	96.41	87.45	22,516
August	92.44	82.37	21,372
September	100.11	88.83	20,197
October	109.49	91.40	24,598
November	117.98	94.56	20,548
December	111.31	94.70	13,011

DIRECTORS AND EXECUTIVE OFFICERS

Directors

The following individuals are directors of Suncor.

Name and Municipality of Residence	Period Served and Independence	Principle Occupations During Past Five Years
Mel E. Benson (3)(4) Calgary, Alberta	Director since 2000 Independent	Mel Benson is president of Mel E. Benson Management Services Inc., an international management consulting firm based in Calgary, Alberta. In 2000 Mr. Benson retired from a major international oil company. Mr. Benson is a partner in Kanetax Energy Inc., Tenax Energy Inc. and a director of Winalta Homes Inc. He is active with several charitable organizations including Hull Family Services and the Canadian Aboriginal Professional Association. He is also a member of the Board of Governors for the Northern Alberta Institute of Technology and the National Aboriginal Economic Development Board.
Brian A. Canfield (1)(2) Point Roberts, Washington	Director since 1995 Independent	Brian Canfield is the chairman of TELUS Corporation, a telecommunications company. Mr. Canfield is also a director and chairman of the governance committee of the Canadian Public Accountability Board. Mr. Canfield is a member of the Order of Canada, a member of the Order of British Columbia, and a fellow of the Institute of Corporate Directors.
Bryan P. Davies (3)(4) Toronto, Ontario	Director 1991 to 1996 and since 2000 Independent	Bryan Davies is chairman of the Canada Deposit Insurance Corporation. He is also a director of the General Insurance Statistical Agency and is past superintendent of the Financial Services Commission of Ontario. Prior to that, he was senior vice president, regulatory affairs with the Royal Bank Financial Group. Mr. Davies is also active with a number of not-for-profit charitable organizations.

Name and Municipality of Residence	Period Served and Independence	Principle Occupations During Past Five Years
Brian A. Felesky [(1)(4)] Calgary, Alberta	Director since 2002 Independent	Brian Felesky is counsel to the law firm of Felesky Flynn LLP in Calgary, Alberta. Mr. Felesky also serves as a director on the board and is chair of the audit committee of Epcor Power LP. He is also a member of the board of Precision Drilling Trust and Resin Systems Inc. Mr. Felesky is actively involved in not-for-profit and charitable organizations. He is the co-chair of Homefront on Domestic Violence, vice chair of the Canada West Foundation, member of the senate of Athol Murray College of Notre Dame and board member of the Calgary Stampede Foundation. Mr. Felesky is a Queen's Counsel and member of the Order of Canada.
John T. Ferguson[(2)(3)] Edmonton, Alberta	Director since 1995 Independent	John Ferguson is founder and chairman of the board of Princeton Developments Ltd. and Princeton Ventures Ltd. Mr. Ferguson is also a director of Fountain Tire Ltd., the Royal Bank of Canada and Strategy Summit Ltd. In addition, he is a director of the C.D. Howe Institute, the Alberta Bone and Joint Institute, an advisory member of the Canadian Institute for Advanced Research and chancellor emeritus and chairman emeritus of the University of Alberta. Mr. Ferguson is also a fellow of the Alberta Institute of Chartered Accountants.
W. Douglas Ford[(1)(2)] Bonita Springs, Florida	Director since 2004 Independent	W. Douglas Ford was chief executive, refining and marketing for BP p.l.c. from 1998 to 2002 and was responsible for the refining, marketing and transportation network of the company as well as the aviation fuels business, the marine business and BP shipping. Mr. Ford currently serves as a director of USG Corporation and Air Products and Chemicals, Inc. He is also a member of the board of trustees of the University of Notre Dame.
Richard L. George Calgary, Alberta	Director since 1991 Non-independent, management	Richard George is the president and chief executive officer of Suncor Energy Inc. Mr. George is also a director of the U.S. offshore and onshore drilling company Transocean. In 2006, he was selected to serve as a member of the North American Competitiveness Council. In 2007, he became a member of the Calgary Committee to End Homelessness and is currently chair of the 2008 Governor General's Canadian Leadership Conference. Mr. George was named a member of the Order of Canada in 2007.
John R. Huff [(2)(3)] Houston, Texas	Director since 1998 Independent	John Huff is chairman of Oceaneering International Inc., an oil field services company. He is also a director of BJ Services Company, KBR and Rowan Companies Inc. Mr. Huff is a member of the National Petroleum Council, the Houston Museum of Natural Science and St. Luke's Episcopal Hospital System in Houston.
M. Ann McCaig [(3)(4)] Calgary, Alberta	Director since 1995 Independent	Ann McCaig is actively involved with charitable and community activities. She is past co-chair of the Alberta Children's Hospital Foundation which raised $52 million for the new state-of-the-art pediatric facility in Calgary. She is currently chair of the Alberta Adolescent Recovery Centre, a trustee of the Killam Estate, chair of the Calgary Health Trust, a director of the Calgary Stampede Foundation and honourary chair of the Alberta Bone and Joint Institute. She is also chancellor emeritus of the University of Calgary and a member of the Order of Canada.

Name and Municipality of Residence	Period Served and Independence	Principle Occupations During Past Five Years
Michael W. O'Brien(1)(2) Canmore, Alberta	Director since 2002 Independent	Michael O'Brien served as executive vice president, corporate development, and chief financial officer of Suncor Energy Inc. before retiring in 2002. Mr. O'Brien serves on the board of Shaw Communications Inc. and is an advisor to CRA International. In addition, he is past chair of the board of trustees for Nature Conservancy Canada, past chair of the Canadian Petroleum Products Institute and past chair of Canada's Voluntary Challenge for Global Climate Change.
Eira M. Thomas (1)(4) West Vancouver, British Columbia	Director since 2006 Independent	Eira Thomas has been chief executive officer of Stornoway Diamond Corporation, a mineral exploration company, since July 2003. Previously, Ms. Thomas was president of Navigator Exploration Corporation and chief executive officer of Stornoway Ventures Ltd. She is also a director of Strongbow Exploration Inc. and Fortress Minerals Corp. In addition, Ms. Thomas is a director of the University of Toronto (U of T) Alumni Association, Lassonde Advisory Board of the U of T, Prospectors and Developers Association of Canada and the Northwest Territories and Nunavut Chamber of Mines. She also is a member of the U of T President's Internal Advisory Council.

(1) Audit Committee

(2) Board Policy, Strategy Review & Governance Committee

(3) Human Resources and Compensation Committee

(4) Environment, Health & Safety Committee

Executive Officers

The following individuals are the executive officers of Suncor.

Name and Municipality of Residence	Office[(1)(2)]
J. KENNETH ALLEY Calgary, Alberta	Senior Vice President and Chief Financial Officer
MIKE M. ASHAR Calgary, Alberta	Executive Vice President, Strategic Growth and Energy Trading
KIRK BAILEY Fort McMurray, Alberta	Executive Vice President, Oil Sands
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, Refining and Marketing
JAY THORNTON Calgary, Alberta	Senior Vice President, Business Integration
STEVEN W. WILLIAMS Calgary, Alberta	Chief Operating Officer

Note:

(1) Offices shown are positions held by the officers in relation to businesses of Suncor Energy Inc. and its subsidiaries. On a legal entity basis, Mr. Ashar is president of Suncor Energy Marketing Inc. and Mr. Ryley is president of Suncor Energy Products Inc., each of which are Suncor's Canada-based downstream subsidiaries; and Mr. Nabholz, Ms. Lee and Mr. Thornton are officers of Suncor Energy Services Inc., which provides major projects management, human resources and communication, business integration and other shared services to the Suncor group of companies.
(2) This information reflects the positions of officers as at December 31, 2007.

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.

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

Additional Disclosure for Directors and Executive Officers

To the best of our knowledge, having made due inquiry, we confirm that, as at the date hereof:

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

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

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

(c) became bankrupt or made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than Mr. Ford, a director of Suncor who is currently a director of USG Corporation, which was in bankruptcy protection until June, 2006, and who was also a director of United Airlines (until February 2006) which was in Chapter 11 bankruptcy protection until February, 2006.

(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

Fees payable to PricewaterhouseCoopers LLP in 2006 and 2007 are detailed below.

($)	2007	2006[1]
Audit fees	1 440 000	1 719 000
Audit-related fees	448 000	295 000
Tax fees	2 000	–
All other fees	–	3 000
Total	1 890 000	2 017 000

(1) Certain prior period comparative figures have been reclassified to conform to current period presentation.

The nature of each category of fees is described below.

<u>Audit Fees</u>
Audit fees were paid for professional services rendered by the auditors for the audit of Suncor's annual financial statements or services provided in connection with statutory and regulatory filings or engagements.

<u>Audit-related Fees</u>
Audit-related fees were paid for professional services rendered by the auditors for preparation of reports on specified procedures as they relate to joint venture audits, attest services not required by statute or regulation, and membership fees levied by the Canadian Public Accountability Board.

<u>Tax Fees</u>
Tax fees were paid for international tax planning, advice and compliance.

<u>All Other Fees</u>
Fees disclosed under "All Other Fees" were paid for subscriptions to auditor-provided and supported tools.

None of the services described under the captions "Audit-related Fees", "Tax Fees" and "All Other Fees" were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

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 AIF.

Audit Committee Charter

The Audit Committee Charter is attached as Schedule "B" to this AIF.

Composition of the Audit Committee

The Audit Committee is comprised of Mr. Canfield (Chairman), Mr. Felesky, Mr. Ford, Mr. O'Brien and Ms. Thomas. All members are independent and financially literate. The education and expertise of each member is described under the heading "Directors and Executive Officers".

For the purpose of making appointments to the Company's Audit Committee, and in addition to the independence requirements, all directors nominated to the Audit Committee must meet the test of financial literacy as determined in the judgment of the board of directors. Also, at least one director so nominated must meet the test of financial expert as determined in the judgment of the board of directors. The designated financial expert on the Audit Committee is Michael W. O'Brien.

Financial Literacy

Financial literacy can be generally defined as the ability to read and understand a balance sheet, an income statement and a cash flow statement. In assessing a potential appointee's level of financial literacy, the board of directors must evaluate the totality of the individual's education and experience including:

- The level of the person's accounting or financial education, including whether the person has earned an advanced degree in finance or accounting;

- Whether the person is a professional accountant, or the equivalent, in good standing, and the length of time that the person actively has practised as a professional accountant, or the equivalent;

- Whether the person is certified or otherwise identified as having accounting or financial experience by a recognized private body that establishes and administers standards in respect of such expertise, whether that person is in good standing with the recognized private body, and the length of time that the person has been actively certified or identified as having this expertise;

- Whether the person has served as a principal financial officer, controller or principal accounting officer of a corporation that, at the time the person held such position, was required to file reports pursuant to securities laws, and if so, for how long;

- The person's specific duties while serving as a public accountant, auditor, principal financial officer, controller, principal accounting officer or position involving the performance of similar functions;

- The person's level of familiarity and experience with all applicable laws and regulations regarding the preparation of financial statements that must be included in reports filed under securities laws;

- The level and amount of the person's direct experience reviewing, preparing, auditing or analyzing financial statements that must be included in reports filed under provisions of securities laws;

- The person's past or current membership on one or more audit committees of companies that, at the time the person held such membership, were required to file reports pursuant to provisions of securities laws;

- The person's level of familiarity and experience with the use and analysis of financial statements of public companies; and

- Whether the person has any other relevant qualifications or experience that would assist him or her in understanding and evaluating the corporation's financial statements and other financial information and to make knowledgeable and thorough inquiries whether:

- The financial statements fairly present the financial condition, results of operations and cash flows of the corporation in accordance with generally accepted accounting principles; and

- The financial statements and other financial information, taken together, fairly present the financial condition, results of operations and cash flows of the corporation.

Audit Committee Financial Expert

An "Audit Committee Financial Expert" means a person who, in the judgment of the corporation's board of directors, has the following attributes:

a. an understanding of Canadian generally accepted accounting principles and financial statements;

b. the ability to assess the general application of such principles in connection with the accounting for estimates, accruals, and reserves;

c. experience preparing, auditing or analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by Suncor's financial statements, or experience actively supervising one or more persons engaged in such activities;

d. an understanding of internal controls and procedures for financial reporting; and

e. an understanding of audit committee functions.

A person shall have acquired the attributes referred to in items (a) through (e) inclusive above through:

a. education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that involve the performance of similar functions;

b. experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions;

c. experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or

d. other relevant experience.

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, 2007, using constant dollar cost and pricing assumptions as of a point in time, namely December 31, 2007, 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, 2007; 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, 2007, 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 NI 51-101 and had not been relying on the terms of the Decision Document, we would have been required to report the following:

- proved and probable working interest oil and gas reserve quantities relating to oil and gas operations, gross and net, using forecast prices and costs for each of proved developed producing reserves, proved developed non-producing reserves, proved undeveloped reserves, proved reserves (in total), probable reserves (in total) and proved plus probable reserves (in total); and

- future net revenue attributable to the reserves categories referred to above, estimated using forecast prices and costs, before and after deducting future income tax expenses, calculated without discount and using discount rates of 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.

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 2007 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. Information contained in or otherwise accessible through our website does not form part of this AIF, and is not incorporated into the AIF by reference.

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, 2007 using constant dollar cost and pricing assumptions as of a point in time, namely December 31, 2007, 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, 2007; and

(c) proved and probable working interest oil and gas reserve quantities relating to Firebag in-situ leases, estimated as at December 31, 2007 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
Chairman of the Board of Directors

"BRIAN A. CANFIELD"

BRIAN A. CANFIELD
Chairman of the Audit Committee

March 3, 2008

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, 2007. 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, 2007 using constant dollar cost and pricing assumptions as of a point in time, namely December 31, 2007, 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, 2007; and proved and probable working interest oil reserves quantities relating to Firebag in-situ leases, estimated as at December 31, 2007 using constant dollar cost and pricing assumptions.

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, 2007:

		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 11, 2008	Canada	$1,108 million (94%)	$75 million (6%)	$1,183 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, 2007 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.

ORIGINALLY SIGNED BY

Dana B. Laustsen, P. Eng.
Executive Vice-President

Calgary, Alberta, Canada
March 3, 2008