

SUNCOR ENERGY INC.

ANNUAL INFORMATION FORM

March 2, 2009

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" mean 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 thousand cubic feet:1 barrel ratio. BOEs may be misleading, particularly if used in isolation. The BOE conversion ratio of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Bitumen/Heavy Crude Oil

A naturally occurring viscous mixture, consisting mainly of pentanes and heavier hydrocarbons, 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.

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.

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

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

Feedstock

In the oil sands business, feedstock generally refers to raw bitumen required in the production of synthetic crude oil. In the downstream business segment, feedstock refers to 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 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

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 25, 2009, accompanying its audited consolidated financial statements, notes and auditors' report, as at and for the three years in the period ended December 31, 2008.

Natural Gas

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

Natural Gas Liquids

Those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

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.

Reservoir

A porous and permeable subsurface rock formation that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterized by a single pressure system.

Synthetic Crude Oil (SCO)

A mixture of hydrocarbons derived by upgrading crude bitumen from oil sands; may contain sulphur or other non-hydrocarbon compounds and has many similarities to crude oil. Sour synthetic crude oil is produced from oil sands that requires only partial upgrading and contains a higher sulphur content than sweet synthetic crude oil. Sweet synthetic crude oil is produced from oil sands consisting of a blend of hydrocarbons resulting from thermal cracking and purification of bitumen.

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 well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

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.

Certain other terms used in this AIF but not defined herein are defined in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (“NI 51-101”) and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

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 AIF may produce small differences from reported amounts.
- (2) Some information in this AIF is set forth in metric units and some in imperial units.

CURRENCY

All references in this AIF to dollar amounts are in Canadian dollars unless otherwise indicated.

FORWARD-LOOKING STATEMENTS

This AIF 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: market instability affecting Suncor's ability to borrow in the debt capital markets at acceptable rates; availability of third party bitumen; success of our hedging strategies; maintaining a desirable debt to cash flow ratio; 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 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 review of the unintended consequences of the proposed New 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 in "Risk Factors", and throughout this AIF and in our MD&A. 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 to our 2008 Consolidated Financial Statements mean Suncor's audited consolidated financial statements prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), the notes and the auditors' report, as at and for the three years in the period ended December 31, 2008.

NON-GAAP FINANCIAL MEASURES

Certain financial measures referred to in this AIF that are not prescribed by GAAP, namely, cash flow from operations, cash and total operating costs per barrel and return on capital employed ("ROCE"). These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. We include cash flow from operations (dollars and per share amounts), cash and total operating costs per barrel data and ROCE because investors may use this information to analyze operating performance, leverage and liquidity. The additional information should not be considered in isolation or as a substitute for measures of performance prepared in accordance with Canadian GAAP.

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, May 2002, and May 2008, 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 petroleum products at our refinery in Sarnia, Ontario. Refined products and petrochemicals are marketed 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, natural gas liquids, sulphur, and crude volumes produced by, and purchased from, our natural gas business unit. Suncor Energy Marketing Inc. 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, located near Fort McMurray, Alberta, produces bitumen recovered from oil sands through mining and in-situ technology and upgrades it into refinery feedstock, diesel fuel and 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, natural gas liquids, oil and by-products from reserves primarily in western Alberta and northeastern British Columbia. The sale of natural gas production offsets natural gas purchased for internal consumption at our oil sands operations.

Our refining and marketing business refines crude oil at Suncor's refineries in Sarnia, Ontario, and Commerce City, Colorado, into a broad range of petroleum and petrochemical products and produces ethanol at our plant in St. Clair, Ontario for blending into fuels. These products are then marketed to industrial, commercial and retail customers principally in Ontario 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. The refining and marketing business also encompasses third-party energy marketing and trading activities, and provides marketing services for the sale of crude oil, natural gas, refined products and by-products from the oils sands and natural gas segments.

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 and Eliminations" segment. This includes the activity of our self-insurance entity, as well as investments in wind energy.

In 2008, we produced approximately 264,700 boe per day, comprised of 228,000 barrels per day (bpd) of crude oil from our oil sands operations, and 220 million cubic feet equivalent per day (mmcf/d) of natural gas and liquids from our natural gas business. In 2007, the most recent period with published results, we were the largest crude oil and natural gas liquids producer in the country (approximately 9%¹ of Canada's crude oil production in 2007) and were also Canada's 16th largest natural gas producer.²

In 2008, our refining and marketing business sold approximately 198,100 bpd or 31,500 m³ per

¹ 2008 Canadian Crude Oil Forecast and Market Outlook – Appendix B.1

² Oilweek – July 2008, Top 100 Oil and Gas Producers

day of refined products, mainly in Ontario and Colorado, but also in other parts of the United States and in Europe.

Three-Year History

Oil Sands

Over the past three years we have continued to advance our multi-phased growth strategy to increase production capacity. Key milestones and significant events that have affected our oil sands business during this time period include the following:

- 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, 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. In January 2008, we entered into the Suncor Royalty Amending Agreement (the "Amending Agreement") with the government of Alberta, which modifies the rates under the Government of Alberta's recently enacted New Royalty Framework (the "New Royalty Framework") which would otherwise apply to our base mining operations. Under the Amending Agreement, prior to January 1, 2010, we would pay a royalty in respect of our base operations at 25% of the difference between a project's annual gross revenues net of related allowable transportation costs (R), less allowable costs (C) including allowable capital expenditures (the R-C Royalty), subject to a minimum royalty of 1% of R. In addition, the Amending Agreement provides Suncor with certainty for various matters, including the bitumen valuation methodology, allowed cost, royalty in-kind, and certain taxes. Under the New Royalty Framework enacted in December 2008, royalty rates will move to a sliding scale royalty of 25% - 40% of R-C, subject to minimum royalty of 1% - 9%, depending on oil price. In both cases, the sliding scale royalty would move with an increase in WTI prices from Cdn\$55/bbl to the maximum rate at Cdn\$120/bbl. From 2010 through 2015 royalty rates on our base mining operations are those in the New Royalty Framework, with a cap of 30% of R-C and a minimum royalty of 1.0% to 1.2% of R. In 2016 and subsequent years, the royalty rates for all of our oil sand operations (our base mining project and our Firebag in-situ project) will be the rates prescribed under the New Royalty Framework, unless it is amended or superseded prior to that time.
- Voyageur South Extension of Mine – In July 2007, Suncor filed a regulatory application for the Voyageur South extension of mine. Bitumen produced at the proposed project is expected to provide additional feedstock flexibility once operational.
- 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.
- Coker Unit – A \$2.3 billion expansion to one of two oil sands upgraders was completed in 2008. This new set of cokers is intended to increase design capacity by 90,000 bpd to a total of 350,000 bpd. Production in 2009 is targeted at 300,000 bpd (+ 5%/-10%).

- Regulatory Requirements
 - In September 2007, high emissions at our Firebag in-situ operations resulted in orders being issued by both Alberta Environment and the Alberta Energy and Utilities Board that capped production. The production cap was lifted on July 22, 2008 after Suncor demonstrated the ability to meet emissions restrictions.
 - 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, 2008, Suncor had spent approximately \$7.0 billion on our planned \$20.6 billion Voyageur growth strategy (comprised of \$11.6 billion targeted for construction of a third upgrader and \$9.0 billion for expanding bitumen supply at our Firebag in-situ operation), which involves the expansion of our Firebag in-situ operations and the construction of a third upgrader. Other current work includes construction of a naphtha unit intended to enhance product mix (60% complete at December 31, 2008), the Firebag Sulphur Plant intended to support our emissions abatement plan (55% complete at December 31, 2008) and the Steepbank Extraction Plant which is expected to improve operational performance (70% complete at December 31, 2008). On January 20, 2009, Suncor's Board of Directors approved a revised capital budget which deferred the company's growth projects in light of recent market conditions. Suncor plans to complete the Steepbank Extraction Plant and Firebag Sulphur Plant, while placing all other growth projects in "safe mode" until market conditions improve. For further discussion of our significant capital projects, see page 14 of our MD&A.

The following changes to our oil sands business have occurred, or are expected to occur in 2009:

- Petro-Canada Agreement – Incremental bitumen to feed the expanded oil sands upgrader commenced January 1, 2009 under a processing agreement between Suncor and Petro-Canada. Under the terms of the agreement, we will process an average of 27,000 bpd of Petro-Canada bitumen on a fee-for-service basis. Petro-Canada retains ownership of the bitumen which is processed into sour crude oil product 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.
- Steepbank Extraction Plant and Firebag Sulphur Plant – We are targeting completion of the Steepbank Extraction Plant and the Firebag Sulphur Plant during 2009.

The material factors used to develop target completion dates and cost estimates are: current capital spending plans, the current status of procurement, design and engineering phases of the projects, updates from third parties on delivery of services and goods associated with the project, and estimates from major project teams on completion of future phases of the project. We have assumed that commitments from third parties will be honored and that material delays and increased costs related to the risk factors referred above will not be encountered. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please see "Risk Factors – Major Projects" in this AIF.

Natural Gas

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

- 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.
- Divestment of non-core assets – In May 2008, we disposed of Arctic properties for proceeds of \$24 million.
- Offshore Permit - In September 2008, Suncor, together with a partner, successfully bid for a large offshore parcel in the Newfoundland and Labrador Offshore Area. This land is adjacent and complementary to an existing holding in the Bjarni area and provides Suncor with a long-term option for future potential natural gas growth. In order to retain the lands, the exploration license requires Suncor to commit to spend net \$30 million in exploration work on the lands within six years.

Refining and Marketing

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

- Reduced Refinery Air Emissions – In connection with the acquisition of a 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 enables 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 construction of our St. Clair ethanol facility at a 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, of which \$2 million has been repaid to date.
- Diesel Desulphurization and Oil Sands Integration – In November 2007, Suncor completed a multiphase three-year \$950 million project at the Sarnia refinery with a 120-

day shutdown to complete the tie-ins. 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. During 2008, additional equipment improvements were identified that will be required before the refinery can achieve full benefit from these modifications. We are currently evaluating our options relating to these capital expenditures.

- The observed performance of our Sarnia refinery in 2008, after completion of our diesel desulphurization and oil sands integration project in 2007, has enabled us to upwardly revise our nameplate capacity to 85,000 bpd from the previously disclosed 70,000 bpd. Starting January 1, 2009, refinery utilization will be calculated using the 85,000 bpd capacity. The Commerce City refining capacity has also been increased from 90,000 bpd to 93,000 bpd effective January 1, 2009.

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.

NARRATIVE DESCRIPTION OF THE BUSINESS

Oil Sands

Suncor produces a variety of refinery feedstock, diesel fuel and by-products by developing our resource leases in 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 2008, represent a significant portion of our 2008 cash flow from operations³ (86%), net earnings (95%) and capital employed³ excluding major projects in progress (68%). These percentages have been determined excluding the corporate and eliminations segment information.

Operations

Our integrated oil sands business involves four operations located near Fort McMurray, Alberta.

- 1) Bitumen is supplied from a combination of open mining operations, in-situ operations and third-party supply.
- 2) Primary extraction facilities recover the bitumen from the mined oil sands ore. In in-situ operations, primary extraction occurs in the ground. Both mined and in-situ bitumen also undergoes secondary extraction processes in preparation for upgrading.
- 3) Heavy oil upgrading converts bitumen into crude oil products. Since late 2005, we have upgraded bitumen from Firebag, with only a small portion of non-upgraded production being strategically sold directly into the market.
- 4) Required utilities (water, steam and electricity) are generated through facilities on site, some owned and operated by Suncor, and others 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 either transported to fixed sizing and extraction plants or fed directly to a mobile sizing and extraction operation at the mine face. In the primary extraction process, bitumen is separated from the oil sands ore using a hot water process. After the final removal of impurities and minerals during secondary extraction, naphtha is added to dilute the bitumen to facilitate transportation to upgrading.

In-Situ - Our in-situ operation (Firebag) uses an extraction technology called Steam Assisted Gravity Drainage ("SAGD") to separate 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 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 back to 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.

³ Refer to "Non-GAAP Financial Measures" on page 6 of this AIF.

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 recovered from both in-situ 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.

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 may utilize new mining technology and processes in our future mine development plans.

While there is virtually no finding costs associated with oil sands resources, delineation of the resources, costs associated with production including mine development and drilling wells for SAGD operations, and 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. Natural gas is used 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. In May 2008, a planned shutdown of Upgrader 1 was undertaken to provide both preventative maintenance and capital replacement to improve operational efficiency.

Principal Products

Sales of light sweet synthetic crude oil and diesel represented 45% of oil sands consolidated operating revenues in 2008, compared to 60% in 2007. The other significant component of our revenues were light sour synthetic crude oil and bitumen sales of 46% (2007 – 39%). Set forth below is information on daily sales volumes and the corresponding percentage of oil sands operating revenues by product for each of the last two years.

Product:	2008		2007	
	(thousands of barrels per day)	(% of operating revenues)	(thousands of barrels per day)	(% of operating revenues)
Light sweet crude oil / diesel	96.8	45	126.7	60
Light sour crude oil / bitumen	130.2	46	108.0	39
Total	227.0		234.7	

We anticipate that approximately 50% of oil sands sales volumes in 2009 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.

We have a transportation service agreement on the Enbridge Athabasca Pipeline for a term that commenced in 1999 and extends to 2028. Total line capacity is 600,000 bpd. Under this agreement, our current pipeline commitment is 182,000 bpd for the transportation of synthetic crude oil and diluted bitumen from Fort McMurray, Alberta to Hardisty, Alberta.

We are a founding member of the Waupisoo pipeline that went into service on June 1, 2008. Under this agreement, our founding member status is for a minimum term of 25 years with options to extend. Total line capacity is 350,000 bpd with potential expansion to 535,000 bpd. Under this agreement our current pipeline commitment is 30,000 bpd for the transportation of synthetic crude oil and diluted bitumen from Cheecham to Edmonton, Alberta.

Suncor has entered into long-term service agreements with affiliates of TransCanada Corporation to transport 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. Linefill on the Keystone pipeline is targeted to occur in 2009, with transportation of crude oil expected to commence in early 2010. Our capacity on this pipeline in 2010 will be 25,000 bpd. In 2008, Suncor contracted additional storage facilities at both Patoka and Cushing, in order to provide further flexibility for trading strategies. Both contracts are for 1.1 million barrels of storage and for fixed five-year terms. On January 1, 2009, Suncor contracted storage facilities for an additional one million barrels at Nederland, Texas, for a fixed five-year term.

In 2008, we entered into new commitments for the transportation of crude oil on the Express New pipeline (30,000 bpd starting in 2008) and the Wamsutter pipeline (10,000 bpd expected to start in 2010). We continue to evaluate additional pipeline agreements to support planned increases in production capacity.

Periodically, we also enter into strategic short-term cargo transport agreements to ship synthetic crude oil internationally. 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 purchase 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 air and private road. We anticipate termination of current road access in 2010, and continue to evaluate alternative means of access.

Competitive Conditions

For a discussion of the competitive conditions affecting our oil sands operations, refer to "Competition" in the Risk Factors section of this AIF.

Seasonal Impacts

Severe winter climatic conditions at our oil sands operations 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 2008 total production (2007 – 13%)) of sour crude from our oil sands operation. We began shipping the crude to Flint Hills at Hardisty, Alberta 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. 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.

Effective January 1, 2009 the agreements with Petro-Canada for bitumen processing and sour crude oil supply commenced. As a result and effective January 1, 2009 our agreement to supply up to 30,000 bpd of diluent to Petro-Canada for bitumen blending expired. Under the bitumen processing agreement, we will process an average 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 approximately 22,000 bpd. In addition, under the sour crude oil supply agreement, we will supply up to 26,000 bpd of our proprietary sour crude oil production to Petro-Canada. Both the processing and supply agreements are for a minimum 10-year term.

A portion of our oil sands production is used in our Sarnia and Commerce City refining operations. During 2008, the Sarnia refinery processed approximately 18% (2007 - 7%) of our oil sands crude oil production and the Commerce City refinery processed approximately 4% (2007 – 6%).

There were no customers that represented 10% or more of our consolidated revenues in 2008 or 2007.

Environmental Compliance

For a discussion of environmental risks at our oil sands operations, refer to the "Legal and Regulatory Risks" in the Risk Factors section of this AIF.

Natural Gas

Our natural gas business, based in Calgary, Alberta, explores for, develops and produces conventional natural gas, natural gas liquids, oil and by-products primarily in western Canada, supplying markets throughout North America. The sale of this production provides a natural price hedge for natural gas purchased for internal consumption at our oil sands operations.

Our exploration program is primarily 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 (northwest Alberta).

Marketing, Pipeline and Other Operations

We operate natural gas processing plants at South Rosevear, Pine Creek, Progress and Simonette with a total design capacity of approximately 265 mmcf/d. Our capacity interest in these gas processing plants is approximately 115 mmcf/d. We also have varying undivided percentage ownership interests in natural gas processing plants operated by other companies and processing agreements in facilities where we do not hold an ownership interest.

Approximately 93% of our natural gas production in 2008 was 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 7% of our natural gas production in 2008 was sold under existing contracts to aggregators ("system sales"). Proceeds received by producers under these system 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. and Pan-Alberta Gas.

To provide exposure to the Pacific Northwest and California markets, we have a long-term gas pipeline transportation contract on the TCPL Gas Transmission Northwest Pipeline. Our contract, which started in 1995, is for 40,000 MMBtu/day and expires in 2023.

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. We currently have no pipeline commitments related to the shipment of conventional crude oil.

Principal Products

Sales of natural gas represented 81% (2007 – 89%) of the business unit's consolidated operating revenues in 2008, with 11% (2007 – 10%) comprised of sales of natural gas liquids and crude oil. The remaining 8% (2007 – 1%) related mainly to sales of sulphur by-product. Set forth below is information on daily sales volumes and the corresponding percentage of natural gas's operating revenues by product for the last two years.

Product:	2008		2007	
	(mmcf equivalent per day)	(% of operating revenues)⁽¹⁾	(mmcf equivalent per day)	(% of operating revenues)
Natural gas	202	81	196	89
Crude oil and natural gas liquids	18	11	19	10
Total	<u>220</u>		<u>215</u>	

Note:

(1) The remaining 8% relates mainly to our sales of sulphur by-product.

Competitive Conditions

For a discussion of the competitive conditions affecting the natural gas business unit, refer to "Competition" in the Risk Factors section of this AIF.

Seasonal Impacts

Risks and uncertainties associated with weather conditions and wildlife restrictions can shorten the winter drilling season and can 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 natural gas operations, refer to the "Legal and Regulatory Risks" outlined in the Risk Factors section of this AIF.

Refining and Marketing

Our refining and marketing business consists of downstream operations in Canada and the United States and an energy marketing and trading business.

Our Canadian-based refining and marketing business operates in central Canada. Our refinery in Sarnia, Ontario, has a current crude oil capacity of 85,000 bpd, up from previous capacity of 70,000 bpd as the result of improvements made with the completion of our diesel desulphurization and oil sands integration project in 2007. The plant refines petroleum feedstock from oil sands and other sources into gasoline, distillates, and petrochemicals with the majority of these refined products distributed in Ontario. We also distribute product purchased from third parties. Our ethanol plant in St. Clair, Ontario produces ethanol from corn, which is used for blending into our fuels and is also sold to third parties and has a capacity of 200 million litres per year.

As a marketing channel for Canadian refined products, our Ontario retail networks sold approximately 52% of refining and marketing's total Canadian sales volume in 2008 (2007 – 51%). The retail networks include the Sunoco-branded retail network, joint venture retail and bulk distribution facilities and cardlock operations. Approximately 42% of our Canadian refined product sales in 2008 were wholesale and industrial sales (2007 – 44%). Sun Petrochemicals Company, a joint venture between a Suncor subsidiary and a Toledo, Ohio-based refinery, generated the remaining refined product 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 93,000 bpd, increased from 90,000 bpd previously reported. The majority of the refined products from the Commerce City refinery are distributed in Colorado.

In 2008, approximately 78% (2007 – 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. Approximately 15% of our U.S. petroleum products sales in 2008 (2007 – 18%) were sold through a distribution network in Colorado that sells gasoline and diesel fuel to retail customers. Asphalt sales comprised the remaining 7% of U.S. refined product sales volumes for 2008 (2007 – 8%).

The energy marketing and trading business activities encompasses third-party energy marketing and trading activities, as well as providing marketing services for the sale of crude oil, natural gas, refined products and by-products and the use of financial derivatives.

Procurement of Feedstocks

Canada

The Sarnia refinery processes both synthetic and conventional crude oil. In 2008, 75% (2007 – 43%) of the crude oil refined at the Sarnia Refinery was synthetic crude oil, of which 71% was supplied from our oil sands operations (2007 – 50%). 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.

We continue to 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.

Diesel desulphurization and oil sands integration work at our Sarnia refinery was completed in 2007. During 2008, additional equipment improvements were identified that will be required

before the refinery can achieve full benefit from these modifications. We are currently evaluating our options relating to these capital expenditures.

United States

The Commerce City refining operation processes both conventional and synthetic crude oil. Approximately 10% of the refinery's crude oil is purchased from Canadian sources (2007 – 23%), 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 15,000 bpd of oil sands sour crude oil at our U.S. refining operation.

Refining Operations

Canada

The Sarnia refinery produces a wide range of products, including transportation fuels, heating fuels, liquefied petroleum gases, residual fuel oil, asphalt feedstock and petrochemicals.

The Sarnia refinery has capacity to refine 85,000 bpd of crude oil. Refining units include a 29,000 bpd hydrocracker and a 5,300 bpd alkylation unit. The petrochemical facilities have a capacity of 18,500 bpd and our gasoline desulphurization unit has the capacity to process 10,000 bpd. The distillate hydrotreater that became operational in July 2006 has a processing capacity of 43,600 bpd.

In 2008, the refinery had cracking capacity of 45,600 bpd from a Houdry catalytic cracker ("catcracker"). 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 will continue to be analyzed.

The refinery's external steam and electricity needs are primarily met through the Sarnia Regional Co-generation Project.

In July 2006, with the completion of our St. Clair ethanol facility, we began producing ethanol for use in our blended gasoline products, and for sale to third parties. Production capacity for this facility is 200 million litres per year.

United States

Refining units include two fluidized catalytic crackers with a 27,000 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 our marketing operations in Colorado.

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 utilizes a crude slate

containing approximately one-third heavy, high sulphur crude oil.

The following chart sets out refining and marketing's combined total daily crude input and average refinery utilization rates for both its Canadian and U.S. refinery operations in 2008 and 2007.

Combined U.S. and Canadian Capacity

<u>Total Canadian and U.S. Refinery Capacity</u>	<u>2008</u>	<u>2007</u>
Average daily crude input (barrels per day)	155,600	157,600
Average crude utilization rate (%) ⁽¹⁾	97	98

(1) Based on crude unit capacity of 70,000 bpd for Sarnia and 90,000 bpd for Commerce City 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 2008, a significant maintenance shutdown was successfully completed at our Sarnia refinery, and in 2007 significant maintenance shutdowns were successfully completed at both our Sarnia and Commerce City refining facilities.

Principal Products

Set forth below is information on daily sales volumes and the corresponding percentage of refining and marketing's operating revenues by product category for the last two years.

<u>Product:</u>	<u>2008</u>		<u>2007</u>	
	(thousands of cubic meters per day)	(% of operating revenues)	(thousands of cubic meters per day)	(% of operating revenues)
Transportation Fuels				
Gasoline				
Retail	4.6	7	5.2	13
Joint Ventures	3.0	3	3.1	5
Other	8.3	13	8.5	24
Jet Fuel	2.0	3	2.3	4
Diesel	8.8	14	8.3	18
Sub-total – Transportation	<u>26.7</u>	<u>40</u>	<u>27.4</u>	<u>64</u>
Fuels				
Petrochemicals	0.8	1	0.9	2
Asphalt	1.8	1	1.7	2
Other	2.2	2	3.5	5
Total Refined Products	<u>31.5</u>	<u>44</u>	<u>33.5</u>	<u>73</u>
Other Non-Refined Products ⁽¹⁾		1		2
Energy Marketing & Trading		55		25
Total %		<u>100</u>		<u>100</u>

Note:

(1) Includes ancillary revenues

Principal Markets

Canada

Approximately 52% (2007 – 51%) of our total Canadian sales volumes are marketed through retail networks. In 2008, this network was comprised of:

- 276 Sunoco-branded retail service stations (2007 – 272)
- 159 Pioneer-operated retail service stations (2007 – 151) ⁴
- 52 UPI-operated retail service stations (2007 – 55) ⁵
- 11 UPI-operated bulk distribution facilities for rural and farm fuels (2007 – 13)⁵
- 47 Sunoco branded Fleet Fuel Cardlock sites (2007 – 48)

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

Approximately 42% (2007 – 44%) of refining and marketing's Canadian sales volumes are sold to industrial, commercial, wholesale and refining customers, primarily in Ontario. Refining and marketing also supplies industrial and commercial customers in Quebec through long-term arrangements with other regional refiners.

Refining and marketing 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. We sell our benzene production directly to other petrochemical manufacturers in Sarnia, Ontario.

Refining and marketing's share of total refined product sales in its primary Canadian market of Ontario was approximately 18% in 2008 (2007 – 20%).

Transportation fuels accounted for 83% of our Canadian sales volumes in 2008 (2007 – 78%); and petrochemicals accounted for 6% (2007 – 5%). The remaining volumes included other refined products such as heating fuels, heavy oils and liquefied petroleum gases, and were sold to industrial users and resellers.

Refined petroleum products are also supplied to the Pioneer and UPI joint ventures. We have a separate supply agreement with both 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.

⁴ Pioneer is a 50% joint venture partnership with The Pioneer Group.

⁵ UPI Inc. is a joint venture company owned 50% with GROWMARK Inc., a U.S. Midwest agricultural supply and grain marketing cooperative.

United States

Approximately 78% (2007 – 74%) of refining and marketing's U.S. sales volumes are sold to industrial, commercial, wholesale and refining customers, primarily in Colorado, of which approximately 10% was sold to ConocoPhillips (2007 – 10%) and 18% was sold to Valero (2007 – 23%).

Approximately 15% (2007 – 18%) of our total U.S. sales volumes are marketed through Phillips 66 ® - branded retail outlets. In 2008, this network was comprised of:

- 44 owned Phillips 66 ® - branded retail sites, which account for approximately 5% of refining and marketing's U.S. sales volumes (2007 – 44 sites; 5% of sales volumes)
- Supply agreements with 200 additional Phillips 66 ® branded retail sites throughout Colorado, which account for approximately 10% of our U.S. sales volumes (2007 – 173 outlets; 13% of 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 U.S. refining operation supplied all of its asphalt production to SemMaterials, L.P. until SemMaterials' bankruptcy protection filing in the summer of 2008. Subsequently, we now directly manage the sales of asphalt, which made up 7% of refining and marketing's U.S. 2008 sales volumes (2007 – 8%).

We estimate our U.S. sales of total light fuels refined product in 2008 represented a 36% market share, in its primary market of Colorado (2007 – 40%). Within this market, our Phillips 66 ® - branded sites hold a 7% market share (2007 – 7%).

Transportation and Distribution

Canada

For our Canadian operations, refining and marketing 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 refining and marketing's Canadian operations to move products to market or obtain feedstocks/products when market conditions are favourable in the Michigan and Ohio markets.

United States

For our U.S. operations, approximately 60% of crude oil processed at the Denver refining operation is transported via pipeline, with the remainder supplied via truck. We own and operate the Rocky Mountain Crude pipeline system, which runs from Guernsey, Wyoming to Denver,

Colorado. This is a common carrier pipeline that transports crude for the Denver refinery as well as for other shippers. We also own and operate the Centennial pipeline, which transports crude from Guernsey, Wyoming to Cheyenne, Wyoming.

The Rocky Mountain Crude system had a capacity of 38,000 bpd in 2008 for the Guernsey to Cheyenne leg of the pipeline and 73,500 bpd for the Cheyenne to Denver leg of the pipeline. In 2008, it utilized approximately 43% (2007 – 73%) of its capacity with average throughput of 16,500 bpd (2007 – 27,600 bpd) in the Guernsey to Cheyenne leg of the pipeline, and utilized approximately 85% (2007 - 92%) with average throughput of 62,200 bpd (2007 – 67,700 bpd) in the higher capacity Cheyenne to Denver leg. During the same period, the Centennial pipeline utilized approximately 46% (2007 – 80%) of capacity, with an average throughput of approximately 29,400 bpd (2007 – 50,800 bpd).

Our U.S. operations have both truck and rail loading racks at the Commerce City 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

For a discussion of the competitive conditions affecting our refining and marketing business, refer to "Competition" in the Risk Factors section of this AIF.

Environmental Compliance

For a discussion of environmental risks at our refining and marketing operations, refer to the "Legal and Regulatory Risks" in the Risk Factors section of this AIF.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The statement of reserves data and other oil and gas information outlined below is dated February 6, 2009, with an effective date of December 31, 2008. The preparation date of the information is February 2, 2009.

Disclosure of Reserves Data

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"). Prior to 2008, we had presented our disclosures in accordance with U.S. disclosure requirements under an exemption from Canadian securities requirements which was not renewed by us following our December 31, 2007 annual disclosures. As a result, reserves information presented for comparative years has been restated to comply with NI 51-101, consistent with the presentation format for December 31, 2008 reserve disclosures.

The reserves and contingent resources data set forth below is based upon an evaluation by GLJ with an effective date of December 31, 2008 contained in the GLJ Report dated February 6, 2009. The reserves data summarizes our oil, liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs prior to provision for interest, general and administrative expenses, cost associated with environmental regulations, the impact of any hedging activities or the liability associated with certain abandonment and all well, pipeline, facilities and mine reclamation costs. Future net revenues have been presented on a before and after tax basis. The reserves data conforms with the requirements of NI 51-101. We engaged GLJ to provide an evaluation of proved and proved plus probable reserves and contingent resources. See also "Definitions and Notes to Reserves Data Tables" below.

The company's reserves are located primarily in Alberta and British Columbia, Canada.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in "Definitions and Notes to Reserves Data Tables" in conjunction with the following tables and notes. For more information as to the risks involved, see "Risk Factors – Uncertainty of Reserve and Resource Estimates" in this AIF.

Reserves Data (Forecast Prices and Costs)

Summary of Oil and Gas Reserves as at December 31, 2008

	Oil ⁽¹⁾		Natural Gas		Natural Gas Liquids	
	Working Interest MMbbl	Net MMbbl	Working Interests Bcf	Net Bcf	Working Interest MMbbl	Net MMbbl
<i>Proved Producing</i>						
Conventional	2	2	459	352	5	4
SCO – Mining	1,571	1,335	-	-	-	-
SCO – In-Situ	94	91	-	-	-	-
<i>Total Proved Producing</i>	1,667	1,428	459	352	5	4
<i>Proved Developed Non-Producing</i>						
Conventional	-	-	50	38	-	-
SCO – In-Situ	45	43	-	-	-	-
<i>Total Proved Developed Non-Producing</i>	45	43	50	38	-	-
<i>Proved Undeveloped</i>						
Conventional	-	-	30	24	-	-
SCO – In-Situ	766	658	-	-	-	-
<i>Total Proved Undeveloped</i>	766	658	30	24	-	-
<i>Total Proved</i>						
Conventional	2	2	539	414	5	4
SCO – Mining	1,571	1,335	-	-	-	-
SCO – In-Situ	905	792	-	-	-	-
<i>Total Proved</i>	2,478	2,129	539	414	5	4
<i>Total Probable</i>						
Conventional	1	-	216	153	2	1
SCO – Mining	745	626	-	-	-	-
SCO – In-Situ	1,808	1,506	-	-	-	-
<i>Total Probable</i>	2,554	2,132	216	153	2	1
<i>Total Proved Plus Probable</i>						
Conventional	3	2	755	567	7	5
SCO – Mining	2,316	1,961	-	-	-	-
SCO – In-Situ	2,713	2,298	-	-	-	-
<i>Total Proved Plus Probable</i>	5,032	4,261	755	567	7	5

(1) Represents light and medium oil for our conventional reserves, and synthetic crude oil ("SCO") for our mining and in-situ reserves.

Net Present Value of Future Net Revenues as at December 31, 2008

	Net Present Values of Future Net Revenue BEFORE Income Taxes – Discounted at %/year (\$ millions)					Unit Value Before Income Tax Discounted at 10%/year (\$ millions)	
	0%	5%	10%	15%	20%	\$/Boe	\$/Mcfe
PROVED							
Producing	71,961	47,160	33,186	24,744	19,325	22.28	3.71
Developed Non-Producing	2,356	1,775	1,380	1,103	902	28.05	4.68
Undeveloped	26,833	11,304	4,967	2,085	651	7.50	1.25
Total Proved	101,150	60,239	39,533	27,932	20,878	17.96	2.99
Total Probable	126,456	39,370	14,052	5,140	1,486	6.51	1.08
TOTAL PROVED PLUS PROBABLE	227,606	99,609	53,585	33,072	22,364	12.29	2.05
	Net Present Values of Future Net Revenue AFTER Income Taxes – Discounted at %/year						
	0%	5%	10%	15%	20%		
PROVED							
Producing	55,850	37,013	26,360	19,895	15,724		
Developed Non-Producing	2,005	1,533	1,209	979	809		
Undeveloped	20,009	8,238	3,443	1,264	178		
Total Proved	77,864	46,784	31,012	22,138	16,711		
Total Probable	94,627	29,052	10,008	3,294	538		
TOTAL PROVED PLUS PROBABLE	172,491	75,836	41,020	25,432	17,249		

Total Future Net Revenues as at December 31, 2008 – Undiscounted

(\$ millions)	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Tax	Future Net Revenue After Income Taxes
PROVED								
Producing	167,832	25,474	54,614	15,744	39	71,961	16,111	55,850
Developed Non-producing	4,614	319	1,675	258	6	2,356	351	2,005
Undeveloped	87,029	12,803	33,304	13,743	346	26,833	6,824	20,009
Total Proved	259,475	38,596	89,593	29,745	391	101,150	23,286	77,864
Total Probable	344,459	58,628	119,854	38,872	649	126,456	31,829	94,627
TOTAL PROVED PLUS PROBABLE	603,934	97,224	209,447	68,617	1,040	227,606	55,115	172,491

Future Net Revenue by Production Group as at December 31, 2008⁽¹⁾

Future Net Revenue BEFORE Income Taxes - Discounted at 10%/year			
	\$(millions)	\$/Boe	\$/Mcf
Proved Producing			
Light and Medium Oil	75	32.47	5.41
Natural Gas	1,365	22.19	3.70
<i><u>Non-conventional activities (Oil Sands)</u></i>			
SCO-Mining	2,699	29.74	4.96
SCO-In-Situ	29,047	21.76	3.63
Total Proved Producing	33,186	22.28	3.71
Total Proved			
Light and Medium Oil	76	32.33	5.39
Natural Gas	1,489	20.64	3.44
<i><u>Non-conventional activities (Oil Sands)</u></i>			
SCO-Mining	8,920	11.27	1.88
SCO-In-Situ	29,048	21.76	3.63
Total Proved	39,533	17.96	2.99
Total Proved Plus Probable			
Light and Medium Oil	85	29.58	4.93
Natural Gas	1,838	18.61	3.10
<i><u>Non-conventional activities (Oil Sands)</u></i>			
SCO-Mining	15,522	6.76	1.13
SCO-In-Situ	36,140	18.43	3.07
Total Proved Plus Probable	53,585	12.29	2.05

(1) The estimated future net revenue presented in the tables above do not reflect the fair market value of the reserves. The forecast prices and cost assumptions applied are estimates only, and actual reserve realizations may differ materially.

Definitions and Notes to Reserves Data Tables:

In the tables set forth above in "Disclosure of Reserves Data" and elsewhere in this AIF the following definitions and other notes are applicable:

1. **"Gross"** means:
 - (a) in relation to our interest in production and reserves, our interest (operating and non-operating) before deduction of royalties and without including any royalty interest of us;
 - (b) in relation to wells, the total number of wells in which we have an interest; and
 - (c) in relation to properties, the total area of properties in which we have an interest.

2. **"Net"** means:
 - (a) in relation to our interest in production and reserves, our interest (operating and non-operating) after deduction of royalties obligations, plus our royalty interest in production or reserves;
 - (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and
 - (c) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest we owned.
3. Columns may not add due to rounding.
4. The oil, natural gas liquids and natural gas reserves estimates presented in the GLJ Report are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). A summary of those definitions are set forth below. The synthetic crude oil reserves include our diesel sales volumes, as well as relatively immaterial volumes of bitumen sales.

Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions.

Reserves are classified according to the degree of certainty associated with the estimates.

- (a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- (b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories:

- (c) **Developed reserves** are those 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 (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

- (i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
- (ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- (d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- (a) at least a 90 per cent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) at least a 50 per cent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that 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. Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

5. Forecast prices and costs

These are prices and costs that are generally acceptable as being a reasonable outlook of the future as of December 31, 2008. To the extent that there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a

contract that is likely to be extended, those prices or costs shall be incorporated into the forecast prices.

The forecast cost and price assumptions include increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, as at December 31, 2008, inflation and exchange rates utilized in the GLJ Report were as follows:

Year	Inflation %	Bank of Canada	NYMEX WTI Crude oil at	Light, Sweet Crude	NYMEX Natural Gas	Natural Gas
		Average Noon Exchange Rate \$US/\$Cdn	Cushing Oklahoma \$US/bbl	Oil at Edmonton (40 API, 0.3%S) \$Cdn/bbl	at Henry Hub \$US/mmbtu	at AECO \$Cdn/mmbtu
2009	2.0	0.825	57.50	68.61	7.00	7.58
2010	2.0	0.850	68.00	78.94	7.50	7.94
2011	2.0	0.875	74.00	83.54	8.00	8.34
2012	2.0	0.925	85.00	90.92	8.75	8.70
2013	2.0	0.950	92.01	95.91	9.20	8.95
2014	2.0	0.950	93.85	97.84	9.38	9.14
2015	2.0	0.950	95.73	99.82	9.57	9.34
2016	2.0	0.950	97.64	101.83	9.76	9.54
2017	2.0	0.950	99.59	103.89	9.96	9.75
2018	2.0	0.950	101.59	105.99	10.16	9.95
2019+	2.0	0.950	+2%/yr	+2%/yr	+2%/yr	+2%/yr

The company's weighted average historical prices realized for the year ended December 31, 2008 were \$95.96/bbl for synthetic crude oil, \$8.23/mcf for natural gas, and \$70.89/bbl for natural gas liquids.

6. Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserves categories noted below as at December 31, 2008.

(\$ millions)

	2009	2010	2011	2012	2013	Subtotal	Remainder	Total	10% Discounted
Total Proved	2,138	3,107	1,206	1,247	1,351	9,049	20,695	29,744	13,980
Total Proved Plus Probable	2,866	5,091	3,848	3,358	2,552	17,715	50,902	68,617	24,638

Management currently believes internally generated cash flows, existing credit facilities and access to capital debt markets are sufficient to fund growth plans. There can be no guarantee that funds will be available or that we will allocate funding to develop all of the reserves attributed in the GLJ Report. Failure to develop those reserves would have a negative impact on future cash flow from operating activities.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates and would reduce reserves and future net revenue to some

degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any property uneconomic.

Costs associated with the Voyager upgrader designed to process approximately 245,000 bbl/d of in-situ bitumen, were included only to the extent that the development plan for the Firebag reserves required additional upgrading, as the remaining costs are believed to be related to development of contingent resources. The proved undeveloped and proved plus probable undeveloped Firebag reserves utilize only 40,000 and 175,000 bbl/d, respectively, of the additional design capacity; for approximately 17 and 30 years, respectively.

7. Estimated future well abandonment costs related to reserves wells have been taken into account by GLJ in determining the aggregate future net revenue therefrom.
8. The forecast price and cost assumptions assumed the continuance of current laws and regulations.
9. All factual data supplied to GLJ was accepted as represented. No field inspection was conducted.
10. **The estimates of future net revenue presented in the tables above do not represent fair market value.**

Reconciliation of Changes in Reserves

Reconciliation of Gross Reserves as at December 31, 2008

	Oil ⁽¹⁾			Natural Gas			Natural Gas Liquids		
	Proved (MMbbl)	Probable (MMbbl)	Proved Plus	Proved (Bcf)	Probable (Bcf)	Proved Plus	Proved (MMbbl)	Probable (MMbbl)	Proved Plus
			Probable (MMbbl)			Probable (Bcf)			Probable (MMbbl)
December 31, 2007									
Conventional	2	-	2	573	232	805	6	2	8
SCO - Mining	1,634	740	2,374	-	-	-	-	-	-
SCO - In-Situ	854	1,837	2,691	-	-	-	-	-	-
	<u>2,490</u>	<u>2,577</u>	<u>5,067</u>	<u>573</u>	<u>232</u>	<u>805</u>	<u>6</u>	<u>2</u>	<u>8</u>
Extensions and Improved Recovery									
Conventional	-	-	-	40	-	40	-	-	-
SCO - In-Situ	51	(51)	-	-	-	-	-	-	-
	51	(51)	-	40	-	40	-	-	-
Technical Revisions									
Conventional	-	1	1	(4)	(19)	(23)	-	-	-
SCO - Mining	9	5	14	-	-	-	-	-	-
SCO - In-Situ	11	22	33	-	-	-	-	-	-
	20	28	48	(4)	(19)	(23)	-	-	-
Discoveries									
Conventional	-	-	-	2	2	4	-	-	-
	-	-	-	2	2	4	-	-	-
Economic Factors									
Conventional	-	-	-	1	1	2	-	-	-
	-	-	-	1	1	2	-	-	-
Production									
Conventional	-	-	-	(73)	-	(73)	(1)	-	(1)
SCO - Mining	(72)	-	(72)	-	-	-	-	-	-
SCO - In-Situ	(11)	-	(11)	-	-	-	-	-	-
	(83)	-	(83)	(73)	-	(73)	(1)	-	(1)
December 31, 2008									
Conventional	2	1	3	539	216	755	5	2	7
SCO - Mining	1,571	745	2,316	-	-	-	-	-	-
SCO - In-Situ	905	1,808	2,713	-	-	-	-	-	-
	<u>2,478</u>	<u>2,554</u>	<u>5,032</u>	<u>539</u>	<u>216</u>	<u>755</u>	<u>5</u>	<u>2</u>	<u>7</u>

(1) Represents light and medium oil for our conventional reserves, and SCO for our mining and in-situ reserves.

Note: The presentation of infill drilling under SEC disclosures historically had been classified as a "Technical Revision". Under current NI 51-101 disclosures infill drilling balances are reported as "Extensions and Improved Recovery".

Additional Information Relating to Reserves Data

Undeveloped Reserves

The table below outlines the proved and probable undeveloped reserves, by product type, attributed to the company over the three most recent years specifically, and in aggregate for those beyond three years.

	Units	Prior	2006	2007	2008
Proved Undeveloped					
Oil ⁽¹⁾	MMbbl	450.2	192.0	61.6	62.5
<i>Conventional</i>		0.1	-	0.1	-
<i>SCO - Mining</i>		-	-	-	-
<i>SCO - In-Situ</i>		450.1	192.0	61.5	62.5
Natural Gas	Bcf	63.8	13.8	43.4	7.5
Natural Gas Liquids	MMbbl	0.6	-	0.1	-
Total: Oil Equivalent	MMboe	461.4	194.3	68.9	63.7
Probable Undeveloped					
Oil ⁽¹⁾	MMbbl	2,587.5	-	-	-
<i>Conventional</i>		0.1	-	-	-
<i>SCO - Mining</i>		488.0	-	-	-
<i>SCO - In-Situ</i>		2,099.4	-	-	-
Natural Gas	Bcf	35.3	20.8	70.8	21.4
Natural Gas Liquids	MMbbl	0.2	0.2	0.1	0.1
Total: Oil Equivalent	MMboe	2,593.6	3.6	11.9	3.6

(1) Represents light and medium oil for our conventional reserves and SCO for our mining and in-situ reserves.

Undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

In respect to mining and in-situ reserves, management uses integrated plans to forecast future development of reserves. The detailed plan aligns current production capacity, capital spending commitments and future development for the next 10 years, and is reviewed and updated continuously for internal and external factors affecting planned activity.

In developing our reserves we consider existing facility and gathering system capacity, capital allocation plans and remaining recoverable resources availability. Accordingly, in some cases it will take us longer than two years to develop all of the currently assigned reserves. We plan to develop the majority of the proved undeveloped reserves over the next five years and the majority of the probable undeveloped reserves over the next seven years.

Significant Factors or Uncertainties

The evaluation of reserves is a continuous process, one that can be significantly impacted by a variety of internal and external influences. Revisions are often required resulting from changes in pricing, economic conditions, regulatory changes, and historical performance.

While the above factors, and many others, can be considered, certain judgments and assumptions are always required. As new information becomes available these areas are reviewed and revised accordingly.

For a summary of risks and uncertainties affecting Suncor please refer to "Industry Conditions" and "Risk Factors" in this AIF.

Other Oil and Gas Information

Oil and Gas Properties and Wells

Suncor's oil sands business recovers bitumen through oil sands mining and in-situ development in northern Alberta. Conventional activities are focused on the development and production of natural gas, and natural gas liquids from reserves in western Alberta.

Suncor has no proved non-producing reserves from either of its mining or in-situ reserves. Within conventional reserves, specific properties are capable of producing (primarily gas) but are limited due to pending pipeline connections, or current pipeline capacity and processing restrictions. The majority of these properties have been in their current non-producing state for less than 3 years, and it is anticipated that pipeline constraints will be satisfactorily addressed in the next 2 – 3 years.

A summary of "oil" and "gas" wells for the company's reserves are outlined below:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	74	56	68	64	394	232	33	16
British Columbia	17	7	5	2	145	68	12	6
Total Canada	91	63	73	66	539	300	45	22

Properties with No Attributed Reserves

The company has a total of approximately 3,184,000 acres (net 1,994,000 acres) for current and future development related to its mining, in-situ and conventional properties. The company has rights to explore, develop, and exploit approximately 137,000 net acres that could potentially expire by December 31, 2009. These net acres are entirely attributed to our conventional properties, no land tenure expiries are scheduled to occur for either mining or in-situ properties for 2009.

Forward Contracts

The company has hedged a portion of its forecasted US dollare denominated sales subject to US dollar West Texas Intermediate (WTI) price risk. As of February 10, 2009, we have crude oil

hedges for approximately 125,000 bpd of production from February 1 through December 31, 2009. These volumes are in addition to previously reported options to sell 55,000 bpd at an equivalent WTI floor price of US \$60.00 per barrel from January 1 to December 31, 2009. The combination of the previous options and new fixed-price hedges provides Suncor with an equivalent WTI floor price of about US \$53.50 for approximately 180,000 bpd of production in 2009.

For the full year 2010, we have crude oil hedges for approximately 50,000 bpd at an equivalent WTI floor price of US \$50.00 per barrel and a ceiling price of approximately US \$68.00 per barrel. This program replaces previously reported 2010 options to sell 55,000 bpd at an equivalent WTI floor price of US \$60.00, which was effectively exited by selling similar contracts for gross proceeds to Suncor of approximately \$250 million before tax.

Additional Information Concerning Abandonment and Reclamation Costs

The company completes an annual review of its forecast abandonment and reclamation costs as they relate to our overall corporate operations. The specific estimates established for forecasted abandonment and reclamation costs are based on available information, consistent with that assumed in our long range planning. These estimates consider the nature of all our forecasted abandonment and reclamation costs, where determinable, for our mining, in-situ and conventional operations. Assets with indeterminate lives have been excluded from the company's abandonment and reclamation cost estimates.

At December 31, 2008 Suncor estimated its abandonment and reclamation costs for surface leases, wells and facilities to be approximately \$4.1 billion (discounted at 10% approximately \$1.3 billion). Of this \$4.1 billion total, \$1 billion (approximately 24%) has been deducted as abandonment costs in estimating the future net revenue from reserves. This \$1 billion represents our abandonment obligations for reserve wells (in-situ and conventional activities).

The company anticipates approximately \$630 million of its identified asset retirement obligations to be incurred during the next 3 years.

Tax Horizon

We expect to pay taxes in 2009.

Costs Incurred

The table below summarized the company's capital expenditures related to its reserve activities for the year ended December 31, 2008.

(Reported in millions)

Property Acquisitions	-
Exploration	133
Land	
Proved	-
Unproved	19
Total	19
Development	2,398
Total Capital	22,550

Exploration and Development Activities

The table below outlines the gross and net exploratory and development wells the company participated in during the year ended December 31, 2008. These represent wells from both our in-situ and conventional activities.

	<u>Exploratory Wells</u>		<u>Development Wells</u>	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
CANADA				
Oil	-	-	24	24
Natural Gas	7	5	24	17
Dry	7	4	7	5
Other	-	-	1	-
Total	14	9	56	46

Production Estimates

The table below outlines the volume of the company's production estimated for the year ended December 31, 2009, as is reflected in the estimate of future net revenues disclosed previously under "Reserves Data".

	<u>Oil ⁽¹⁾</u>		<u>Natural Gas</u>		<u>Natural Gas Liquids</u>	
	<u>Working Interest</u>	<u>Net</u>	<u>Working Interest</u>	<u>Net</u>	<u>Working Interest</u>	<u>Net</u>
	Mbbl/day	Mbbl/day	MMcf/day	MMcf/day	Mbbl/day	Mbbl/day
Total Proved	269	263	199	146	2	2
Total Proved Plus Probable	288	281	209	153	3	2

(1) Represents light and medium oil for our conventional reserves and SCO for our mining and in-situ reserves.

Production History

The table below outlines the company's historical production information, by product type, for each of the four financial quarters, and in aggregate as an average daily measure.

	Q1	Q2	Q3	Q4
Synthetic Crude Oil				
Average Production (mmbbl/d)	248.00	174.60	245.60	243.80
Average Price Received (\$/bbl)	96.16	121.12	116.32	61.53
Royalties (\$/bbl)	12.50	8.18	11.02	2.41
Production Costs (\$/bbl)	31.55	50.85	34.00	41.30
Netback	52.11	62.09	71.30	17.82
Natural Gas				
Average Production (mmcf/d)	209.00	205.00	197.00	195.00
Average Price Received (\$/mcf)	7.30	9.62	9.10	6.90
Royalties (\$/mcf)	1.53	2.23	2.35	1.64
Production Costs (\$/mcf)	1.27	1.45	1.60	1.21
Netback	4.50	5.94	5.15	4.05
Natural Gas Liquids				
Average Production (mmbbl/d)	3.30	3.40	2.60	3.10
Average Price Received (\$/bbl)	64.14	86.14	96.88	39.31
Royalties (\$/bbl)	24.64	20.73	24.91	5.32
Production Costs (\$/bbl)	7.61	8.69	9.63	7.26
Netback	31.89	56.72	62.34	26.73

Average daily production for oilsands (mining and in-situ) was 22.8 Mbbbl/day in 2008 and the average daily production volumes by product type for the year ended December 31, 2008 for conventional was:

Conventional	Year Ended December 31, 2008		
	Nat Gas (mmcf/d)	Liquids (mmcfe/d)	Total (mmcfe/d)
Foothills	99	1	100
Northern	65	11	76
Central Alberta	35	6	41
Other	3	0	3
Total	202	18	220

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 on independent evaluations conducted by GLJ effective December 31, 2008, our estimate of remaining recoverable synthetic crude oil resources is as follows:

Remaining Recoverable Resources

As at December 31, 2008

(millions of barrels of SCO)⁽¹⁾

	Mining	In-Situ	Total
Total Proved	1,600	900	2,500
Total Probable	700	1,800	2,500
Total Proved Plus Probable Reserves	2,300	2,700	5,000
Contingent Resources – Best Estimate ⁽²⁾⁽³⁾	3,500	6,500	10,000
Remaining Recoverable Resources (unrisked)⁽⁴⁾	5,800	9,200	15,000

- 1) Numbers in the above table are rounded to the nearest 100 million.
- 2) Contingent resources are 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. There is no certainty that it will be commercially viable to produce the contingent resources.
- 3) Best Estimate is considered to be the best estimate of the quantity 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.
- 4) Remaining recoverable resources (unrisked) are the arithmetic sum of proved and probable reserves and best estimate contingent resources. Suncor has not quantified potentially recoverable volumes from either undiscovered accumulations or its carbonate leases. The contingent resources have not been adjusted for risk based on the chance of development. It is not an estimate of volumes that may be recovered. Actual recovery may be less.

Remaining recoverable resources were 15,500 millions of barrels of SCO at December 31, 2007. The decrease in 2008 was primarily due to additional drilling and modeling for the Audet leases.

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, located north of our Firebag in-situ leases and immediately adjacent to leases proposes 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 operating conditions, there is no certainty that it will be commercially viable to produce any portion of the resources.

The company has not finalized the development basis for these contingent resources. The volumes assume that Suncor continues to treat and upgrade substantially all of its bitumen using current technologies. Future strategic decisions regarding marketability of bitumen versus synthetic crude oil and implementation of new upgrading technologies could impact actual recoveries and product type of the contingent resources.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to export and taxation of oil and natural gas by agreements among the governments of Canada and Alberta, among others, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the company's operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and the company is currently unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing - Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to the markets, the value of refined products, the supply/demand balance, and other contractual terms. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The price of natural gas is also determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m³/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

Although pipeline expansions are ongoing, the pro-rationing of capacity on the inter-provincial pipeline systems can occur from time to time due to pipeline and downstream operating problems that can affect the ability to market western Canadian crude oil and natural gas.

The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States of America, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that were contained in the Canada / United States Free Trade Agreement, which has been in place since October 1988. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. Under NAFTA all three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, any circumstances in which any other form of quantitative restrictions could be imposed is also prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports. NAFTA may become subject to renegotiation and in such event, there can be no guarantees that the company will not face material trade restrictions, including in respect of pricing by NAFTA participants on its oil and gas products.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral freehold owner and the lessee, although production from such lands may be subject to certain provincial taxes. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, depth of well, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the

trend in recent years has been for provincial governments to revise existing incentive programs and royalty structures, which have generally resulted in increases to the amounts of royalties ultimately payable.

The Canadian federal corporate income tax rate levied on taxable income is 22.1% effective January 1, 2007 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement, the federal corporate income tax rate will decrease to 15% in five steps: 19.5% on January 1, 2008, 19% on January 1, 2009, 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 2012.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime, and was followed by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*, which was given Royal Assent on December 2, 2008. The New Royalty Framework and the applicable new legislation became effective on January 1, 2009. Prior to the New Royalty Framework, the amount of conventional oil royalties that were payable was influenced by the oil production, density of the oil, and the vintage of the oil (the "Generic Regime"). Originally, the vintage classified oil was "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it was considered "old oil", and if it was discovered after March 31, 1974 and before September 1, 1992, it was considered "new oil". The Alberta government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 35%. The New Royalty Framework eliminates this classification and establishes new royalty rates for conventional oil, natural gas and oil sands. At that time, the new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the old royalty from 30%-35% applied to the old and new tiers, to up to 50% and with rate caps once the price of conventional oil reaches Cdn\$120 per barrel. The sliding rate formula includes in its calculation the price of oil and well production.

With respect to natural gas, and similar to the conventional oil framework, the royalties outlined in the New Royalty Framework are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches Cdn\$16.59/Gigajoule. The New Royalty Framework determined rate is based on well depth, production rate, gas price and gas quality. Prior to the New Royalty Framework, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, was up to 30% in the case of new natural gas, and up to 35% in the case of old natural gas, depending upon a prescribed or corporate average reference price. In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling, which program became effective January 1, 2009. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well by well basis, to adopt either the new transitional royalty rates or those outlined in the New Royalty Framework. In order to qualify for this program wells must be drilled during the period starting on January 1, 2009 and ending in December 31, 2013. Following this period all new wells drilled will automatically be subject to the New Royalty Framework.

Oil sands projects are now subject to the New Royalty Framework, and regulated by, among others, the *Oil Sands Royalty Regulation, 2009* approved by the Government of Alberta on December 10, 2008. Royalties on our current Firebag In-Situ project were under the 1997 Generic Regime until the end of 2008, and assessed based on bitumen value. In December 2008, the Government of Alberta enacted the New Royalty Framework, which increased royalty rates from the 1997 Generic Regime to a sliding-scale royalty of 25% to 40% of R – C, subject to minimum royalty of 1% to 9% of R, depending on oil price. In both cases, a sliding-scale royalty moves with increases in WTI prices from Cdn\$55\bbl to the maximum rate at a WTI price of Cdn\$120\bbl. Royalty on our base oil sands mining and associated upgrading operations are modified by Crown agreements and assessed on the R - C royalty subject to a minimum royalty as follows: (a) based on upgraded product values until December 31, 2008 with rates at 25% of R - C subject to the 1% minimum royalty of R; (b) commencing January 1, 2009, a bitumen-based royalty applies pursuant to Suncor's exercise of its option to transition to the bitumen-based Generic Regime. The royalty rates will remain at 25% of the R-C, subject to the 1% minimum royalty of R, but will apply to a revised R - C where R will be based on bitumen value and C would exclude substantially all upgrading costs; (c) from January 1, 2010 through December 31, 2015, pursuant to our January 2008 royalty amending agreement with the Government of Alberta, the New Royalty Framework rates described above will apply to the bitumen royalty for current production levels, subject to a cap of 30% of R-C, and a minimum royalty of 1% to 1.2% of R. In addition, the Suncor Royalty Amending Agreement provides Suncor with a level of certainty for various matters, including the bitumen valuation methodology, allowed cost, royalty in kind and certain taxes; and (d) in 2016 and subsequent years, the royalty rates for all of our oil sands operations, our base operations and our Firebag In-Situ project, will be the rates prescribed under the New Royalty Framework, unless as amended or superseded prior to that time.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to encourage the development of deep oil and gas reserves, and these are: (a) a five-year oil program for exploration wells over 2,000 metres that will provide royalty adjustments to offset higher drilling costs and provide a greater incentive for producers to continue to pursue new, deeper oil plays (these oil wells will qualify for up to a \$1 million or 12 months of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program that will replace the existing program in order to encourage continued deep gas exploration for wells deeper than 2,500 metres (the program will create a sliding scale of royalty credit according to depth, of up to \$3,750 per metre). These new programs are to be implemented along with the New Royalty Framework.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program was to be eliminated, effective January 1, 2007. The programs affected by this announcement were: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program introduced was the Innovative Energy Technologies Program (the "IETP") which has a stated objective of promoting the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy decides which projects qualify and the level of support that will be provided. The deadline for the IETP's final round of applications was September 20, 2008. The successful applicants for the first two rounds have been announced, and those for the third round selection are scheduled to be announced in the

first half of 2009. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

The New Royalty Framework includes a policy of "shallow rights reversion". The Government of Alberta stated that it will implement this policy in order to maximize the development of currently undeveloped resources that is consistent with the Government of Alberta's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's stated objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the government and be made available for resale, and in the event of non-productive shallow wells, to sever the rights from shallow zones and encourage increased production from up-hole zones. In December 2008, the Government of Alberta proclaimed an amendment to the *Mines and Minerals Act* (Alberta) with respect to shallow rights reversion. This amendment affects leases issued after January 1, 2009, with phased-in application for leases entered into prior to January 1, 2009.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "EPEA"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "OGCA"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry.

In 2007, the Alberta government introduced the *Climate Change and Emissions Management Amendment Act* (Alberta), which places intensity (emissions per unit of production) limits on facilities emitting more than 100,000 tonnes of cap, carbon dioxide equivalent per year. Suncor's oil sands are subject to this legislation. The act calls for intensity reductions of 12% commencing July 1, 2007

In compliance with this new legislation, Suncor filed applications in December 2007 to establish baseline intensities for our oil sands facility. In March 2009, Suncor must file compliance reports

that show what actions the company took during the year to offset intensities. Compliance options available to Suncor include emission reductions, utilizing offset projects or contributing to a government climate change emission management fund.

For the compliance period of January 1 to December 31, 2008, the compliance costs to Suncor are estimated at between \$7 million and \$8 million. Final costs determined with the company's March 2009 compliance report filing to the province.

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

On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among other things: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

On March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "Updated Action Plan") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The financial impact of these proposals will be dependent on the details of the final legislation. Subsequent to the introduction of the Updated Action Plan, the Canadian federal government committed to implement a North American cap and trade system with the United States, and therefore it is currently not certain that Updated Action Plan will be implemented as proposed or at all.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. For the oil sands, its proposed application will be process-specific, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and in-situ production will have mandatory standards in 2018 that will be based on carbon capture and storage.

The Updated Action Plan is proposed to apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO₂ equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO₂ equivalent per upstream oil and gas facility; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO₂ equivalent per year per facility.

Under the Updated Action Plan four separate compliance mechanisms are proposed in respect of the above targets: Technology Fund contributions, offset credits, clean development credits

and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The proposed contribution rate will increase over time, beginning at \$15 per tonne for the 2010-12 period, rising to \$20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as mentioned above.

The proposed offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either cancel the offset credits or bank them for future use or sale.

Under the Updated Action Plan, it is proposed that regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

There remains uncertainty around the outcome and impacts of climate change and environmental laws and regulations (whether currently in force or proposed laws and regulations as described herein or future laws and regulations); it is not currently possible to predict either the nature of any requirements or the impact on the company and its business, financial condition, results of operations and cash flow at this time. We continue to actively work to mitigate our environmental impact, including taking action to reduce greenhouse gas emissions, investing in renewable forms of energy such as wind power and biofuels, accelerating land reclamation, installing new emission abatement equipment and pursuing other opportunities such as carbon capture and sequestration.

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.

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

Operating Hazards and Other Uncertainties. Each of our three principal operating businesses, oil sands, natural gas, and refining and marketing, demand significant levels of investment and therefore carry 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 connected with 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 sand and producing bitumen through in-situ methods, extracting bitumen from the oil sands, and upgrading bitumen into synthetic crude oil and other products involve 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 are 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 natural gas operations, including all of the risks normally associated with 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 incidents.

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

Losses resulting from the occurrence of any of these risks could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Major Projects. There are certain risks associated with the execution of our major projects. 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; risks relating to restarting projects placed in "safe mode", including increased capital costs; 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 within our 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. Losses resulting from the occurrence of any of these risks could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Insurance. Our involvement in the exploration for and development of oil and natural gas properties may result in the company becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. 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 effect on our business, financial condition, results of operations and cash flow. 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.

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.

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

2) Financial Risks – Risks that directly affect our business and financial condition.

Capital Markets. Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility in commodity prices and the rates at which we are able to borrow funds for our capital programs. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader Canadian, U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity,

widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions, including higher borrowing rates. Despite the various actions taken by governments around the world, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

As a result of this weakened global economic situation, the company along with all other oil and gas entities will have restricted access to capital and increased borrowing costs. Although our business and asset base have not changed, the lending capacity of all financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, our ability to do so is dependent on, among other factors, the overall state of the capital markets and investor appetite for investments in the energy industry generally and our securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, our ability to make capital investments and maintain existing properties may be impaired, and our business, financial condition, results of operations and cash flow may be materially adversely affected as a result. At December 31, 2008, we had approximately \$3.0 billion of unused credit available under bank credit facilities. Based on current funds available and expected cash from operations, we believe that we have sufficient funds available to fund our currently projected capital expenditures in 2009. However, if cash flow from operations is lower than expected or 2009 capital expenditures exceed current estimates, or if we incur major unanticipated expenses related to development or maintenance of our existing properties, we may be required to seek additional capital to maintain our capital expenditures at planned levels and our debt ratings may be adversely affected. Failure to obtain the financing necessary for our capital expenditure plans may result in a delay in the planned development of production from our operations. This in turn, could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Issuance of Debt. From time to time we may finance capital expenditures in whole or in part with debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the company's articles nor its by-laws limit the amount of indebtedness that we may incur. The level of our indebtedness from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise and could negatively effect our debt ratings. This in turn, could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Debt Covenants. We currently have a \$3.75 billion syndicated credit facility with 16 banks expiring in 2013 and a bilateral credit facility of \$480 million expiring in 2009. We are required to comply with financial and operating covenants under these credit facilities. We routinely review the covenants based on actual and forecast results and have the ability to make changes to our development plans and/or dividend policy to comply with covenants under the credit facilities. In the event that we do not comply with such covenants under the credit facilities, our access to capital could be restricted or repayment could be required, which could have a material adverse effect on our business, financial condition, results of operations and cash flow. In addition, our inability to refinance expiring credit facilities on favorable terms or at all or any restrictions imposed on our borrowings under these facilities due to covenant breaches or otherwise could

have a material adverse effect on our business, financial condition, results of operations and cash flow.

Hedging. From time to time we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, we will not benefit from such increases and we may be obligated to pay royalties on such higher prices, even though not received by us, after giving effect to such agreements. Similarly, from time to time we may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, we will not benefit from the fluctuating exchange rate.

Uncertainty of Reserve and Resource Estimates. The reserves estimates for our oil sands and natural gas 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 and the future net cash flow from these assets 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, the timing and amount of capital expenditures, future royalties, 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. These estimates 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.

In accordance with applicable securities law, our independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flow as summarized herein. Actual future net cash flow will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation and other factors on costs.

Actual production cash flow is derived from our oil and gas reserves and will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated cash flow to be derived from the reserves contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is

effective as of a specific effective date and has not been updated, and thus does not reflect changes in our reserves since that date.

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 have decreased substantially over the last six months. Given the current global economic downturn, we expect continued volatility and uncertainty in crude oil and natural gas prices and prices may remain at depressed levels in the near term and beyond. 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 a material adverse effect on our business, financial condition, results of operations and cash flow. A key component of our business strategy is to target production of sufficient natural gas to meet or exceed internal demands for natural gas purchased for consumption in our oil sands operations, creating a natural price hedge which reduces our exposure to gas price volatility. However, there are no assurances that we will be able to continue to increase production to keep pace with growing internal natural gas demands.

We 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 further or remain at low levels, the carrying value of our assets could be subject to downward revisions, and our earnings could be materially adversely affected.

Volatility of Downstream Margins. Our downstream business is sensitive to wholesale and retail margins for its refined products, including gasoline, diesel and asphalt. Margin volatility is influenced by, among other things, overall marketplace competitiveness, weather, the cost of crude oil (see "Volatility of Crude Oil and Natural Gas Prices" above) 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 our refining and marketing business unit can be expected to fluctuate and may be materially adversely affected.

Energy Trading Activities. The nature of energy trading activities creates exposure to significant financial risks. These include risks that: movements in prices or values could result in a financial loss to the company; a lack of counterparties, due to market conditions or otherwise could leave us unable to liquidate or offset a position, or unable to do so at or near the previous market price; we may not receive funds or instruments from our counterparty at the expected time; the counterparty could fail to perform an obligation owed to us; we may suffer a loss as a result of human error or deficiency in our systems or controls; or we may 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, which may have a material adverse effect on our business, financial condition, results of operations and cash flow.

Exchange Rate Fluctuations. Our 2008 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. 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 favourable or unfavourable, creating another element of uncertainty. To the extent such fluctuation is unfavourable, it may have a material adverse effect on our business, financial condition, results of operations and cash flow.

Dividends. Our payment of future dividends on our common shares will be dependent on, among other things, our financial condition, results of operations, cash flow, the need for funds to finance ongoing operations, debt covenants and other business considerations as the board of directors of the company considers relevant. There can be no assurance that we will continue to pay dividends in the future.

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 manage our interest rate exposures, 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.

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. See "Industry Conditions – Environmental Regulation" in this AIF.

Some of the issues that are or may in future be subject to environmental regulation include:

- the possible cumulative regional impacts of oil sands development;
- manufacture, import, storage, treatment and disposal of hazardous or industrial waste and substances;

- the need to reduce or stabilize various emissions to air;
- withdrawals, use of, and discharges to, water;
- issues relating to land reclamation, restoration and wildlife habitat protection;
- reformulated gasoline to support lower vehicle emissions; and
- U.S. implementation of regulation or policy to limit its purchases of oil to oil produced from conventional sources, or U.S. state or federal calculation and regulation of fuel lifecycle carbon content.

Changes in environmental regulation could have a material adverse effect on us from the standpoint of product demand, product reformulation and quality, methods of production, 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 licenses and permits, which may in turn, have a material adverse effect on our business, financial condition, results of operations and cash flow.

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so called "greenhouse gases". Our exploration and production facilities and other operations and activities emit greenhouse gases and will require us to comply with the new regulatory framework announced on March 10, 2008 by the Federal Government which is intended to force large industries to reduce emissions of greenhouse gases, in addition to the Federal Government's proposed *Clean Air Act* (Alberta) of 2006, Action Plan, Updated Action Plan and Alberta's recently enacted *Climate Change and Emissions Management Act* and *Specified Gas Emitters Regulation*. The direct or indirect costs of these regulations may have a material adverse effect on our business, financial condition, results of operations and cash flow. See "Industry Conditions – Environmental Regulation" in this AIF.

A new reclamation liability management program is under review by the Province of Alberta. The new program would involve increased reporting of progressive reclamation, an asset/liability based risk assessment and consideration 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 refining and marketing operations, see the information under refining and marketing in the "Three-Year History" section of 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 adverse effect on our business, financial condition, results of operations and cash flow.

Our refining and marketing unit's U.S. operations are 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 refining and marketing section of the "Three Year History" section 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 our ability to market our products, potentially having a material adverse effect on our business, financial condition, results of operations and cash flow.

In addition, our business could be materially adversely affected by the potential for lawsuits against greenhouse gas emitters, based on links drawn between greenhouse gas emissions and climate change. See "Industry Conditions – Environmental Regulation" in this AIF.

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 have a material adverse effect on our business, financial condition, results of operations 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 business, financial condition, results of operations and cash flow.

U.S. Policies. The U.S. government has passed legislation that may be interpreted as limiting the purchase of oil and related refined products by governmental agencies to oil and related refined products produced from conventional sources, rather than oil from the oil sands. Although we continue to focus on mitigating our business impact to air, water and land, current and future U.S. environmental laws, regulations and policies may impact or limit our current business plans and/or reduce demand for our products. As a result, our business, financial condition, results of operations and cash flow could be adversely affected.

Land Claims. First Nations peoples have claimed aboriginal title and rights to portions of western Canada. In addition, First Nations peoples have filed claims against industry participants relating in part to land claims, which may affect our business. However, at the present time, we are unable to assess the effect, if any, that these land claims may have on our business.

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:

- The New Royalty Framework has not yet finalized the measurement and valuation of heat transfers between project and non-project assets for integrated operators. The final determination of the business rules for heat transfer may have an impact on future royalties payable to the Crown; 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 New Royalty Framework by the Government of Alberta; changes in other legislation; and the occurrence of unexpected events.

See "Industry Conditions – Royalties and Incentives" in this AIF.

Contractual Obligations. As a result of our reduced capital budget for 2009, we may be unable to fulfill all of our obligations under some of our contractual arrangements which may require us in some cases to pay fees or penalties for cancellation of such contractual arrangements and may result in the company becoming subject to litigation. This in turn, could adversely affect our business, financial condition, results of operations and cash flow.

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

Dependence on Oil Sands Business. Our significant capital commitment to further our growth projects at oil sands 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 2008, the oil sands business accounted for approximately 86% of our upstream production (2007 - 87%), 95% of our net earnings (2007 - 87%) and 86% of our cash flow from operations (2007 - 79%). These percentages have been determined excluding the corporate and eliminations segment information.

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 extension of mine is subject to certain conditions related to the performance of CT technology. Our failure to adequately implement our reclamation plans could have a material adverse effect on our business, financial condition, results of operations and cash flow.

In February 2009, the Energy Resources Conservation Board ("ERCB") released a directive, Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes. The directive establishes performance criteria for CT operations, a requirement for specific approval and monitoring of CT ponds, a requirement for reporting tailings plans, and changes to the ERCB annual mine plan requirements and approval process to regulate tailings operations. We are currently assessing the impact of the directive.

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. Our inability to sufficiently manage these risks could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Need to Replace Conventional Natural Gas Reserves. Future natural gas reserves and production from our natural gas business unit are highly dependent on our successful discovery or acquisition of additional reserves and exploitation of our current reserve base. This has the potential to impact 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 acquisitions, our conventional natural gas reserves and production will decline over time as reserves are depleted. For example, in 2008, our average natural gas reservoir decline rate was approximately 24% (2007 – 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 operations⁶ 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 natural gas 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 primary competition for our crude oil production is other North American conventional and synthetic sweet and sour crude oil producers.

A number of other companies have entered or have indicated their intention to enter the oil sands business and begin producing bitumen and synthetic crude oil or expand their existing operations. While this activity has declined with the corresponding decline in economic conditions, it is expected to resume once there is more market certainty. It is difficult to assess the number, level of production and ultimate timing of all potential new projects or when existing production levels may increase. The Canadian Association of Petroleum Producers estimates that Canada's production of bitumen and upgraded synthetic crude oil could increase from approximately 1.2 million bpd in 2007 to more than three million bpd by 2020⁷. Increasing industry consolidation, a global focus on oil sands and additional competitors with financial capacity has, over the past number of years: (a) materially increased the supply of bitumen and synthetic crude oil and other competing crude oil products in the marketplace; (b) exponentially

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

⁷ Canadian Association of Petroleum Producers' Crude Oil Forecast - Interim Update, 11 December 2008

increased land values and availability of new leases; and (c) placed stress on the availability and cost of all resources required to build and run new and existing oil sands operations. 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.

Labour and Materials Supply. The expansion of the industry up to the third quarter of 2008 and the impact of new entrants to the business, had created the potential for risks related to the availability of, and competition for, skilled labour and materials supply. Although these risks were not exclusive to our oil sands operation, there were increased demands on the Fort McMurray, Alberta infrastructure (for example, housing, roads, medical facilities, and schools). With today's market conditions, these risks have not eroded; rather, with layoffs by some contractors and the corresponding move away from the Fort McMurray region by transient workers, there is a risk that we may have difficulty sourcing the required labour for current and future operations. As well, materials may be in short supply due to smaller labour forces in many manufacturing operations. Our ability to operate safely and effectively and complete all our projects on time and on budget has the potential to be significantly impacted by these risks. Risks associated with completion of significant capital projects are discussed in "Major Projects" above.

Oversupply. In the event that multiple major capital initiatives in the industry proceed simultaneously, there are risks associated with pipeline capacity and infrastructure which could negatively affect our sales mix, and ability to deliver oil sands crudes to Suncor refineries and ultimately crude oil netbacks.

Constraints. Pipeline capacity constraints combined with plant capacity constraints could negatively impact our ability to produce at capacity levels in our crude oil and natural gas business. See "Industry Conditions - Pipeline Capacity".

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, particularly as the results of the technology in real-world applications may differ from test environments. The success of projects incorporating new technologies, such as in-situ technology, cannot be assured.

In-Situ Recovery. 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. While the technology is now being used by several producers, commercial application of this technology is still in the early stages relative to other methods of production and accordingly, in the absence of an extended operating history, there can be no assurances with respect to the sustainability of SAGD operations.

Reliance on Key Personnel. Our success depends in a large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on the company. The contributions of the existing management team to the immediate and near-term operations of the company are likely to continue to be of central importance for the foreseeable future. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business.

Labour Relations. Hourly employees at our oil sands facility near Fort McMurray, Alberta, our London, Ontario terminal operation, our Sarnia, Ontario refinery, our Commerce City, Colorado refinery and at Sun-Canadian Pipeline Company Limited 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 have a material adverse effect on our business, financial condition, results of operations and cash flow.

DIVIDENDS

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 \$0.05 per share* from \$0.04 per share* in the second quarter of 2007, and an increase to \$0.04 per share* from \$0.03 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,		
	2008	2007	2006
Common Shares			
cash dividends.....	\$0.20	\$0.19	\$0.15
Dividends paid in common shares	-	-	-

* Per share amounts have been adjusted to reflect a two-for-one share split in May 2008.

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, 2008, a total of 935,524,213 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) with a Negative Trend by Dominion Bond Rating Service Limited; Baa1 with a Stable Outlook by Moody's Investors Service, Inc; and BBB+ with a Negative Outlook 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 Baa1 by Moody's is the fourth 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 BBB+ by S&P is the fourth 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

Price Range and Trading Volume of Common Shares

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

Toronto Stock Exchange 2008

	Price Range (\$Cdn)		Trading Volume (000's)
	High	Low	
January	56.14	40.92	91,478
February	52.10	45.13	54,787
March	54.73	46.11	72,828
April	61.10	47.78	69,135
May	73.10	53.96	77,431
June	71.25	58.75	79,826
July	62.30	51.32	87,330
August	62.37	51.28	64,491
September	57.21	39.61	114,560
October	43.78	21.85	174,816
November	29.89	18.80	121,190
December	28.14	19.90	100,674

New York Stock Exchange 2008

	Price Range (\$US)		Trading Volume (000's)
	High	Low	
January	56.73	39.67	146,039
February	53.54	44.65	85,771
March	55.54	44.92	111,128
April	60.65	46.31	119,550
May	74.28	52.88	142,737
June	69.94	58.01	109,016
July	61.99	50.80	146,177
August	59.65	49.12	117,861
September	53.95	38.00	194,496
October	41.12	17.83	332,029
November	25.98	14.52	211,059
December	22.99	15.29	177,763

Prior Sales

In May 2008, the company issued 5.80% Medium Term Notes with a principal amount of \$700 million under an outstanding \$2 billion debt shelf prospectus. These notes bear interest at a rate of 5.80% per annum, which is paid semi-annually, and mature on May 22, 2018. The net proceeds were added to our general funds to repay outstanding commercial paper, which originally funded our working capital needs, sustaining capital expenditures and growth capital expenditures.

In June 2008, the company issued 6.10% Notes with a principal amount of US\$1.25 billion and 6.85% Notes with a principal amount of US\$750 million under an amended US\$3.65 billion debt shelf prospectus. These notes bear interest at a rate of 6.10% per annum and 6.85% per annum, respectively, which is paid semi-annually, and mature on June 1, 2018, and June 1, 2039, respectively. The net proceeds were added to our general funds, which are used for our

working capital needs, sustaining capital expenditures, growth capital expenditures and to repay outstanding commercial paper borrowings.

DIRECTORS AND EXECUTIVE OFFICERS

Directors

The following individuals are directors of Suncor.

Name and Jurisdiction of Residence	Period Served and Independence	Principal Occupations During Past Five Years
Mel E. Benson ⁽³⁾⁽⁴⁾ Alberta, Canada	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 director of Tenax Energy Inc., chair of Winalta Homes Inc., director of Tarpon Energy Services and director of the Fort McKay Group of companies. He is active with several charitable organizations including Hull Family Services. He is also a member of the board of governors for the Northern Alberta Institute of Technology.
Brian A. Canfield ⁽¹⁾⁽²⁾ Washington, USA	Director since 1995 Independent	Brian Canfield is the chairman of TELUS Corporation, a telecommunications company. 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⁾ Ontario, Canada	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. Previously, 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.
Brian A. Felesky ⁽¹⁾⁽⁴⁾ Alberta, Canada	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. and various private corporations. Mr. Felesky is 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, board member of the Calgary Stampede Foundation and a council member of the Alberta Order of Excellence. Mr. Felesky is a Queen's Counsel and member of the Order of Canada.

Name and Jurisdiction of Residence	Period Served and Independence	Principal Occupations During Past Five Years
John T. Ferguson ⁽²⁾⁽³⁾ Alberta, Canada	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 and 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 and of the Institute of Corporate Directors.
W. Douglas Ford ⁽¹⁾⁽²⁾ Florida, USA	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 BP 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 Alberta, Canada	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 Swiss offshore and onshore drilling company Transocean. He currently serves as the Canadian chair of the North American Competitiveness Council and he chaired 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⁾ Texas, USA	Director since 1998 Independent	John Huff is chairman of Oceaneering International Inc., an oil field services company. He also serves as director of BJ Services Company, KBR Inc. and Rowan Companies Inc. Mr. Huff is a member of the National Petroleum Council, a trustee of the Houston Museum of Natural Science and is a director of St. Luke's Episcopal Hospital System in Houston.
M. Ann McCaig ⁽³⁾⁽⁴⁾ Alberta, Canada	Director since 1995 Independent	Mrs. McCaig is a trustee of the \$400 million Killam Estate, a director of the Gairdner Foundation, the Chair of the Calgary Health Trust and the Chair of the Alberta Adolescent Recovery Centre, as well as the Honorary Chair of the Alberta Bone and Joint Institute. She is a director of the Calgary Stampede Foundation. She is Chancellor Emeritus at the University of Calgary having served as Chancellor from 1994 to 1998. Mrs. McCaig has received numerous awards including an Honorary Doctor of Laws Degree from the University of Calgary and the University of Alberta, the University of Saskatchewan Alumni Humanitarian Award, the Queen Elizabeth Award, the 125 th Confederation of Canada Award and the Alberta Order of Excellence. She is also a member of the Order of Canada.

Name and Jurisdiction of Residence	Period Served and Independence	Principal Occupations During Past Five Years
Michael W. O'Brien ⁽¹⁾⁽²⁾ Alberta, Canada	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⁾ British Columbia, Canada	Director since 2006 Independent	Eira Thomas assumed the role of executive chairman of Stornoway Diamond Corporation, a mineral exploration company, on January 1, 2009, after serving as chief executive officer 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) Governance Committee
- (3) Human Resources and Compensation Committee
- (4) Environment, Health & Safety Committee

Corporate Officers

The following individuals are the executive officers of Suncor.

Name and Jurisdiction of Residence	Office⁽¹⁾⁽²⁾
J. KENNETH ALLEY Alberta, Canada	Senior Vice President and Chief Financial Officer
MARLOWE ALLISON Alberta, Canada	Vice President and Treasurer
KIRK BAILEY Alberta, Canada	Executive Vice President, Oil Sands
JOEL CROTEAU Alberta, Canada	Senior Vice President, Natural Gas and In Situ Resources
BART DEMOSKY Alberta, Canada	Senior Vice President, Business Services
RICHARD L. GEORGE Alberta, Canada	President and Chief Executive Officer

TERRENCE J. HOPWOOD Alberta, Canada	Senior Vice President and General Counsel
SUE LEE Alberta, Canada	Senior Vice President, Human Resources and Communications
MARK LITTLE Alberta, Canada	Senior Vice President, Strategic Growth and Energy Trading
KEVIN D. NABHOLZ Alberta, Canada	Executive Vice President, Major Projects
JANICE B. ODEGAARD Alberta, Canada	Vice President and Corporate Secretary
JAY THORNTON Alberta, Canada	Executive Vice President, Refining and Marketing
STEVEN W. WILLIAMS Alberta, Canada	Chief Operating Officer

Notes:

- (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. Little is president of Suncor Energy Marketing Inc. and Mr. Thornton is president of Suncor Energy Products Inc., each of which are Suncor's Canada-based downstream subsidiaries; and Mr. Nabholz, Ms. Lee and Mr. Demosky are officers of Suncor Energy Services Inc., which provides major projects management, human resources and communication, business services and other shared services to the Suncor group of companies.
- (2) This information reflects the positions of officers as at December 31, 2008.

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%.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

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

- (a) 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:
 - (i) 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;
 - (ii) 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
 - (iii) 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.

- (b) no director or executive officer of Suncor has:
- (i) 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
 - (ii) 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; and
- (c) 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.

Conflicts of Interest

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.

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,	
	2008	2007
Oil Sands	3,903	3,575
Natural Gas.....	198	196
Refining and Marketing.....	1,112	1,151
Corporate ⁽¹⁾	1,585	1,543
Total ⁽²⁾	6,798	6,465

Notes:

- (1) Corporate employees includes employees from our Major Projects group, which supports all three of our business units.
- (2) In addition to our employees, we also use independent contractors to supply a range of services.

The Communications, Energy and Paperworkers Union Local 707 represent approximately 2,300 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 230 of refining and marketing's Sarnia refinery, London terminal and Sun-Canadian Pipe Line Company employees. In 2008, a four-year agreement that will be renegotiated in 2012 was signed with the Sarnia employee association. In 2006, a three-year agreement was signed with the Canadian Auto Workers union at the London terminal, and expires March 1, 2009. In January 2009, management received formal notification from the Union of its intention to bargain. The agreement with the employee association of Sun-Canadian Pipe Line Company was signed in 1993, and 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 has been received or given to date, and management believes the agreement will be automatically renewed on its anniversary.

The United Steel Workers union represents approximately 250 employees at refining and marketing's Denver refining facilities. In February 2009, the union ratified a 3 year contract which will expire in January 2012.

AUDIT COMMITTEE INFORMATION

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.

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.

Fees Paid to Auditors

Fees payable to PricewaterhouseCoopers LLP in 2008 and 2007 are detailed below:

(\$)	2008	2007
Audit Fees	1,600,000	1,158,000
Audit-Related Fees	442,000	431,000
Tax Fees	7,000	2,000
All other Fees	13,000	-
Total	2,062,000	1,591,000

Prior year numbers have been restated to conform with current year presentation.

The nature of each category of fees is described below.

Audit Fees

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

Audit-Related Fees

Audit-related fees were paid for professional services rendered by the auditors for preparation of reports on specified procedures as they relate to joint venture audits and attest services not required by statute or regulation.

Tax Fees

Tax fees were paid for international tax planning, advice and compliance.

All Other Fees

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

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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 10% of our current assets. In addition, there have not been any (a) penalties or sanctions imposed against the company by a court relating to securities legislation or by a securities regulatory authority during your financial year, (b) penalties or sanctions imposed by a court or regulatory body against the company that would likely be considered important to a reasonable investor in making an investment decision, or (c) settlement agreements entered into by the company before a court relating to securities legislation or with a securities regulatory authority during your financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer, or holder of 10% or more of our 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.

MATERIAL CONTRACTS

During the year ended December 31, 2008, 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, the Shareholder Rights Plan dated April 24, 2008 and the Royalty Amending Agreement dated January 29, 2008 between Suncor and Her Majesty the Queen in Right of Alberta.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by Suncor during, or related to our most recently completed financial year other than GLJ, Suncor's Independent Reserve Engineering Evaluators and PricewaterhouseCoopers LLP, Suncor's auditors. As at the date hereof, none of the principals of GLJ as a group, directly or indirectly, owned more than 1% of our common shares, including the securities of our associates and affiliates, and PricewaterhouseCoopers LLP has advised Suncor's Audit Committee that they are independent with respect to Suncor within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a Canadian issuer listed on the New York Stock Exchange (the "NYSE"), we are not required to comply with most of the NYSE rules and listing standards and instead may comply with domestic requirements. As a foreign private issuer, we are only required to comply with three of the NYSE rules (i) have an audit committee that satisfies the requirements of the United States *Securities Exchange Act of 1934*; (ii) the Chief Executive Officer must promptly notify the NYSE in writing after an executive officer becomes aware of any material non-compliance with the applicable NYSE Rules; and (iii) provide a brief description of any significant differences between our corporate governance practices and those followed by U.S. companies listed under the NYSE. The company has disclosed in the corporate governance section of its website at www.suncor.com that it, in certain instances, it is not required to obtain shareholder approval for material amendments to equity compensation plans and that Suncor, while in compliance with the independence requirements of applicable securities laws in Canada (specifically National Instrument 52-110 *Audit Committees*) and the U.S. (specifically Rule 10A-3 of the *Securities Exchange Act of 1934*), it has not adopted the director independence standards contained in Section 303A.02 of the NYSE's Listed Company Manual. Except as described, the company is in compliance with the NYSE corporate governance standards in all other significant respects.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities, securities authorized for issuance under equity compensation plans 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 2008 Consolidated Financial Statements and MD&A.

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, excluding the Operations Integrity Audit department which is specifically within the mandate of the Environment, Health & Safety Committee (references throughout this mandate to "Internal Audit" shall not include the Operations Integrity Audit department); 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 February 25, 2009

SCHEDULE "C"

FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

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 activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

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 evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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 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 Form 51-101F1 containing reserves data and other oil and gas information;
- (b) the filing of Form 51-101F2 which is the report of the independent qualified reserves Evaluator on the reserves data; and
- (c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

"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 2, 2009

SCHEDULE "D"

**FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR**

Report on Reserves Data

To the board of directors of Suncor Energy Inc. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.

2. 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 carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. 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.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2008, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate, million dollars)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	February 6, 2009	Canada	-	53,484	101	53,585

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada,

ORIGINALLY SIGNED BY

James H. Willmon, P. Eng.
Vice-President

Calgary, Alberta, Canada
February 6, 2009