ANNUAL INFORMATION FORM DATED MARCH 3, 2011

SUNCOR ENERGY

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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. References to "legacy Suncor" and "legacy Petro-Canada" refer to the applicable entity prior to the August 1, 2009 effective date of the merger between legacy Suncor and legacy Petro-Canada.

Barrel of oil equivalent (boe)

Suncor converts certain natural gas volumes to barrels (bbls) of oil equivalent (boe), thousands of barrels of oil equivalent (mboe), mboe per day (mboe/d) or millions of barrels of oil equivalent (mmboe) on the basis of one barrel (bbl) to six thousand cubic feet and daily production is presented as barrels of oil equivalent per day (boe/d). Boe, mboe and mmboe may be misleading, particularly if used in isolation. A conversion ratio of one barrel of crude oil or natural gas liquids to six thousand cubic feet of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead.

Bcf

Billions of cubic feet.

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.

Bpd

Barrels per day.

Capacity

Maximum annual average output that may be achieved from a facility in ideal operating conditions in accordance with current design specifications.

Conventional crude oil

Crude oil produced through wells by standard industry recovery methods.

Conventional natural gas

Natural gas produced from all geological strata, including associated, non-associated and solution gas, but excluding coal bed methane and shale gas.

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.

Exploration and Production Sharing Agreements (EPSAs)

See production sharing contracts.

Feedstock

In the oil sands business, feedstock generally refers to raw bitumen required in the production of synthetic crude oil. In the downstream business, feedstock refers to crude oil and/or other components required in the production of refined products.

Field

A defined geographical area consisting of one or more pools containing hydrocarbons.

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.

GBP

The pound sterling, commonly called the pound (£), is the official currency of the United Kingdom.

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.

Mbbls/d

Thousands of barrels per day.

MMbbls

Millions of barrels.

MMbtu

Millions of british thermal units.

Mcf

Thousands of cubic feet.

MMcf/d

Millions of cubic feet per day.

Mcfe or MMcfe

Suncor converts certain crude oil and natural gas liquids volumes to thousands of cubic feet equivalent of natural gas (Mcfe) and millions of cubic feet equivalent of natural gas (MMcfe) on the basis of one barrel to six thousand cubic feet, and daily production is presented as millions of cubic feet equivalent per day (MMcfe/d). Mcfe and MMcfe may be misleading, particularly if used in isolation. A conversion ratio of one barrel of crude oil or natural gas liquids to six thousand cubic feet of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead.

Natural gas

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

Natural gas liquids (NGLs)

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.

Overburden

Material overlying oil sands that must be removed before mining, and that 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.

Production Sharing Contracts (PSCs)

A common type of contract signed between a government and a resource extraction company that states how much of the resource extracted from the country each party will receive and which parties are responsible for the development and operation of the resources. The company conducts its operations in Syria pursuant to PSCs.

An Exploration Production and Sharing Agreement (EPSA) is a form of PSC, which also states which parties are responsible for exploration activities. The company conducts its operations in Libya pursuant to EPSAs.

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.

Steam Assisted Gravity Drainage (SAGD)

An enhanced oil recovery technology for producing heavy crude oil and bitumen. It is an advanced form of steam stimulation in which a pair of horizontal wells are drilled into the oil reservoir, one a few metres above the other. Low pressure steam is continuously injected into the upper wellbore to heat the oil and reduce its viscosity, causing the heated oil to drain into the lower wellbore, where it is pumped out.

Synthetic crude oil (SCO)

A mixture of hydrocarbons derived by upgrading (thermal cracking and purification) of crude bitumen from oil sands that may contain sulphur or other non-hydrocarbon compounds and has many similarities to crude oil. SCO with lower sulphur content is referred to as "sweet" while SCO with higher sulphur content is referred to as "sour".

Utilization

The average use of capacity, taking into consideration planned and unplanned facility outages and maintenance.

Wells

Appraisal well
A well drilled to measure the commercial potential (i.e. size and quality) of a hydrocarbon discovery. Before development, a discovery is likely to need several such wells.

Development or developmental 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 or exploration 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.

West Texas Intermediate (WTI)

A type of crude oil used as a benchmark in oil pricing, WTI is the underlying commodity of futures contracts on the New York Mercantile Exchange (NYMEX).

CONVERSION TABLE[1][2]

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

(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.

PRESENTATION OF INFORMATION

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

FORWARD-LOOKING STATEMENTS

Certain statements contained in this AIF constitute "forward-looking statements" within the meaning of the *United States Private Securities Litigation Reform Act of 1995* and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). All forward-looking statements are based on the company's current expectations, estimates, projections, beliefs and assumptions based on information available at the time the statement was made and in light of the company's experience and its perception of historical trends, including expectations and assumptions concerning the accuracy of reserve and resource estimates; commodity prices and interest and foreign exchange rates; capital efficiencies and cost-savings; applicable royalty rates and tax laws; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour and services; and the receipt, in a timely manner, of regulatory and third-party approvals.

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. Forward-looking statements in this AIF include references to:

- business strategies and goals;
- future investment decisions;
- future capital, exploration and other expenditures;
- future cash flows;
- future resource purchases and sales;
- anticipated construction and repair activities;
- anticipated turnarounds at upgraders, refineries and other facilities;
- anticipated refining margins;
- future oil and natural gas production levels, including anticipated field lives, and the sources of their growth;
- project development and expansion schedules and results;
- future exploration activities and results, and dates by which certain areas may be developed or come on-stream;
- anticipated retail throughputs;
- anticipated pre-production and operating costs;
- reserves and resources estimates;
- future royalties and taxes payable;
- anticipated cost savings, and other synergies, realized from the merger with Petro-Canada;
- production life-of-field estimates;
- natural gas export capacity;
- future financing and capital activities;

- contingent liabilities;
- the impact and cost of compliance with existing and potential environmental regulations;
- future regulatory approvals;
- expected rates of return.

In addition, all other statements that address expectations or projections about the future, including statements about our strategy for growth, commodity prices, costs, schedules, production volumes, operating and financial results, and expected impact of future commitments, are forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, some that are similar to other oil and gas companies and some that are unique to Suncor. Our actual results may differ materially from those expressed or implied by our forward-looking statements, and readers are cautioned not to place undue reliance on them.

The risks, uncertainties and other factors, 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 capital debt markets at acceptable rates; consistently and competitively finding and developing reserves that can be brought on-stream economically; success of hedging strategies; maintaining a desirable debt to cash flow ratio; changes in the general economic, market and business conditions; our ability to finance capital investment to replace reserves or increase processing capacity in a volatile commodity pricing and credit environment; fluctuations in supply and demand for Suncor's products; commodity prices, interest rates and currency exchange; volatility in natural gas and liquids prices; Suncor's ability to respond to changing markets and to receive timely regulatory approvals; the successful and timely implementation of capital projects including growth projects and regulatory projects; risks and uncertainties associated with consulting with stakeholders and obtaining regulatory approval for exploration and development activities in Suncor's operating areas (these risks could increase costs and/or cause delays to or cancellation of projects); effective execution of planned turnarounds; the accuracy of cost estimates, some of which are provided at the conceptual or other preliminary stage of projects and prior to commencement or conception of the detailed engineering needed to reduce the margin of error and increase the level of accuracy; the integrity and reliability of Suncor's capital assets; the cumulative impact of other resource development; the cost of compliance with current and future environmental laws; the accuracy of Suncor's reserve, resource and future production estimates and its success at exploration and development drilling and related activities; the maintenance of satisfactory relationships with unions, employee associations and joint venture partners; competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; 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, our negotiations with the Alberta Department of Energy in respect of the Bitumen Valuation Methodology Regulation; 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 (including in respect of any planned divestitures); risks and uncertainties associated with the ability to meet closing conditions with respect to the sale of any of Suncor's assets, the timing of closing and the consideration to be received with respect to the planned sale of any of Suncor's assets, including the ability of counterparties to comply with their obligations in a timely manner and the receipt of any required regulatory or other third party approvals outside of Suncor's control; the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; failure to realize anticipated synergies or cost savings; risks regarding the integration of the Suncor and Petro-Canada after the merger; and incorrect assessments of the values of Petro-Canada. The foregoing 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 150-6th Avenue S.W., Calgary, Alberta, T2P 3E3, 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 this AIF by reference.

ACCOUNTING MATTERS

References to our "2010 Consolidated Financial Statements" mean Suncor's audited consolidated financial statements prepared in accordance with Generally Accepted Accounting Principles (GAAP), the notes and the auditors' report, as at and for the three-year period ended December 31, 2010. References to our MD&A mean Suncor's Management's Discussion and Analysis, dated February 24, 2011, accompanying the 2010 Consolidated Financial Statements.

On August 1, 2009, Suncor completed its merger with Petro-Canada. As such, the 2009 results reflect those of the post-merger Suncor from August 1, 2009 together with results of legacy Suncor only from January 1, 2009 through July 31,

2009. The comparative figures from 2008 reflect solely the results of legacy Suncor. Additional information about Suncor and legacy Petro-Canada filed with Canadian securities commissions and the United States (U.S.) Securities and Exchange Commission (SEC), including periodic quarterly and annual reports, are available online at www.sedar.gov and our website www.suncor.com.

Certain amounts in prior years have been reclassified to conform to the current year's presentation.

The Canadian Institute of Chartered Accountants Accounting Standards Board confirmed in February 2008 that Canadian publicly accountable enterprises must adopt International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board, effective January 1, 2011. For more information with respect to the company's adoption of IFRS, see the "Changes in Accounting Policies" section of our MD&A.

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.

Pursuant to an arrangement (the Arrangement), which was completed effective August 1, 2009, legacy Suncor and legacy Petro-Canada amalgamated to form a single corporation continuing under the name "Suncor Energy Inc.". The Arrangement was effected pursuant to section 192 of the *Canada Business Corporations Act* through an arrangement agreement dated March 22, 2009 and accompanying plan of arrangement, as amended. Under the terms of the Arrangement, Petro-Canada shareholders received 1.28 Suncor common shares for each Petro-Canada common share held.

Our registered and head office is located at 150-6th Avenue, S.W., Calgary, Alberta, T2P 3E3.

Inter-Corporate Relationships

Material subsidiaries, each of which was owned 100%, directly or indirectly, by the company as at December 31, 2010 are as follows:

Name	Jurisdiction	Purpose
Suncor Energy Oil Sands Limited Partnership	Canada	A partnership in which Suncor Energy Inc. and certain of its wholly-owned subsidiares are partners. The partnership holds certain oil sands assets.
Suncor Energy Products Inc. (1)	Canada	An Ontario corporation that is wholly-owned by Suncor Energy Inc. through which some of Suncor's Canadian refining and marketing operations are conducted.
Suncor Energy Marketing Inc.	Canada	A subsidiary of Suncor Energy Products Inc. through which the products produced by our North American businesses are marketed. 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.
Suncor Energy (U.S.A.) Inc.	U.S.	A subsidiary of Suncor Energy Inc. through which our U.S. refining and marketing operations are conducted.
Suncor Energy Oil & Gas Partnership	Canada	A partnership in which Suncor Energy Inc. and one of its wholly-owned subsidiaries are partners. The partnership holds certain of our upstream Canadian oil and gas operations and our 12% interest in the Syncrude joint venture.
3908968 Canada Inc.	Canada	A subsidiary of Suncor Energy Inc. that holds certain of our international interests.
Petro-Canada Cooperative Holding UA	Netherlands	A subsidiary of 3908968 Canada Inc. that holds certain of our international interests.
Petro-Canada (International) Holdings BV	Netherlands	A subsidiary of Petro-Canada Cooperative Holding UA that holds certain of our international interests.
Petro-Canada Germany GmbH	Germany	A subsidiary of Petro-Canada (International) Holdings BV that holds the majority of our Libya interests.
Petro-Canada Oil (North Africa) GmbH	Germany	A subsidiary of Petro-Canada Germany GmbH through which the majority of our Libya operations are conducted.
Petro-Canada U.K. Holdings Ltd.	United Kingdom (U.K.)	A subsidiary of 3908968 Canada Inc. that holds certain of our U.K. interests.
Petro-Canada U.K. Ltd.	U.K.	A subsidiary of Petro-Canada U.K. Holdings Ltd. through which certain of our operations are conducted in the U.K.

(1) Effective January 1, 2011, Suncor Energy Products Inc. transferred substantially all of its assets and liabilities relating to Suncor's Canadian refining and marketing operations to Suncor Energy Products Partnership. Suncor Energy Products Inc. is a general partner of Suncor Energy Products Partnership.

Individually, the company's remaining subsidiaries accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2010, and (ii) less than 10% of the company's consolidated sales and operating revenues for the fiscal year ended December 31, 2010. In aggregate, the remaining subsidiaries accounted for less than 20% of each of (i) and (ii) described above.

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 in Canada and internationally, and we transport and refine crude oil, and market petroleum and petrochemical products primarily in Canada. Periodically, we also market third-party petroleum products. We also carry on energy trading activities focused principally on marketing and trading of crude oil, natural gas, refined products and byproducts, and the use of financial derivatives.

Our operating segments are composed of Oil Sands, Natural Gas, International and Offshore, and Refining and Marketing. For financial reporting purposes, we also report financial data for activities not directly attributable to an operating business under "Corporate, Energy Trading and Eliminations". This includes our energy trading activities and our investments in renewable energy opportunities.

The table below outlines various Suncor investments as at December 31, 2010:

Oil Sands
- Mining
  - *Millennium and Steepbank Mining Operations*
  - *Syncrude (12% Interest)*
  - *Fort Hills (60% Interest)(1)*
  - *Other Mining Developments*
- In Situ
  - *Firebag*
  - *MacKay River*
  - *Other In Situ Developments*
- Upgrading Facilities

Natural Gas
- Western Canada
  - *Shale (northeast British Columbia (B.C.))*
  - *Shallow (southeast Alberta)*
  - *Foothills (western Alberta, northeast B.C.)*
  - *Plains (western Alberta)*
- Northwest Territories (NWT)/Nunavut
- Alaska/Arctic Islands

Refining and Marketing
- Refineries
  - *Edmonton Refinery*
  - *Montreal Refinery*
  - *Sarnia Refinery*
  - *Commerce City (Colorado) Refinery*
  - *ParaChem Chemicals Joint Venture (51% Interest)*
- Sales and Marketing
  - *Retail Operations*
  - *Wholesale Operations*
- Mississauga Lubricants Plant

International and Offshore
- East Coast Canada
  - *Terra Nova(2) (37.675% Interest)*
  - *Hibernia (20% Interest)*
  - *Hibernia South Extension(3) (19.5% Interest)*
  - *White Rose (27.5% Interest)*
  - *White Rose Extensions(4) (26.125% Interest)*
  - *Hebron (22.7% Interest)*
- North Sea
  - *Buzzard (29.9% Interest)*
  - *Golden Eagle Area Development (26.7% Interest)*
  - *Other Exploration Acreage*
- Syria PSCs
- Libya EPSAs

Corporate, Energy Trading and Eliminations
- Energy Trading activities
- St. Clair Ethanol Plant
- Wind Farms
  - *Ripley (50% Interest)*
  - *Chin Chute (33.3% Interest)*
  - *Magrath (33.3% Interest)*
  - *SunBridge (50% Interest)*
  - *Wintering Hills (70% Interest)*
  - *Kent Breeze*

(1) On December 17, 2010, Suncor announced that it had entered into a strategic partnership with Total E&P Canada Ltd. (Total). Assuming the transaction closes, Total will acquire a portion of Suncor's interest in Fort Hills, resulting in Suncor holding a 40.8% interest. See the "Three-Year History by Segment" section for further details about this transaction.

(2) In the fourth quarter of 2010, the joint owners of the Terra Nova oilfield finalized the redetermination of working interests required under the Terra Nova Development and Operating Agreement following field payout on February 1, 2005. Suncor's working interest increased to 37.675% from 33.990%.

(3) Suncor's working interest in the Hibernia South Extension agreement is 19.5% after Nalcor Energy Oil and Gas Inc. (NALCOR) acquired its 10% unit interest effective with the signing of the related agreement on February 16, 2010.

(4) The White Rose Extensions are the White Rose North Amethyst, West White Rose and South White Rose Extensions. Suncor's working interest in the White Rose Extensions is 26.125% after NALCOR acquired its 5% working interest effective with the signing of the final project agreements in February 2009.

Three-Year History by Segment

Pursuant to a statutory plan of arrangement completed effective August 1, 2009, Suncor and Petro-Canada, and certain of their respective subsidiaries, amalgamated to form a single corporation continuing under the name "Suncor Energy Inc.". The Arrangement was effected pursuant to section 192 of the *Canada Business Corporations Act* through an arrangement agreement dated March 22, 2009 (Arrangement Agreement) and accompanying plan of arrangement, as amended (the Plan of Arrangement). Under the Arrangement Agreement and Plan of Arrangement, each holder of common shares of legacy Suncor received one common share of Suncor and each holder of common shares of legacy Petro-Canada received 1.28 common shares of Suncor for each share of Petro-Canada held. Upon completion of the Arrangement, approximately 60% of the outstanding common shares of Suncor were held by legacy Suncor shareholders and approximately 40% of the outstanding common shares of Suncor were held by legacy Petro-Canada shareholders.

Oil Sands

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 byproducts. Bitumen feedstock is also occasionally supplemented by third-party suppliers. The company also has a 12% ownership interest in the Syncrude oil sands mining and upgrading joint venture, also located near Fort McMurray, Alberta.

Key milestones and significant events that have affected our Oil Sands business during this time period include the following:

2010

- Production Overview – In the fourth quarter, our operations reached a record production of 325,900 bpd (excluding Syncrude) due to improved upgrader performance and strong bitumen supply from all of Suncor's oil sands assets. Earlier in the year, production was negatively impacted by two fires. In December 2009, there was a fire at our Upgrader 2 facility, which was repaired and returned to normal operations in February 2010. In February 2010, there was a fire at our Upgrader 1 facility, which was repaired and returned to full operations by April 2010.
- Hydrotreater Outage – Oil Sands experienced an unplanned outage at one of its hydrogen reformer units at the end of August 2010, which was repaired and returned to normal operations in October 2010. This outage impacted production mix, increasing the percentage of lower value sour crude produced, but did not impact overall production volumes.
- Reclamation of Tailings Pond – During the year, Suncor became the first oil sands company to complete surface reclamation of a tailings pond. The 220-hectare site was the company's first storage pond for oil sands tailings when commercial production began in 1967. Suncor has renamed the area Wapisiw Lookout.
- Tailings Reduction Operations (TRO_{TM}) – Suncor received regulatory approval from Alberta regulators to convert from its current Consolidated Tailings (CT) management process to TRO_{TM}, in which mature fine tails are dried, rather than mixed with sand and other materials to form CT. The processing rate for TRO_{TM} is expected to be more efficient and effective than CT. We believe that TRO_{TM} will allow Suncor to meet the requirements of the new Tailings Directive issued by Alberta's Energy Resources Conservation Board (ERCB) in 2008. Suncor plans to spend $670 million during 2011 to continue development of the TRO_{TM} initiative.
- Royalties – In the fourth quarter of 2010, Suncor received a notice from the Alberta government modifying the bitumen valuation methodology (BVM) calculation for the interim period from January 1, 2009 to December 31, 2010. As a result, Suncor recognized a pre-tax gain of $140 million for a reduction in its royalty provision. The company continues to negotiate final adjustments to the bitumen valuation calculation for the interim period and for the term of the Suncor Royalty Amending Agreement (the Suncor RAA), which expires December 31, 2015. Also, MacKay River moved to post-payout in November 2010, thereby increasing the percentage of royalties paid.
- Turnaround and Maintenance – Oil Sands completed planned turnarounds at Upgrader 1 and Upgrader 2 in 2010 and unplanned maintenance on the hydrogen reformer unit. We expect that the maintenance performed will allow for improved reliability at these plants.
- Safe Mode – In 2010, Firebag Stage 3, Firebag Stage 4 and the Millennium Naphtha Unit (MNU) projects were all taken out of safe mode. Safe mode is the deferral of projects and maintenance of equipment and facilities in a safe manner in order to expedite remobilization when appropriate.
- Powerhouse Operations – In December 2010, Suncor assumed operation of certain power and steam generation assets previously operated on our behalf by TransAlta Corporation (TransAlta). Approximately 200 employees from TransAlta joined Suncor as a result.
- Slurry at Face – Oil Sands discontinued use of certain assets involved in an alternative extraction process to crush and slurry oil sands at the mine face, resulting in a pre-tax write-off of $189 million.

2009

- Merger – On August 1, 2009, Suncor merged with Petro-Canada, resulting in the acquisition of a 12% ownership in the Syncrude joint venture (an oil sands mining operation and upgrading facility), 100% ownership of the MacKay River in situ bitumen project, a 60% ownership in, and operatorship of, the proposed Fort Hills oil sands mining project, and extensive oil sands acreage considered prospective for in situ development of bitumen resources. The merger did not result in increased Oil Sands production (excluding Syncrude) as production from MacKay River was already included in Suncor's reported production from January 1, 2009 to July 31, 2009 as volumes processed by Suncor under a processing fee arrangement.
- Steepbank Extraction Plant – This project was completed during the third quarter of 2009, resulting in improved reliability and bitumen recovery.
- Firebag Sulphur Plant – This project was also completed during the third quarter of 2009. The plant is currently operating to support sulphur emissions reductions for existing and planned in situ development at Firebag, including Stage 3.
- Safe Mode – In the first quarter of 2009, Suncor placed a number of Oil Sands projects into safe mode as a result of economic conditions at the time. As a result of placing Oil Sands projects into safe mode, Suncor incurred pre-tax costs of $380 million in 2009.

2008

- Royalties – In January 2008, we entered into the Suncor RAA with the Government of Alberta, which modified the rates under the Government of Alberta's New Royalty Framework (New Royalty Framework) that apply to our in situ operations and would otherwise apply to our base mining operations. For more information on Oil Sands royalties, please see "Industry Conditions – Royalties and Incentives – Alberta" in this AIF.
- Coker Unit – Suncor completed a $2.3 billion expansion to one of its two oil sands upgraders. This new set of cokers increased our design capacity by 90,000 bpd to a total design capacity of 350,000 bpd at our Oil Sands facilities.

The following changes to our Oil Sands business have occurred, or are expected to occur, in 2011:

- Strategic partnership with Total – In December 2010, Suncor announced that it had entered into a strategic partnership with Total E&P Canada Ltd. (previously defined as Total), setting forth the terms for the two companies to develop the Fort Hills and Joslyn oil sands mines projects jointly and restart the construction of the Voyageur Upgrader at Suncor's Oil Sands operations in Fort McMurray, Alberta. The transaction is subject to certain regulatory and other approvals, with closing targeted late in the first quarter of 2011. Key terms of the agreement between Suncor and Total include:
  - Total will acquire a 49% interest in Suncor's planned third upgrader. Upon completion, the planned 200,000 barrel per day facility will be operated by Suncor;
  - Total will also acquire a portion of Suncor's interest in the Fort Hills oil sands project, resulting in Suncor holding a 40.8% interest, Total holding 39.2%, and Teck Resources Limited (Teck) holding 20%. Currently, Suncor holds a 60% interest, with Total and Teck each holding 20%;
  - Suncor will acquire a 36.75% working interest in the Total-operated Joslyn joint venture with Total holding a 38.25%, Occidental Petroleum holding 15% and Inpex Canada Ltd. holding 10%. Currently, Total holds a 75% interest, Occidental Petroleum a 15% interest and Inpex Canada Ltd. a 10% interest; and
  - Suncor will receive cash consideration totaling approximately $1.75 billion from the transaction.

  Suncor and Total have agreed to develop the Fort Hills mine and Voyageur Upgrader in parallel, with a target of having both come on-stream in 2016. Execution of the Fort Hills and Joslyn projects, as well as the continued construction of the Voyageur Upgrader, is subject to approval by the partners in these ventures and by Suncor's Board of Directors.
- Firebag Expansion – Suncor plans to direct approximately $1.28 billion in growth spending in 2011 toward the Firebag Stages 3 and 4 in situ oil sands expansion. Suncor expects the Firebag Stage 3 project to begin production late in the second quarter of 2011, with volumes ramping up over an estimated 24-month period toward planned production capacity of approximately 62,500 bpd of bitumen.
- North Steepbank Extension (NSE) – We expect this extension will improve the productivity of mining equipment by opening up a new mine face. Suncor expects to develop the mine face in 2011 and commence mining ore from the NSE in 2012.

- By the end of 2011, Suncor expects to complete the construction of the MNU to complement its upgrading assets. This new unit is expected to add 30,000 bpd of naphtha hydrotreating capacity to further upgrade sour SCO into sweet SCO.
- Suncor expects to complete a six-week turnaround of one of its upgraders, resulting in a decrease in production of approximately 215,000 bpd during that period.

Natural Gas

Our Natural Gas business explores for, acquires, develops and produces natural gas, NGLs, oil and byproducts from reserves in Western Canada. This business also has assets in NWT, Alaska, and the Arctic Islands.

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

2010

- Canadian Dispositions – Throughout the year, the company completed several sales of non-core natural gas properties in Canada, including:
  - On September 30, 2010, the company completed the sale of its properties located in southern Alberta, known as Wildcat Hills, for net proceeds of $351 million.
  - On August 31, 2010, the company completed the sale of its properties located in west central Alberta, known as Bearberry and Ricinius, for net proceeds of $275 million.
  - On May 31, 2010, the company completed the sale of properties located in central Alberta, known as Rosevear and Pine Creek, for net proceeds of $229 million.
  - On March 31, 2010, the company completed the sale of certain properties located in northeast B.C. known as Blueberry and Jedney, for net proceeds of $383 million.
- U.S. Dispositions – On March 1, 2010, the company completed the sale of substantially all of its U.S. Rockies upstream assets for net proceeds of US$481 million. Remaining U.S. Rockies upstream assets were sold shortly thereafter.
- Shallow Gas – Suncor's key shallow gas producing properties near Medicine Hat, in southeast Alberta, continued with drilling and tie-in activity. In total, 324 wells were drilled in 2010.
- Other Drilling Programs – In the fourth quarter of 2010, we began two new drilling programs: one in the Ferrier area located in central Alberta and another at Pouce Coupe in western Alberta. Both programs are expected to start being tied-in during the first quarter of 2011.

2009

- Merger – On August 1, 2009, Suncor merged with Petro-Canada, adding significant natural gas assets in Western Canada and the U.S. Rockies, as well as assets in Alaska, the NWT and the Arctic Islands.

The following changes to our Natural Gas business have occurred, or are expected to occur, in 2011:

- Organizational Change – In January 2011, Suncor announced organizational changes that included the International and Offshore and Natural Gas business divisions merging into a single conventional production-focused organization, including both onshore and offshore operations.
- Additional Planned Divestitures – As part of its strategic business alignment, Suncor is targeting further divestments of non-core natural gas assets of approximately 220 MMcfe/d.

International and Offshore

International and Offshore consists of conventional oil and gas exploration, development and production offshore Newfoundland and Labrador, in the North Sea, and in Libya and Syria. Suncor acquired the International and Offshore assets in the merger with Petro-Canada in 2009.

Our East Coast Canada business comprises production and exploration activity offshore Newfoundland and Labrador. The company has a position in every major producing oil development in the region and is the operator of the Terra Nova oilfield. The company also holds a number of exploration licences and significant discovery licences in the region.

Our International business focuses on countries and regions where material positions of long-life assets may be built. This includes the exploration for, and production of, crude oil and natural gas primarily in the North Sea (offshore U.K. and Norway), Libya and Syria.

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

East Coast Canada

2010

- Terra Nova Redetermination – On December 1, 2010, the joint owners of the Terra Nova oilfield finalized the redetermination of working interests required under the Terra Nova Development and Operating Agreement following field payout on February 1, 2005. Suncor's working interest increased to 37.675% from 33.990%, and the other owners have agreed to reimburse the company for its increased working interest from February 1, 2005 to December 31, 2010. As a result, the company recognized a pre-tax gain of $295 million.
- Terra Nova Production – In the fourth quarter of 2010, during regular well testing, we encountered hydrogen sulphide (H_2S) in part of the Terra Nova oilfield. We have safely shut-in affected wells and facilities while we develop a mitigation plan.
- Hibernia South – Final fiscal agreements were made between co-venturers and the Government of Newfoundland and Labrador in February 2010 for the Hibernia South Extension. The development plan for the extension has been approved and sanction is expected in the first quarter of 2011. First oil from platform development wells is expected in the first half of 2011.
- White Rose Extensions – On May 31, 2010, first oil was achieved at the North Amethyst portion of the White Rose Extensions, and development drilling continues.

2009

- Hibernia Production – Production from the AA Block began in the fourth quarter of 2009.

North Sea

2010

- U.K. Dispositions – On September 8, 2010, the company reached agreements to sell non-core U.K. offshore assets (Scott/Telford and Triton) for gross proceeds of £240 million, effective July 1, 2010. Divestment of a portion of these assets was completed in 2010 for net proceeds of £55 million. The sales of the remaining assets are expected to close during the first half of 2011. The remaining divestments are subject to closing conditions, closing adjustments to the purchase price and regulatory and other approvals customary for transactions of this nature.
- Netherlands Disposition – On August 13, 2010, the company completed the sale of its shares in Petro-Canada Netherlands BV for net proceeds of €316 million, with an effective date of January 1, 2010.
- Buzzard Production – In October 2010, a shutdown and tie-in of the fourth platform at Buzzard was completed and staged commissioning began on the sulphur handling platform. Production disruptions during ramp-up have been minimal to date. Commissioning of the new platform will continue in the first quarter of 2011.
- Norway Exploration – The company completed its first operated exploration well in January 2010 and encountered hydrocarbons. An appraisal well was drilled and tested in the fourth quarter of 2010 with positive results. Further evaluation is required to determine the potential size of this discovery. Suncor submitted bids for further acreage in Norway in the fourth quarter of 2010.

2009

- Buzzard Production – Production was shut-in for four weeks for the installation of the jacket for the fourth platform at Buzzard, which will handle sulphur.
- U.K. Exploration – There was a non-operated oil discovery called Hobby. This discovery will allow the Golden Eagle area to move forward to a pre-development stage.

2008

- U.K. Exploration – There was a non-operated oil discovery called Pink. The Pink Block is located in the Golden Eagle Area Development.

Libya

2010

- Exploration – Suncor progressed with its seismic acquisition program, with completion planned for March 2011. Starting in April, Suncor drilled two exploration wells and four appraisal wells.
- Development Drilling – Suncor completed 26 development wells in the producing fields in Libya, with an additional four development wells drilling at year end. Suncor completed eight development wells in 2009 and twelve development wells in 2008.
- Signature Bonus Payments – Suncor made a payment of US$200 million to the Libya National Oil Corporation (NOC) related to its EPSAs. Additionally, in return for the NOC providing consent in writing to the merger of Suncor and Petro-Canada, and to Suncor being accepted as the guarantor to the NOC of our legal entities in Libya as set out in the EPSAs, Suncor agreed to make a payment of US$94 million.

2008

- Libya EPSAs – In June 2008, six new EPSAs with the NOC were signed to replace existing concession agreements and one EPSA. The agreements will expire in 2033.

Syria

2010

- Operations – Suncor achieved commercial production from the Ebla natural gas project on April 19, 2010. First oil was achieved from Ebla on December 10, 2010. The company also submitted bids for additional acreage in Syria in December 2010.

Trinidad and Tobago

2010

- Disposition – On August 5, 2010, the company completed the sale of its Trinidad and Tobago assets for net proceeds of US$378 million with an effective date of January 1, 2010.

The following changes to our International and Offshore business have occurred, or are expected to occur, in 2011:

- Libya – In late February, civil unrest swept Libya, where Suncor has both oil production and exploration activities. At the time of filing this report, the degree and duration of impact on our business is not known. Suncor's immediate focus has been the safety of expatriate and Libyan national staff, and the contractors and service providers supporting Suncor's operations.
- Organizational Change – In January 2011, Suncor announced organizational changes that included the International and Offshore and Natural Gas business divisions merging into a single conventional production-focused organization, including both onshore and offshore operations.
- White Rose Extension – First oil for the West White Rose Phase 1 extension is expected in the second quarter of 2011. Results of Stage 1, combined with ongoing evaluation, will help define the scope of Stage 2.
- Hebron – The development plan approval submission is expected to be made in the second quarter of 2011, with first oil expected in 2017.
- In January 2011, Suncor was awarded two new production licences in Norway.

Refining and Marketing

Our Refining and Marketing business refines crude oil at Suncor's refineries in Edmonton, Alberta, Montreal, Quebec and Sarnia, Ontario in Canada, and in Commerce City, Colorado, U.S., into a broad range of petroleum and petrochemical products for sale to retail, commercial and industrial customers. In 2010, our Refining and Marketing business averaged sales of 87,800 cubic metres per day (m^3/d) of refined products nationwide in Canada and in Colorado, as well as into other parts of the

United States and Europe. Refining and Marketing transports crude oil through pipelines in Eastern and Western Canada, and through wholly-owned pipelines in Wyoming and Colorado.

Our Refining and Marketing business also includes a lubricants plant in Mississauga, Ontario that produces specialty lubricants and waxes.

In Canada, our retail business is managed primarily through Petro-Canada$_{TM}$-branded retail sites. In Colorado, our retail business is primarily managed through Phillips 66® and Shell®-branded sites.

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

2010

- Retail Site Rebranding – Suncor rebranded 158 Sunoco$_{TM}$ retail sites to substantially complete the consolidation of our post-merger Canadian offering under the Petro-Canada$_{TM}$ brand.
- Retail Site Disposition – Suncor divested 104 retail sites in Ontario to comply with Canadian Competition Bureau requirements relating to the merger with Petro-Canada.
- Edmonton Refining Capacity – Following improvements completed in previous years, the observed performance of the Edmonton refinery enabled us to upwardly revise our crude oil capacity to 135,000 bpd from the previously disclosed 125,000 bpd, effective January 1, 2010.
- Oil Sands Diesel Marketing – Responsibility for marketing diesel production from Suncor's Oil Sands upgraders was transferred to Refining and Marketing from Suncor's Energy Trading division in mid-2010.
- St. Clair Ethanol Plant – Responsibility for operation and ownership of the St. Clair Ethanol Plant in Ontario was transferred from Refining and Marketing to Suncor's Renewable Energy division in early 2010.

2009

- Merger – On August 1, 2009, Suncor merged with Petro-Canada and acquired the Edmonton and Montreal refineries (with a total daily crude oil capacity of 255,000 bpd), a lubricants plant that is the largest producer of lubricant base stocks in Canada, a network of retail service stations, a national commercial road transport system and a bulk fuel sales channel.
- Terminal Storage and Distribution Capacity – In conjunction with Canadian Competition Bureau requirements relating to the merger, Suncor entered into terminalling agreements for 10 years with Ultramar Ltd. to provide 1.1 billion litres of terminal and distribution capacity in the Greater Toronto Area.
- Commerce City Refinery Capacity – The Commerce City refinery revised its crude oil capacity to 93,000 bpd from 90,000 bpd on January 1, 2009 to more accurately reflect the combined capability of its multiple crude processing trains.

2008

- Edmonton Refinery Conversion – The Edmonton refinery completed its refinery conversion project to process 100% oil sands-based feedstock.
- Sarnia Refining Capacity – The Sarnia refinery revised its crude oil capacity to 85,000 bpd from 70,000 bpd, based on observed performance after the completion of the diesel desulphurization and oil sands integration projects in 2007.

The following changes to our Refining and Marketing business have occurred, or are expected to occur, in 2011:

- The Sun Petrochemicals Company joint venture partnership agreement between Suncor and a Toledo, Ohio-based refinery was terminated on December 31, 2010. Starting in 2011, petrochemical sales out of our Sarnia refinery will be marketed solely by Suncor's Refining and Marketing division.

Other Suncor Businesses

Renewable Energy

Key milestones and significant events that have affected our renewable energy interests during the past three years include the following:

2010

- Wintering Hills – After receiving approval from the Alberta Utilities Commission, the company began construction on an 88 megawatt (MW), 55 turbine wind power project, located in southern Alberta. The company has signed a joint venture agreement with Teck Resources Limited (Teck) to develop the project. Under the terms of the agreement, Suncor will own a 70% interest and operate the project and Teck will own the remaining 30%. The project is expected to be completed by the end of 2011.
- Kent Breeze – Suncor also received regulatory approval for and began construction on a 20 MW, eight turbine wind power project located in southwest Ontario. The project is expected to be completed by the second quarter of 2011.

The following changes to our Renewable Energy business have occurred, or are expected to occur, in 2011:

- St. Clair Ethanol Expansion Project – Suncor completed a $120 million expansion of its ethanol plant in Ontario on January 22, 2011. The project expanded existing plant capacity from 200 million litres per year to 400 million litres per year.

Forward-Looking Information

The preceding paragraphs describing the general development of our business contain forward-looking statements, including those related to: cost estimates; the Total transaction (and the anticipated terms of same); our TRO_{TM} process, and the expectation that we will spend $670 million during 2011 to continue development of the initiative; the planned expansion of Firebag Stages 3 and 4, NSE and MNU assets (and expected production and capacity relating to the foregoing assets); expected turnarounds; planned divestitures of our natural gas assets and U.K. assets; anticipated first oil from some of Suncor's International and Offshore assets; and project completion dates. The material factors and assumptions used to develop the foregoing forward-looking statements include those related to the following: current capital spending plans; the current status of procurement, design and engineering phases of projects; updates from third-parties on delivery of services and goods associated with the projects; and estimates from major project teams on completion of future phases of the project. We have assumed that commitments from third parties will be honoured and that material delays and increased costs related to projects will not be encountered. Assumptions for production outlook include implementing reliability and operational efficiency initiatives, which we expect to minimize further unplanned maintenance. We have also provided forward-looking statements concerning the timing of the proposed transaction with Total and the development of the Fort Hills mine and Voyageur upgrader. Suncor has provided these anticipated times in reliance on certain assumptions that Suncor believes are reasonable at this time, including assumptions as to the timing of receipt of the necessary regulatory, court and other third party approvals; and the time necessary to satisfy the conditions to the closing of the transaction. These dates may change for a number of reasons, including unforeseen delays in the inability to secure necessary regulatory or other third-party approvals in the time assumed or the need for additional time to satisfy the conditions to the completion of the transaction. There is no assurance that the transaction will close as scheduled or at all, or if it does close, that any of the key terms of the agreement will come to fruition. For additional information on risks, uncertainties and other factors that could cause actual results to differ, please see the "Forward-Looking Statements" section above and the our Risk Factors section of this AIF.

NARRATIVE DESCRIPTION OF SUNCOR'S BUSINESSES

Oil Sands

Operations

Our integrated Oil Sands business involves five operations located near Fort McMurray, Alberta:

- Oil sands ore is supplied from open pit mining operations.

  Open pit mining operations extract the overburden with trucks and shovels to provide access to the oil sands, which are excavated and delivered via hydrotransport pipeline to ore preparation plants, where crushers and sizers prepare the ore for primary extraction.

- Primary extraction facilities recover the bitumen from the mined oil sands ore.

  In the primary extraction process, raw bitumen is separated from sand using a hot water process in giant separation cells. After the final removal of impurities and minerals during secondary extraction, naphtha is added to dilute the bitumen to facilitate transportation to upgrading facilities.

- In situ operations provide additional bitumen to upgrading facilities.

  Our in situ operations, Firebag and MacKay River, use 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 and water mixture 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. At our Firebag operation, naphtha is added to dilute the bitumen to facilitate transportation to our upgraders. At our MacKay River operation, a heated pipeline is used instead of naphtha dilution for transport. The bitumen is transported to our upgrading facilities or sold directly to market.

- Upgrading facilities convert bitumen into crude oil products.

  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 SCO, is either sold directly to customers or upgraded further into sweet SCO by removing the sulphur and nitrogen using a hydrogen treating process. In addition to sweet and sour SCO, our upgrading also produces diesel, naphtha, kerosene and gas oil.

- 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. Process water is used in extraction processes. Steam generation is critical to SAGD processes and also assists in the production of energy in Suncor's plants. Excess energy produced is sold back to the power grid.

There are virtually no finding costs associated with oil sands resources; however, the delineation and development (mining and in situ drilling) of the resources, and the upgrading of bitumen into SCO involve significant capital outlays. As a result, our production costs are largely fixed in the short term such that operating costs per unit are largely dependent on levels of production. Natural gas is used in the production of SCO, particularly in our SAGD operations, and, accordingly, natural gas prices are a key variable component of SCO production costs.

We continue to explore and develop improved and alternative technologies to facilitate increased efficiency within our operations. In the normal course of our operations, we regularly conduct planned maintenance shutdowns of our facilities. These shutdowns provide opportunities for both preventive maintenance and capital replacement, which are expected to improve operational efficiency.

Suncor also holds a 12% interest in Syncrude, which operates the North and Aurora oil sands mines, a utilities plant, bitumen extraction plant and upgrading facility that processes bitumen and produces SCO. Mine operations use truck, shovel and hydrotransport systems. Suncor's share of SCO production is processed primarily at our refinery in Edmonton, Alberta, with the balance periodically processed in Eastern Canada and in the United States.

In 2010, production at Suncor's Oil Sands facilities averaged 283,000 bpd, and Suncor's share of production from Syncrude averaged 35,200 bpd.

Transportation

Suncor owns a pipeline that transports SCO from our facilities in Fort McMurray, Alberta to Edmonton, Alberta. The pipeline has a capacity of approximately 110,000 bpd and is operated by Suncor's Refining and Marketing business.

We have a transportation service agreement on the Enbridge Athabasca Pipeline for a term that commenced in 1999 and extends to 2028. Total line design capacity is 600,000 bpd, and the current configuration capacity is 350,000 bpd. Under this agreement, our current pipeline commitment is 182,000 bpd for the transportation of SCO and diluted bitumen from Fort McMurray, Alberta to Hardisty, Alberta.

We are a founding member of the Waupisoo Pipeline, owned and operated by Enbridge Inc. (Enbridge) that went into service on June 1, 2008. Under the 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. Our pipeline commitment under this agreement is 75,000 bpd for the transportation of SCO and diluted bitumen from Cheecham, Alberta to Edmonton, Alberta.

Following the Petro-Canada merger, we additionally assumed i) a short-haul commitment from Fort McMurray to Cheecham for 58,000 bpd on the Enbridge Athabasca Pipeline; ii) a lateral transportation agreement for 40,000 bpd from MacKay River to the Athabasca Tank Terminal that also includes contracted storage facilities of 250,000 bbls, which expires June 30, 2017; and iii) contracted storage facilities at Edmonton for 500,000 bbls, which expires March 31, 2028.

In 2009, Suncor 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. Our capacity from Hardisty, Alberta to Patoka, Illinois is 25,000 bpd. In 2011, our contracted capacity from Patoka, Illinois to Cushing, Oklahoma is 50,000 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 MMbbls of storage and for fixed five-year terms. On January 1, 2009, Suncor contracted storage facilities for an additional 1.2 MMbbls at Nederland, Texas for a fixed five-year term. Until the company completes its Oil Sands growth projects, Suncor's Energy Trading business expects to optimize the capacities associated with these arrangements.

In 2008, we entered into 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 starting in 2009). The Express New Pipeline runs from Hardisty, Alberta to Wood River, Illinois, and helps enable delivery of sour SCO production to our Commerce City refinery or to the Gulf Coast. The Wamsutter Pipeline in Wyoming runs from Wamsutter to Fort Laramie and also primarily helps deliver crude oil feedstock to the Commerce City refinery. We continue to evaluate additional pipeline agreements to support planned increases in production capacity.

Periodically, we also enter into strategic short-term cargo transportation agreements to ship SCO 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. This pipeline extends approximately 300 kilometres south of the Oil Sands plant and is connected to TransCanada PipeLine Limited's (TCPL) Alberta intra-provincial pipeline system. The Albersun Pipeline had the capacity to move in excess of 100 MMcf/d of natural gas in both north and south directions until we closed our Atmore receipt terminal in November 2009. Following this closure, our capacity became 46 MMcf/d in the north direction only. We arrange for natural gas supply and purchase most of the natural gas on the system under delivery-based contracts.

Our Oil Sands mining facilities are readily accessible by public road. Our Firebag in situ facilities are currently accessible by air and private road, while our MacKay River in situ facilities are accessible by a combination of public and private roads. We anticipate termination of the current road access to Firebag in 2011. The East Athabasca Highway was completed in the fourth quarter of 2010 to provide access to the Firebag site. This highway is owned by Suncor, Husky Energy Inc. and Imperial Oil Ltd. to provide each company with access to its oil sands operations in the area.

Principal Products

Sales of light sweet SCO and diesel represented 45% (2009 – 48%) and sales of light sour SCO and bitumen represented 49% (2009 – 49%) of Oil Sands consolidated operating revenues in 2010. Information on daily sales volumes and the corresponding percentage of Oil Sands operating revenues by product for each of the last two years are as follows:

Product:	2010		2009	
	Mbbls/d	% of operating revenues	Mbbls/d	% of operating revenues
Sweet synthetic crude oil[1] / diesel	137.9	45	144.9	48
Sour synthetic crude oil / bitumen	176.6	49	147.5	49
Total	314.5		292.4	

(1) Includes sales of Syncrude production, effective August 1, 2009.

Sales of Synthetic Crude Oil, Bitumen and Diesel

SCO and bitumen production from our Oil Sands operations is sold to and subsequently marketed by Suncor's Energy Trading business. Primary markets for our synthetic crude oil and bitumen products include refining operations in Alberta, Ontario, the U.S. Midwest and the U.S. Rocky Mountain regions. Diesel products are sold primarily in Western Canada, marketed by Suncor's Refining and Marketing business.

For production of bitumen from our in situ assets, Oil Sands operating strategy allows Suncor to take advantage of changes in market and operating conditions by either: a) upgrading the bitumen directly at our Oil Sands facilities; b) upgrading the bitumen at Suncor's refineries, by transporting diluted bitumen to those facilities; or c) selling diluted bitumen directly to third parties.

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 of sour crude from our Oil Sands operations. We began shipping the crude to Flint Hills at Hardisty, Alberta on January 1, 1999. The term of the initial agreement expires on June 30, 2011. A new agreement was negotiated to supply Flint Hills with 20,000 bpd beginning July 1, 2011. The initial term of that agreement extends to June 30, 2014 and will continue thereafter until termination upon a minimum of 24 months notice by either party.

Under a long-term sales agreement from August 2001 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. The initial term of both CCRL agreements is 15 years with five-year evergreen terms thereafter subject to termination by either party on 24 months notice. Neither party has provided notice of termination at this time.

A portion of our Oil Sands production is used in our refining operations. Our refineries processed the following portion of our total Oil Sands crude sales in the past two years:

Refinery	Year Ended December 31, 2010		Year Ended December 31, 2009	
	Mbbls/d	% total Oil Sands sales (1)	Mbbls/d	% total Oil Sands sales (1)
Edmonton (2)	55	24	58	25
Sarnia	60	27	44	18
Commerce City	9	4	9	4
Total	124		111	

(1) Calculated based on Oil Sands sales, excluding diesel and bitumen sales.

(2) For 2009, reflects operations subsequent to the Petro-Canada merger on August 1, 2009.

There were no customers that represented 10% or more of our consolidated revenues in 2010 or 2009.

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.

Environmental Compliance

For a discussion of environmental risks at our Oil Sands operations, refer to "Government Regulation" in the Risk Factors section of this AIF.

As part of Suncor's strong focus on operational excellence, Suncor has set four key environmental performance goals it intends to reach by 2015 (the base year for planned improvements is 2007): reduce total water intake by 12%, increase land area reclaimed by 100%, improve energy efficiency by 10% and reduce air emissions by 10%. In addition, Suncor has advanced strategies focused on operational excellence aimed at further improving process safety and reliability, which in turn will impact our environmental impact. Suncor has adopted a clear set of process safety management standards and has implemented the same at all of our facilities.

In 2010, Suncor reclaimed the industry's first tailings pond to a trafficable surface. As well, Suncor received approval and started implementation of a new tailings technology, TRO_{TM}, which Suncor expects will significantly reduce tailings reclamation time. The technology has already enabled Suncor to cancel plans to build five additional tailings ponds at its existing operations. Suncor will continue to pursue the implementation of TRO_{TM} across its existing operations and continue to take a leadership position in collaborative efforts with industry counterparts on the development of environmental technologies. Suncor expects to spend significant amounts of capital over 2010 and 2011 to implement TRO_{TM}. This represents a significant step forward in addressing one of the biggest environmental challenges facing the oil sands industry.

Suncor will also work closely with the Oil Sands Leadership Initiative (OSLI). Comprised of Suncor, Total and three other like-minded oil sands companies, this organization is squarely focused on innovations that lead to continuous improvement in environmental, social and economic performance.

Suncor has implemented a regulatory compliance assurance process applicable to its ongoing operations and proposed future projects. A major component of the regulatory assurance work is carried out through the implementation of a software system that sets out applicable legal requirements and generates tasks to meet these requirements. To date, the scope of the regulatory compliance assurance process has included environmental regulatory compliance, mainly associated with Suncor's Oil Sands and In Situ operations

Suncor has also implemented a comprehensive roles and responsibilities matrix as part of our greenhouse gas (GHG) management program. For details refer to "Suncor's Governance Process" in the Risk Factors section of this AIF.

Natural Gas

Our Natural Gas business explores for, develops and produces natural gas, NGLs, crude oil and byproducts in Western Canada, supplying markets throughout North America. After the merger with Petro-Canada, we implemented a new strategy with greater emphasis on unconventional gas. To focus on this goal, and to help reduce the company's debt, we decided to sell a number of non-core natural gas assets.

Our exploration program is primarily focused on multiple geological zones throughout Western Canada. The business is structured with the following core asset areas:

- Shale (northeast B.C.);
- Shallow (southeast Alberta);
- Foothills (western Alberta and portions of northeast B.C.); and
- Plains (western Alberta).

Marketing, Pipeline and Other Operations

In Western Canada, Suncor operates 10 natural gas processing plants, with total licensed capacity of 793 MMcf/d, of which the company's share is 481 MMcf/d. The following table shows Suncor's working interest ownership and the licensed capacity of operated processing plants as at December 31, 2010.

Suncor Operated Plants	Working Interest Ownership %	Gross Licensed Capacity MMcf/d	Net Licensed Capacity MMcf/d
Hanlan Sweet	40.73	44.2	18.0
Hanlan Sour	49.86	382.0	190.5
Wilson Creek	52.17	34.6	18.1
Boundary Lake Sweet	100.00	20.0	20.0
Boundary Lake Sour	50.00	66.0	33.0
Parkland 1	43.98	18.1	8.0
Parkland 2	34.75	11.7	4.1
Ferrier	99.99	120.0	120.0
Gilby East	100.00	52.4	52.4
Progress	38.46	44.0	16.9
Total		**793.0**	**481.0**

Suncor also has varying working interests in other natural gas processing plants and field gathering facilities operated by other oil and natural gas companies. The company's aggregate share from such interests is 91.5 MMcf/d of licensed capacity.

In 2010, Suncor's share of production from its Natural Gas properties was 575 MMcfe/d, with 432 MMcfe/d produced from continuing operations.

Substantially all of our natural gas production is sold to our Energy Trading business, which then markets the product to our customers under direct sales arrangements. Contracts for these direct sales arrangements are of varied terms, with a majority having terms of one year or less, and incorporate pricing that 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.

To provide price diversity for natural gas marketing Suncor holds 85,000 MMcf/d of firm capacity on the Alliance Pipeline system and 68,000 MMbtu per day on the TCPL Gas Transmission Northwest Pipeline (GTN). The Alliance pipeline capacity, which expires in December 2015, enables Suncor to transport high-energy, rich natural gas from northeast B.C. and northwest Alberta to the Alliance pipeline terminus in Illinois. The GTN capacity, which expires in 2023, enables Suncor to deliver natural gas to the Pacific Northwest and California markets.

Suncor does not typically enter into long-term supply arrangements to sell its conventional crude oil and NGL production. Instead, our conventional crude oil and NGL 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 77% of the Natural Gas business segment's consolidated operating revenues in 2010, with 22% comprised of sales of NGLs and crude oil. The remaining 1% is related mainly to sales of sulphur byproduct. Average daily sales volumes and the corresponding percentage of Natural Gas's operating revenues by product for the last two years are as follows:

Product:	2010		2009	
	MMcfe/d	% of operating revenues	MMcfe/d	% of operating revenues
Natural gas	522	77	397	76
Crude oil and NGLs	53	22	49	23
Total	575		446	

Competitive Conditions

For a discussion of the competitive conditions affecting the Natural Gas business, 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 "Government Regulation" in the Risk Factors section of this AIF.

International and Offshore

The International and Offshore business explores for, develops and produces crude oil and natural gas offshore Newfoundland and Labrador and in the North Sea, primarily in the U.K. and Norway, and conventionally in Libya and Syria. International and Offshore's business interests include:

East Coast Canada

- Suncor is the operator of Terra Nova oilfield, holding a 37.675% interest.
- A 20% interest in the Hibernia oilfield (including the AA Blocks) and a 19.5% interest in the Hibernia South Extension.
- A 27.5% interest in the White Rose oilfield and a 26.125% interest in the North Amethyst, West White Rose and South White Rose Extensions (collectively the White Rose Extensions).
- A 22.7% interest in the Hebron oilfield.
- Interests in 47 significant other discovery licences and seven other exploration licences offshore Newfoundland and Labrador.

North Sea

- A 29.9% interest in the Buzzard oilfield.
- A 26.69% interest in the Golden Eagle Area Development.

Libya

- Six EPSAs to extend development of energy resources in Libya's oil fields. The EPSAs provide exploration opportunities in the Sirte Basin.

Syria

- Two PSCs in Syria to develop and produce natural gas and other hydrocarbons from Syrian fields. One PSC relates to the Ebla gas project and the other relates to another onshore exploration block.

As part of its strategic business alignment, during 2010, Suncor divested all of its Trinidad and Tobago assets and certain non-core North Sea assets, including all assets in The Netherlands.

Exploration and Production

East Coast Canada

Terra Nova

The Terra Nova oilfield, which is approximately 350 kilometres southeast of St. John's, Newfoundland, was discovered by Petro-Canada in 1984. Terra Nova is the second oilfield to be developed offshore Newfoundland and Labrador. This Suncor-operated production system uses a Floating Production, Storage and Offloading (FPSO) vessel that is moored on location, with a gross production capacity of 180,000 bpd and storage capacity of 960,000 bbls. Terra Nova was the first harsh environment development in North America to use a FPSO vessel. Actual production levels are lower than production capacity, reflecting current reservoir capability. Production from the Terra Nova oilfield began in January 2002. The field is estimated to have a remaining production life of approximately 13 to 20 years at current rates.

On December 1, 2010, the joint owners of the Terra Nova oilfield finalized the redetermination of working interests required under the Terra Nova Development and Operating Agreement following field payout on February 1, 2005. As a result, Suncor's working interest increased to 37.675% from 33.990% effective January 1, 2011.

At December 31, 2010, there were 15 producing oil wells, nine water injection wells and three gas injection wells in operation. Field production is transported by shuttle tanker from the FPSO to either a transshipment terminal on Placentia Bay or, if tanker schedules permit, directly to market. Crude oil delivered to the transshipment facility is transferred to storage tanks and loaded onto tankers for transport to markets in Eastern Canada and the U.S. Suncor has a 14% ownership interest in the transshipment facility.

In 2010, Suncor's share of Terra Nova production averaged 23,200 bpd. H_2S was detected in several production wells in the fourth quarter of 2010. The affected wells and facilities have been safely shut-in while the company develops a mitigation plan to safely address the situation.

Hibernia and Hibernia South

The Hibernia oilfield, encompassing the Hibernia and Ben Nevis Avalon reservoirs, is approximately 315 kilometres southeast of St. John's and was the first field to be developed in the Jeanne d'Arc Basin. Operated by Hibernia Management and Development Company Ltd., the production system is a fixed Gravity Base Structure (GBS), which sits on the ocean floor. The GBS has gross production capacity of 230,000 bpd and storage capacity of 1.3 MMbbls. Actual production levels are lower reflecting current reservoir capability and natural decline. Hibernia commenced production in November 1997. The Hibernia oilfield is estimated to have a remaining production life of 25 to 30 years at current rates.

Final fiscal agreements were signed between co-venturers and the Government of Newfoundland and Labrador in February 2010 that established the key fiscal, equity and operational principles for the development of the Hibernia South Extension. The Hibernia South Unit Development Plan Amendment (DPA) was approved by the Canada Newfoundland and Labrador Offshore Petroleum Board (CNLOPB) on September 3, 2010. The federal and provincial governments approved the CNLOPB decision on October 8, 2010. Subject to completion of certain agreements with the federal government, production from Hibernia South is expected in mid-2011, with the completion of the first oil producer/water injector well pair.

At December 31, 2010, there were 34 producing oil wells, 24 water injection wells and six gas injection wells in operation. Hibernia uses the same transshipment terminal and the same system of shuttle tankers that are used for Terra Nova, and also transports its crude oil to markets in Eastern Canada and the U.S.

In 2010, Suncor's share of Hibernia production averaged 30,900 bpd.

White Rose and the White Rose Extensions

White Rose, the third oilfield development offshore Newfoundland, is about 350 kilometres southeast of St. John's. Operated by Husky Oil Operations Limited, White Rose uses a FPSO vessel (similar to Terra Nova) that has a gross production capacity of

140,000 bpd and a storage capacity of 940,000 bbls. Production from the White Rose oilfield began in November 2005. The field is estimated to have a remaining production life of approximately 15 to 18 years at current rates.

In December 2007, the White Rose joint venture participants signed a formal agreement with the Province of Newfoundland and Labrador for the development of the White Rose Extensions, incorporating the South White Rose Extension, North Amethyst and West White Rose satellite fields. In May 2010, first oil was achieved in the North Amethyst portion of the White Rose Extensions and development drilling is ongoing. Development of the West White Rose Extension will be divided into two stages. Stage 1 was approved in the second quarter of 2009. First oil from the West White Rose Extension is expected by mid-2011 following completion of the first production well. Results of Stage 1, combined with other ongoing evaluation, will help define the scope of Stage 2.

At December 31, 2010, there were 10 producing oil wells and 12 water injection wells in operation. White Rose uses the same transshipment terminal and the same system of shuttle tankers that are used for Hibernia and Terra Nova, and also transports its crude oil directly to markets in Eastern Canada and the U.S.

In 2010, Suncor's share of White Rose production averaged 14,500 bpd.

Hebron

Hebron is an oilfield discovery located 340 kilometres southeast of St. John's. In August 2008, the Hebron joint venture participants reached an agreement with the Government of Newfoundland and Labrador on commercial terms that will allow development activities to proceed for Hebron. The project will be operated by ExxonMobil Canada Ltd. The contract for front end engineering and design for topsides, procurement and construction was awarded in September 2010. The development plan application is expected to be submitted for approval in the second quarter of 2011, with first oil expected in 2017.

Other Exploration Offshore Newfoundland

In addition to existing East Coast Canada developments, Suncor also holds interests in a number of other discoveries and continues to pursue opportunities offshore Newfoundland and Labrador.

North Sea

The Buzzard oilfield is located in the Outer Moray Firth, 95 kilometres northeast of Aberdeen, Scotland. Operated by Nexen Petroleum U.K. Limited, the Buzzard system has production capacity of 200,000 bpd of oil and 60 mmcf/d of natural gas. Buzzard achieved first oil in January 2007 and reached peak production in the middle of 2007. Buzzard is supported by four bridge-linked platforms supporting wellhead facilities, production facilities, sulphur handling, and living quarters and utilities. Crude oil is transported via the Forties pipeline system to the Kinneil terminal in Scotland, and natural gas is transported via the Frigg pipeline to the St. Fergus gas terminal in Scotland. Commissioning of the fourth platform, installed to remove H_2S in the oil production from some segments of the field, was initiated in 2010 and will continue into the first quarter of 2011. The field is expected to have a remaining production life of approximately 20 years at current rates.

An agreement has been reached to unitize the discoveries in Pink, Hobby and Golden Eagle into a pre-development project called the Golden Eagle Area Development. A development project is ongoing with first oil projected in 2014-2015.

In 2010, Suncor reached agreements to sell non-core offshore U.K. assets (Scott/Telford and Triton) and completed the sale of a portion of these assets. Suncor also sold its non-core offshore Netherlands assets.

In 2010, Suncor's share of North Sea production averaged 79,000 boe/d, including 55,500 boe/d from Buzzard.

In Norway, the company completed its first operated exploration well in January 2010 and encountered hydrocarbons. An appraisal well was drilled and tested in the fourth quarter of 2010 with positive results. Further evaluation is required to determine the potential size of this discovery.

Libya

Suncor conducts its Libya operations pursuant to EPSAs, under which the company pays 50% of the costs and recovers these costs from 12% of production. Excess production is then shared between Suncor and the Libyan government. The EPSAs, which expire in 2033, enable Suncor and the NOC to design and implement jointly the redevelopment of the existing fields in the Sirte Basin.

As a result of the merger, the company assumed the remaining US$500 million obligation for a signature bonus relating to Petro-Canada's ratification of the EPSAs in 2008. As at December 31, 2010, the undiscounted value of Suncor's remaining obligation is US$290 million, payable in several installments through 2013. Under the EPSAs, Suncor is the exploration operator and has committed to fully fund an exploration program, at an estimated remaining cost of US$335 million. Failure by Suncor to conduct its exploration commitment or make the signature bonus payments could result in the NOC terminating the EPSAs, which would result in Suncor losing all of its rights to production in Libya.

In 2010, Suncor's share of production in Libya averaged 35,200 boe/d.

Syria

The Ebla gas project is operated pursuant to a PSC, under which the company pays 100% of the costs and recovers these costs from a 40% share of production after deduction for royalties of 12.5%. The remaining profit is shared between Suncor and the Syria government. The Ebla PSC will expire in April 2035.

First commercial gas production from Ebla was achieved on April 10, 2010. First oil was achieved on December 10, 2010. The transfer of ownership of hydrocarbons to the Syria government is governed under the terms and conditions of the PSC and related sales agreements.

Located in the Central Syrian Gas Basin, Ebla includes the Ash Shaer and Cherrife development areas, which cover more than 300,000 acres (approximately 1,251 square kilometres) combined. The Ebla development comprises the gas producing wells, a gas gathering and compression station, approximately 80 kilometres of pipeline and a gas treatment plant. The facility is designed to produce 80 MMcf/d of natural gas, along with related liquefied petroleum gas (LPG) and condensate volumes. Natural gas is delivered into the Syrian national gas grid for domestic consumption. LPG volumes are delivered via truck to major Syrian cities. Condensate and oil are transported to the Banias refinery in Syria.

In 2010, Suncor's share of production in Syria averaged 11,600 boe/d.

Trinidad and Tobago

On August 5, 2010, the company completed the sale of its Trinidad and Tobago assets. Prior to the sale, Suncor's share of Trinidad and Tobago production averaged 11,300 boe/d.

Principal Products

Sales of crude oil and NGLs represented 92% and sales of natural gas represented 8% of International and Offshore's consolidated operating revenues. Information on daily sales volumes and the corresponding percentage of International and Offshore's operating revenues by product for 2010, 2009 and the final five months of 2009 are as follows:

Product:	Year ended December 31, 2010		Year ended December 31, 2009	
	Mboe/d	% of operating revenues	Mboe/d	% of operating revenues
Crude oil and NGLs	179.6	92	66.8	95
Natural gas	21.5	8	8.1	5
Total	201.1		74.9	

Product:	Five months ended December 31, 2009 (1)	
	Mboe/d	% of operating revenues
Crude oil and NGLs	159.5	95
Natural gas	19.3	5
Total	178.8	

(1) Reflects operations subsequent to the Petro-Canada merger on August 1, 2009.

Sales of Conventional Crude Oil and Natural Gas

We do not typically enter into long-term supply arrangements for our East Coast Canada or North Sea production. Instead, this production is generally sold under spot contracts or under contracts that can be terminated on relatively short notice.

Approximately 20,000 bpd of Suncor's share of Hibernia production was sold to our Montreal refinery.

Hydrocarbons produced in Libya are marketed by the Libya government on behalf of Suncor.

The transfer of ownership of hydrocarbons to the Syria government is governed under the terms and conditions of the PSC and related sales agreements.

Competitive Conditions

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

Seasonal Impacts

The primary seasonal International and Offshore impacts are caused by winter storms, pack ice, icebergs and fog offshore Newfoundland and Labrador. During the winter storm season (October to March), we may have to reduce production rates at our offshore facilities as a result of limited storage capacity and the inability to offload to shuttle tankers due to wave height restrictions. We also experience seasonal impacts in the spring period, due to pack ice and icebergs drifting in the area of our offshore facilities. We have had precautionary shut-in of FPSO production and drilling delays due to pack ice and icebergs. In late spring and early summer, fog also impacts our ability to transfer personnel to the offshore facilities by helicopter.

Environmental Compliance

For a discussion of environmental risks for our International and Offshore operations, refer to "Government Regulation" in the Risk Factors section of this AIF.

Refining and Marketing

The Refining and Marketing business:

- Owns and operates refineries in Edmonton, Alberta, Montreal, Quebec, Sarnia, Ontario and Commerce City, Colorado, with a total crude oil capacity of 443,000 bpd.
- Owns and operates a lubricants plant in Mississauga, Ontario.
- Owns a joint venture interest in a petrochemical plant in Montreal, Quebec.
- Owns and operates and has equity interests in pipeline systems in Canada and the U.S.
- Owns and operates a network of distribution terminals across Canada and in Colorado.
- Markets refined products to retail, commercial and industrial customers, primarily in Canada and Colorado, through a combination of company-owned, branded-dealer and joint venture-operated retail stations, a large Canadian national commercial road transportation network and a bulk sales channel.

Refining and Product Supply Operations

Eastern North America

Our Montreal refinery has a current crude oil capacity of 130,000 bpd and produces gasoline, distillates, asphalts, heavy fuel oil, petrochemicals and solvents, which are distributed primarily across Quebec and Ontario. The Montreal refinery also produces feedstock for our lubricants plant.

The Montreal refinery processes primarily foreign conventional crude oil and has a flexible configuration that allows processing of a variety of crude oils, including heavy grades and intermediate feedstocks. Crude oil is procured from the market on a spot basis or under contracts that can be terminated on short notice.

Suncor holds a 51% interest in ParaChem Chemicals L.P. (ParaChem), which owns and operates a petrochemicals plant located adjacent to the Montreal refinery. The plant primarily produces up to 350,000 metric tons per year of paraxylene, which is used to manufacture polyester textiles and plastic bottles. ParaChem also produces benzene, hydrogen and heavy aromatics.

Our Sarnia refinery has a current crude oil capacity of 85,000 bpd and produces gasoline, distillates, and petrochemicals, which are primarily distributed in Ontario. On December 31, 2010, the company terminated its joint venture partnership with Sun Petrochemicals Company, a Toledo, Ohio-based refinery, which managed the sale of petrochemicals from Sarnia. These petrochemical sales will now be marketed solely by Refining and Marketing.

The Sarnia refinery processes both SCO and conventional crude oil. In 2010, we refined 68,000 bpd of SCO, of which 31,300 bpd was supplied from our Oil Sands operations. In the event of a significant disruption in the supply of SCO, the Sarnia refinery has the flexibility to substitute other sources of sweet or sour conventional crude oil. The balance of the refinery's feedstocks are purchased from third parties on a spot basis or under contracts that can be terminated on short notice.

To maintain supply and demand balance, Suncor imports and exports feedstocks and finished products from the East Coast. Suncor also enters into reciprocal exchange arrangements with other refining companies in Eastern North America as a means of minimizing transportation costs, balancing product availability and leveraging our assets.

Our lubricants plant produces specialty lubricants and waxes that are marketed in Canada and internationally. Suncor's lubricants plant is the largest producer of lubricant base stocks in Canada, with annual base oil production capacity in excess of 900 million litres. Feedstock for our lubricants facility comes from our Montreal refinery and other purchase contracts.

Western North America

Our Edmonton refinery has a current crude oil capacity of 135,000 bpd and primarily produces gasoline and distillates, the majority of which are distributed in Western Canada.

The Edmonton refinery has the potential to run entirely on feedstocks sourced from Alberta's oil sands and heavy crude oil production. Feedstock is supplied from Suncor's Oil Sands operations, Syncrude operations (including volumes purchased by Suncor from other joint owners' share of production) and other producers from the Athabasca and Cold Lake regions of Alberta. The refinery can upgrade directly 35,000 bpd of blended feedstock (comprised of 25,000 bpd of bitumen and 10,000 bpd of diluent) and process 45,000 bpd of sour SCO. The refinery can also process 55,000 bpd of sweet SCO through its synthetic train.

Our Commerce City refinery has a current combined crude distillation capacity of 93,000 bpd and produces primarily gasoline, diesel and asphalt. The majority of the refined products from the refinery are distributed to industrial, commercial, wholesale, and refining customers in Colorado. The remaining production is sold through a retail distribution network in Colorado.

The Commerce City refinery processes conventional crude oil and after the completion of our diesel desulphurization and oil sands integration projects, the refinery is now capable of processing up to 15,000 bpd of sour SCO from Suncor's Oil Sands operations. 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. A majority of crude feedstock is supplied from sources in the U.S., primarily the Rocky Mountain region, while the remainder is purchased from Canadian sources. The crude oil purchase contracts have terms ranging from month-to-month to multi-year.

To maintain supply and demand balance, Suncor imports and exports feedstocks and finished products from the West Coast. Suncor also enters into reciprocal exchange arrangements with other refining companies in western North America as a means of minimizing transportation costs, balancing product availability and leveraging our assets.

The following table summarizes the crude feedstock and utilizations for Suncor's refineries for the year ended December 31, 2010.

Refinery	2010 Average Daily Crude Input				
	Average Daily Crude Input Mbbls/d	Conventional Mbbls/d	Synthetic Mbbls/d	Oil Sands Synthetic Mbbls/d	Utilization %
Montreal	121.5	121.5	—	—	94
Sarnia	70.5	2.3	36.9	31.3	83
Edmonton	118.6	25.9	39.6	53.1	88
Commerce City	99.0	89.3	—	9.7	106

Transportation and Distribution

Eastern North America

Crude oil for the Montreal refinery is largely supplied by the Portland-Montreal Pipeline, in which Suncor has a 24% ownership interest. Refined products are distributed via the Trans-Northern Pipeline (33% ownership interest) and also by truck, rail and marine vessel.

Crude oil is supplied to the Sarnia refinery primarily via the Enbridge system. We procure conventional crude oil feedstock primarily from Western Canada, but periodically supplement supply with purchases from the U.S. and other countries. Foreign crude oil is delivered to Sarnia via the Enbridge Pipeline system from Montreal. We have not made any firm capacity commitments on these pipeline systems. Refined products are distributed via the Sun-Canadian Pipeline (55% ownership interest), delivering to core markets in Ontario via terminal facilities in Toronto, Hamilton and London, and also via marine vessel and rail. The Sarnia refinery also has limited access to pipelines delivering refined product into the U.S.

Western North America

Crude oil is supplied to the Edmonton refinery via third-party pipelines. Refined products are distributed via the Alberta Products Pipeline (35% ownership interest), the TransMountain Pipeline, and the Enbridge Pipeline system. Refined product also moves to distribution terminals via truck and rail.

Approximately 60% of crude oil supplied to the Commerce City refinery is transported via pipeline, with the remainder transported via truck. Refined products are distributed by truck and rail, a jet fuel pipeline to the Denver International Airport and a diesel pipeline to the Union Pacific railroad yard in Denver.

In the U.S., Suncor owns and operates the Rocky Mountain Crude Pipeline system, which runs from Guernsey, Wyoming to Denver, Colorado. This is a common carrier pipeline that transports crude for our refinery as well as for other shippers. We also own and operate the Centennial Pipeline, which transports crude from Guernsey, Wyoming to Cheyenne, Wyoming.

Refining and Marketing owns and operates 13 major refined products terminals across Canada and two product terminals in Colorado. Combined with access to facilities under long-term contractual arrangements with other parties, Suncor's North American assets are sufficient to meet Refining and Marketing's current storage and distribution needs.

Marketing Operations

Suncor's retail service station network operates nationally under the Petro-Canada$_{TM}$ brand. Most of Suncor's owned and operated Sunoco$_{TM}$-branded retail and cardlock sites were re-branded to the Petro-Canada$_{TM}$ brand in 2010. In addition to marketing through our proprietary retail outlets, petroleum product is marketed through independent dealers and joint venture facilities. In conjunction with the merger with Petro-Canada, the Canadian Competition Bureau required Suncor to divest 104 retail sites in Ontario, which was successfully completed during 2010.

As at December 31, 2010, Suncor's branded retail service station network consisted of 1,457 outlets across Canada. Our network had annual sales of gasoline motor fuels averaging approximately 5.1 million litres per site in 2010, and attracted a 19% share of the national retail market (based on data available from Statistics Canada for the period from January to October 2010). Our Colorado retail network consisted of 44 outlets owned by Suncor.

Retail Sites:	As at December 31,	
Canada	2010	2009
Petro-Canada$_{TM}$-branded retail service stations	1,447	1,318
Sunoco$_{TM}$-branded retail service stations	10	280
Total branded retail service stations	1,457	1,598
Colorado		
Shell®-branded retail service stations	37	37
Phillips 66®-branded retail service stations	7	7
Total retail service stations	44	44

Suncor has product supply agreements with an additional 178 Shell®-branded sites and 73 Phillips 66®-branded sites in Colorado. We also generate non-petroleum revenues from convenience stores, car washes, and automotive repair and maintenance services.

Suncor's wholesale operations sell petroleum products into farm, home heating, paving, small industrial, commercial and truck markets. Through our Petro-Pass network, we are the leading national marketer to the commercial road transport segment in Canada. We also sell large volumes of petroleum products directly to large industrial and commercial customers and independent marketers.

Wholesale Sites:	As at December 31,	
Canada	2010	2009
Petro-Canada$_{TM}$-branded cardlock sites (Petro-Pass)	249	235
Sunoco$_{TM}$-branded cardlock sites	—	49
	249	284

Principal Products

Daily sales volumes and corresponding percentages of Refining and Marketing's operating revenues for the last two years are as follows:

Product:	2010		2009	
	thousands of m^3/d	% of operating revenues	thousands of m^3/d	% of operating revenues
Gasoline (1)				
Eastern North America	22.2		14.6	
Western North America	18.9		13.0	
	41.1	48	27.6	52
Distillates (2)				
Eastern North America	12.4		8.8	
Western North America	18.5		9.5	
	30.9	36	18.3	33
Other (3)				
Eastern North America	10.7		4.3	
Western North America	5.1		4.7	
	15.8	16	9.0	15
Total	87.8		54.9	

(1) Includes motor and aviation gasoline.
(2) Includes diesel oils, heating oils and aviation jet fuels.
(3) Includes heavy fuel oil, asphalts, lubricants, LPG, petrochemical feedstock and other petroleum and non-petroleum products.

Product:	Five months ended December 31, 2009 (1)	
	thousands of m^3/d	% of operating revenues
Gasoline (2)		
Eastern North America	23.0	
Western North America	18.9	
	41.9	51
Distillates (3)		
Eastern North America	13.4	
Western North America	15.4	
	28.8	34
Other (4)		
Eastern North America	6.9	
Western North America	7.2	
	14.1	15
Total	84.8	

(1) Reflects operations subsequent to the Petro-Canada merger on August 1, 2009.
(2) Includes motor and aviation gasoline.
(3) Includes diesel oils, heating oils and aviation jet fuels.
(4) Includes heavy fuel oil, asphalts, lubricants, LPG, petrochemical feedstock and other petroleum and non-petroleum products.

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 business operations, refer to "Government Regulation" in the Risk Factors section of this AIF.

Other Suncor Businesses

Renewable Energy

Suncor's renewable energy interests include four wind power projects, with two more projects currently under construction, and Canada's largest ethanol plant by production volume.

Wind power is one of the most economically recognized forms of green power. Suncor is a Canadian pioneer in wind power with investments in four wind farms in operation, which have a gross generating capacity of 147 MW and reduce carbon dioxide (CO_2) emissions by approximately 284,000 tonnes each year. Suncor does not operate any of these wind farms. Two additional wind farm projects, Wintering Hills and Kent Breeze are under construction and will be operated by Suncor.

Wind Farm	Location	Ownership Interest	Size (MW)	Turbines	Commissioned
Ripley	Ripley, Ontario	50.0%	76	38	2007
Chin Chute	Taber, Alberta	33.3%	30	20	2006
Magrath	Magrath, Alberta	33.3%	30	20	2004
SunBridge	Gull Lake, Saskatchewan	50.0%	11	17	2002

Biofuels

Since 2006, Suncor has invested in Canada's emerging biofuels industry. Suncor operates Canada's largest ethanol facility, the St. Clair Ethanol Plant in the Sarnia-Lambton region of Ontario. Our ethanol plant had an original production capacity of 200 million litres per year, which has since doubled with the completion of the plant expansion on January 22, 2011. Feedstock for the plant will consist of approximately 40 million bushels of corn annually following the expansion. In 2010, the plant produced 206 million litres of ethanol.

Energy Trading

Our Energy Trading business is organized around four main commodity groups – crude oil, natural gas, sulphur and petroleum coke. Each commodity group provides value to customers through innovative commodity supply, transportation and pricing solutions. Our customers include mid- to large-sized commercial and industrial consumers, utility companies and energy producers, all of which demand specialized solutions to meet unique energy requirements.

Significant Policies

Suncor has adopted a Stakeholder Relations Policy which reflects Suncor's values and beliefs. The policy provides that Suncor is committed to developing and maintaining positive, meaningful relationships with stakeholders in all of its operating areas and provides Suncor's principles for guiding the development of stakeholder relations (respect, responsibility, transparency, timeliness and mutual benefit). The policy makes it clear that successful stakeholder engagement fosters informed decision making, resolving issues with timely, cost-effective and mutually beneficial solutions and supporting shared learning.

Suncor has adopted an Aboriginal Affairs Policy, which affirms Suncor's desire to work in collaboration with Canada's Aboriginal peoples to develop a thriving energy industry that allows Aboriginal communities to be vibrant, diversified and sustainable. The policy provides a consistent approach to the company's relationships with Canada's Aboriginal peoples and outlines Suncor's responsibilities and commitments, and is intended to guide Suncor's business decisions on a day-to-day basis. Suncor is committed to work closely with Canada's Aboriginal peoples and communities to build and maintain effective, long-term and mutually beneficial relationships. The policy makes it clear that responsible development takes into account Aboriginal issues and concerns about the effects, positive and negative, of energy development on communities and their traditional and current uses of lands and resources.

Suncor is in the process of finalizing specific guidelines for each of the Stakeholder Relations Policy and the Aboriginal Affairs Policy. During 2011, Suncor plans to hold training and awareness events which are expected to assist in continuing to affect the policies across the company.

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 March 3, 2011, with an effective date of December 31, 2010. The preparation date of the information is February 16, 2011.

Disclosure of Reserves Data

As a Canadian issuer, Suncor is 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). For the year ended December 31, 2009, Suncor applied for, and received, an exemption from Canadian securities regulatory authorities permitting Suncor to report its reserves as at December 31, 2009 in accordance with the rules and regulations of the United States Securities and Exchange Commission. Suncor did not apply for a similar exemption order for the year ended December 31, 2010. As a result, closing balances presented in 2009 have been restated (compared to those presented in our December 31, 2009 statement of reserves data and other information) to comply with NI 51-101.

The reserves data set forth below for Suncor's Canadian mining and in situ operations is based upon an evaluation conducted by GLJ Petroleum Consultants Ltd. (GLJ) with an effective date of December 31, 2010, contained in their reports (the GLJ Reports). The reserves data set forth below for all other reserves, which includes Suncor's interests in its Canadian onshore conventional (Natural Gas) and offshore conventional (East Coast Canada) assets, the North Sea of the United Kingdom (the North Sea), and Syria and Libya (collectively, Other International) is based upon evaluations or reviews conducted by Sproule Associates Limited or Sproule International Limited (collectively, Sproule) with an effective date of December 31, 2010 contained in their reports (the Sproule Reports). The reserves data reviewed by Sproule was evaluated by Suncor's internal qualified reserves evaluators. All factual data supplied to GLJ and Sproule (the Evaluators) was accepted as presented. No field inspections were conducted.

The reserves data summarizes Suncor's oil, liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs (unless otherwise indicated) prior to provision for interest, general and administrative expenses, costs associated with environmental regulations, the impact of any hedging activities or the liabilities 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. See also the "Notes to Reserves Data Tables" and the "Definitions for Reserves Data Tables"

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 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 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 "Notes to Reserves Data Tables", "Definitions for Reserves Data Tables" and "Notes to Future Net Revenues Tables" in conjunction with the following tables and notes. For more information as to the risks involved, see "Risk Factors – Uncertainty of Reserves and Resources Estimates" in this AIF.

Summary of Oil and Gas Reserves[1][2][3]
as at December 31, 2010
(forecast prices and costs)

	SCO		Bitumen		Light & Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	Bcf	Bcf	MMbbls	MMbbls
Proved Developed Producing										
Mining	2 084	1 779	—	—	—	—	—	—	—	—
In Situ	121	113	37	30	—	—	—	—	—	—
East Coast Canada	—	—	—	—	53	39	—	—	—	—
Natural Gas	—	—	—	—	10	9	953	806	8	5
Total Canada	2 205	1 892	37	30	63	48	953	806	8	5
North Sea[4]	—	—	—	—	86	86	10	10	1	1
Other International[5]	—	—	—	—	102	37	251	166	8	5
Total Proved Developed Producing	**2 205**	**1 892**	**37**	**30**	**251**	**172**	**1 214**	**982**	**16**	**11**
Proved Developed Non-Producing										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	50	47	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—	41	31	—	—
Total Canada	50	47	—	—	—	—	41	31	—	—
North Sea[4]	—	—	—	—	13	13	—	—	—	—
Other International[5]	—	—	—	—	32	12	—	—	—	—
Total Proved Developed Non-Producing	**50**	**47**	**—**	**—**	**45**	**25**	**42**	**32**	**—**	**—**
Proved Undeveloped										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	651	561	360	307	—	—	—	—	—	—
East Coast Canada	—	—	—	—	28	22	—	—	—	—
Natural Gas	—	—	—	—	—	—	118	109	—	—
Total Canada	651	561	360	307	28	22	118	109	—	—
North Sea[4]	—	—	—	—	19	19	1	1	—	—
Other International[5]	—	—	—	—	7	3	—	—	—	—
Total Proved Undeveloped	**651**	**561**	**360**	**307**	**54**	**44**	**120**	**110**	**—**	**—**
Proved										
Mining	2 084	1 779	—	—	—	—	—	—	—	—
In Situ	822	722	397	337	—	—	—	—	—	—
East Coast Canada	—	—	—	—	81	61	—	—	—	—
Natural Gas	—	—	—	—	10	9	1 113	946	8	5
Total Canada	2 906	2 500	397	337	91	70	1 113	946	8	5
North Sea[4]	—	—	—	—	118	118	12	12	1	1
Other International[5]	—	—	—	—	141	52	251	166	8	5
Total Proved	**2 906**	**2 500**	**397**	**337**	**350**	**241**	**1 376**	**1 124**	**17**	**11**
Probable										
Mining	542	462	37	30	—	—	—	—	—	—
In Situ	462	360	1 850	1 493	—	—	—	—	—	—
East Coast Canada	—	—	—	—	149	96	—	—	—	—
Natural Gas	—	—	—	—	7	5	374	307	3	3
Total Canada	1 003	821	1 887	1 523	155	102	374	307	3	3
North Sea[4]	—	—	—	—	57	57	4	4	—	—
Other International[5]	—	—	—	—	101	39	281	157	9	5
Total Probable	**1 003**	**821**	**1 887**	**1 523**	**313**	**198**	**660**	**468**	**13**	**8**
Proved Plus Probable										
Mining	2 626	2 240	37	30	—	—	—	—	—	—
In Situ	1 283	1 081	2 247	1 830	—	—	—	—	—	—
East Coast Canada	—	—	—	—	230	158	—	—	—	—
Natural Gas	—	—	—	—	17	14	1 488	1 253	11	7
Total Canada	3 909	3 321	2 284	1 860	247	172	1 488	1 253	11	7
North Sea[4]	—	—	—	—	175	175	16	16	1	1
Other International[5]	—	—	—	—	241	91	532	323	17	10
Total Proved Plus Probable	**3 909**	**3 321**	**2 284**	**1 860**	**663**	**439**	**2 036**	**1 592**	**29**	**19**

Please see Notes (1) through (5) at the end of the reserves data section for important information about volumes in this table.

Summary of Oil and Gas Reserves (1)(2)(3)
as at December 31, 2010
(constant prices and costs)

	SCO		Bitumen		Light & Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	Bcf	Bcf	MMbbls	MMbbls
Proved Developed Producing										
Mining	2 084	1 792	—	—	—	—	—	—	—	—
In Situ	121	115	37	30	—	—	—	—	—	—
East Coast Canada	—	—	—	—	53	40	—	—	—	—
Natural Gas	—	—	—	—	10	10	874	756	7	5
Total Canada	2 205	1 907	37	30	63	50	874	756	7	5
North Sea (4)	—	—	—	—	86	87	10	10	1	1
Other International (5)	—	—	—	—	102	37	246	166	8	5
Total Proved Developed Producing	**2 205**	**1 907**	**37**	**30**	**251**	**173**	**1 130**	**933**	**16**	**11**
Proved Developed Non-Producing										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	50	48	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—	25	20	—	—
Total Canada	50	48	—	—	—	—	25	20	—	—
North Sea (4)	—	—	—	—	13	13	—	—	—	—
Other International (5)	—	—	—	—	32	12	—	—	—	—
Total Proved Developed Non-Producing	**50**	**48**	**—**	**—**	**45**	**25**	**25**	**20**	**—**	**—**
Proved Undeveloped										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	652	577	360	318	—	—	—	—	—	—
East Coast Canada	—	—	—	—	27	21	—	—	—	—
Natural Gas	—	—	—	—	—	—	79	74	—	—
Total Canada	652	577	360	318	27	21	79	74	—	—
North Sea (4)	—	—	—	—	19	19	1	1	—	—
Other International (5)	—	—	—	—	7	3	—	—	—	—
Total Proved Undeveloped	**652**	**577**	**360**	**318**	**52**	**43**	**80**	**75**	**—**	**—**
Proved										
Mining	2 084	1 792	—	—	—	—	—	—	—	—
In Situ	822	739	397	348	—	—	—	—	—	—
East Coast Canada	—	—	—	—	79	61	—	—	—	—
Natural Gas	—	—	—	—	10	10	978	850	8	5
Total Canada	2 906	2 531	397	348	90	70	978	850	8	5
North Sea (4)	—	—	—	—	118	118	12	12	1	1
Other International (5)	—	—	—	—	140	52	246	166	8	5
Total Proved	**2 906**	**2 531**	**397**	**348**	**348**	**240**	**1 235**	**1 028**	**17**	**11**
Probable										
Mining	542	472	37	31	—	—	—	—	—	—
In Situ	462	384	1 850	1 580	—	—	—	—	—	—
East Coast Canada	—	—	—	—	150	99	—	—	—	—
Natural Gas	—	—	—	—	3	3	259	221	2	2
Total Canada	1 003	856	1 887	1 612	153	102	259	221	2	2
North Sea (4)	—	—	—	—	58	58	4	4	—	—
Other International (5)	—	—	—	—	101	41	277	157	9	5
Total Probable	**1 003**	**856**	**1 887**	**1 612**	**312**	**200**	**540**	**382**	**12**	**7**
Proved Plus Probable										
Mining	2 626	2 264	37	31	—	—	—	—	—	—
In Situ	1 283	1 124	2 247	1 928	—	—	—	—	—	—
East Coast Canada	—	—	—	—	230	160	—	—	—	—
Natural Gas	—	—	—	—	14	12	1 237	1 071	10	7
Total Canada	3 909	3 387	2 284	1 959	243	172	1 237	1 071	10	7
North Sea (4)	—	—	—	—	176	176	16	16	1	1
Other International (5)	—	—	—	—	241	92	523	323	17	10
Total Proved Plus Probable	**3 909**	**3 387**	**2 284**	**1 959**	**660**	**440**	**1 776**	**1 410**	**28**	**18**

Please see Notes (1) through (5) at the end of the reserves data section for important information about volumes in this table.

Please see "Notes to Future Net Revenue Tables" section for important information about constant prices and costs.

Reconciliation of Gross Oil Reserves (1)(2)(3)
as at December 31, 2010
(forecast prices and costs)

	SCO			Bitumen			Light & Medium Oil		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls
***December 31, 2009* (6)**									
Mining	2 202	591	2 794	—	—	—	—	—	—
In Situ	734	665	1 398	450	1 560	2 010	—	—	—
East Coast Canada	—	—	—	—	—	—	89	137	226
Natural Gas	—	—	—	—	—	—	15	6	21
Total Canada	2 936	1 256	4 192	450	1 560	2 010	104	143	247
North Sea (4)	—	—	—	—	—	—	141	70	210
United States	—	—	—	—	—	—	23	4	28
Other International (5)	—	—	—	—	—	—	125	133	258
Total	**2 936**	**1 256**	**4 192**	**450**	**1 560**	**2 010**	**393**	**350**	**743**
***Extensions & Improved Recovery* (7)**									
Mining	—	—	—	—	—	—	—	—	—
In Situ	14	(8)	6	2	6	8	—	—	—
East Coast Canada	—	—	—	—	—	—	6	2	9
Natural Gas	—	—	—	—	—	—	—	—	—
Total Canada	14	(8)	6	2	6	8	6	3	9
North Sea (4)	—	—	—	—	—	—	—	—	—
United States	—	—	—	—	—	—	—	—	—
Other International (5)	—	—	—	—	—	—	6	8	13
Total	**14**	**(8)**	**6**	**2**	**6**	**8**	**12**	**11**	**22**
***Technical Revisions* (8)**									
Mining	(29)	(50)	(79)	—	37	37	—	—	—
In Situ	91	(195)	(105)	(45)	284	239	—	—	—
East Coast Canada	—	—	—	—	—	—	12	8	20
Natural Gas	—	—	—	—	—	—	—	(2)	(2)
Total Canada	62	(245)	(184)	(45)	321	276	12	6	18
North Sea (4)	—	—	—	—	—	—	8	(6)	2
United States	—	—	—	—	—	—	—	—	—
Other International (5)	—	—	—	—	—	—	22	(40)	(18)
Total	**62**	**(245)**	**(184)**	**(45)**	**321**	**276**	**42**	**(40)**	**2**
***Discoveries* (9)**									
Mining	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	2	2
Natural Gas	—	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	2	2
North Sea (4)	—	—	—	—	—	—	—	—	—
United States	—	—	—	—	—	—	—	—	—
Other International (5)	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**2**	**2**

Please see Notes (1) through (11) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Oil Reserves[1][2][3] *(continued)*
as at December 31, 2010
(forecast prices and costs)

	SCO			Bitumen			Light & Medium Oil		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls	MMbbls
Acquisitions									
Mining	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	—	—
North Sea[4]	—	—	—	—	—	—	—	—	—
United States	—	—	—	—	—	—	—	—	—
Other International[5]	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Dispositions[10]									
Mining	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—	(2)	(1)	(2)
Total Canada	—	—	—	—	—	—	(2)	(1)	(2)
North Sea[4]	—	—	—	—	—	—	(4)	(6)	(10)
United States	—	—	—	—	—	—	(23)	(4)	(27)
Other International[5]	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**(29)**	**(11)**	**(39)**
Economic Factors[11]									
Mining	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—	(3)	3	—
Total Canada	—	—	—	—	—	—	(3)	3	—
North Sea[4]	—	—	—	—	—	—	—	—	—
United States	—	—	—	—	—	—	—	—	—
Other International[5]	—	—	—	—	—	—	—	—	—
Total							**(3)**	**3**	**—**
Production									
Mining	(89)	—	(89)	—	—	—	—	—	—
In Situ	(17)	—	(17)	(10)	—	(10)	—	—	—
East Coast Canada	—	—	—	—	—	—	(26)	—	(26)
Natural Gas	—	—	—	—	—	—	(1)	—	(1)
Total Canada	(106)	—	(106)	(10)	—	(10)	(27)	—	(27)
North Sea[4]	—	—	—	—	—	—	(27)	—	(27)
United States	—	—	—	—	—	—	—	—	—
Other International[5]	—	—	—	—	—	—	(13)	—	(13)
Total	**(106)**	**—**	**(106)**	**(10)**	**—**	**(10)**	**(67)**	**—**	**(67)**
December 31, 2010									
Mining	2 084	542	2 626	—	37	37	—	—	—
In Situ	822	462	1 283	397	1 850	2 247	—	—	—
East Coast Canada	—	—	—	—	—	—	81	149	230
Natural Gas	—	—	—	—	—	—	10	7	17
Total Canada	2 906	1 003	3 909	397	1 887	2 284	91	155	247
North Sea[4]	—	—	—	—	—	—	118	57	175
United States	—	—	—	—	—	—	—	—	—
Other International[5]	—	—	—	—	—	—	141	101	241
Total	**2 906**	**1 003**	**3 909**	**397**	**1 887**	**2 284**	**350**	**313**	**663**

Please see Notes (1) through (11) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Natural Gas and NGL Reserves (1)(2)(3)
as at December 31, 2010
(forecast prices and costs)

	Natural Gas			Natural Gas Liquids		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	Bcf	Bcf	Bcf	MMbbls	MMbbls	MMbbls
December 31, 2009 (6)						
Natural Gas and Total Canada	1 547	712	2 259	18	6	24
North Sea (4)	29	74	102	2	1	3
United States	154	26	180	—	—	—
Trinidad and Tobago	172	90	263	—	—	—
Other International (5)	341	613	953	9	19	28
Total	**2 243**	**1 515**	**3 757**	**29**	**26**	**55**
Extensions & Improved Recovery (7)						
Natural Gas and Total Canada	39	78	116	—	—	—
North Sea (4)	—	—	—	—	—	—
United States	—	—	—	—	—	—
Trinidad and Tobago	—	—	—	—	—	—
Other International (5)	—	—	—	—	—	—
Total	**39**	**78**	**116**	**—**	**—**	**—**
Technical Revisions (8)						
Natural Gas and Total Canada	161	(191)	(29)	(1)	—	(1)
North Sea (4)	6	(5)	1	(1)	(1)	(1)
United States	—	—	—	—	—	—
Trinidad and Tobago	—	1	1	—	—	—
Other International (5)	(68)	(331)	(400)	—	(9)	(10)
Total	**99**	**(526)**	**(427)**	**(2)**	**(10)**	**(12)**
Discoveries (9)						
Natural Gas and Total Canada	1	—	2	—	—	—
North Sea (4)	—	—	—	—	—	—
United States	—	—	—	—	—	—
Trinidad and Tobago	—	—	—	—	—	—
Other International (5)	—	—	—	—	—	—
Total	**1**	**—**	**2**	**—**	**—**	**—**

Please see Notes (1) through (11) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Natural Gas and NGL Reserves (1)(2)(3) *(continued)*
as at December 31, 2010
(forecast prices and costs)

	Natural Gas			Natural Gas Liquids		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	Bcf	Bcf	Bcf	MMbbls	MMbbls	MMbbls
Acquisitions						
Natural Gas and Total Canada	—	—	—	—	—	—
North Sea (4)	—	—	—	—	—	—
United States	—	—	—	—	—	—
Trinidad and Tobago	—	—	—	—	—	—
Other International (5)	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**
Dispositions (10)						
Natural Gas and Total Canada	(402)	(133)	(535)	(7)	(2)	(10)
North Sea (4)	(11)	(64)	(75)	—	—	—
United States	(151)	(26)	(177)	—	—	—
Trinidad and Tobago	(158)	(92)	(249)	—	—	—
Other International (5)	—	—	—	—	—	—
Total	**(722)**	**(315)**	**(1 036)**	**(7)**	**(2)**	**(10)**
Economic Factors (11)	—	—	—	—	—	—
Natural Gas and Total Canada	(45)	(92)	(137)	—	—	—
North Sea (4)	—	—	—	—	—	—
United States	—	—	—	—	—	—
Trinidad and Tobago	—	—	—	—	—	—
Other International (5)	1	—	1	—	—	—
Total	**(44)**	**(92)**	**(136)**	**—**	**—**	**—**
Production						
Natural Gas and Total Canada	(189)	—	(189)	(2)	—	(2)
North Sea (4)	(12)	—	(12)	—	—	—
United States	(3)	—	(3)	—	—	—
Trinidad and Tobago	(15)	—	(15)	—	—	—
Other International (5)	(22)	—	(22)	(1)	—	(1)
Total	**(241)**	**—**	**(241)**	**(3)**		**(3)**
December 31, 2010						
Natural Gas and Total Canada	1 113	374	1 488	8	3	11
North Sea (4)	12	4	16	1	—	1
United States	—	—	—	—	—	—
Trinidad and Tobago	—	—	—	—	—	—
Other International (5)	251	281	532	8	9	17
Total	**1 376**	**659**	**2 036**	**17**	**12**	**29**

Please see Notes (1) through (11) at the end of the reserves data section for important information about volumes in this table.

Notes to Reserves Data Tables as at December 31, 2010

(1) Numbers in the above tables are rounded to the nearest MMbbl or Bcf, as the case may be, and may not add due to rounding.

(2) The reserves data are based upon evaluations by GLJ and Sproule with an effective date of December 31, 2010, except for certain North Sea reserves (approximately 15% of total North Sea reserves) which were evaluated by Suncor's internal qualified reserves evaluators and reviewed by Sproule. The reserves data does not account for any planned divestitures after the effective date.

(3) See "Notes to Future Net Revenues Tables" for information on forecast and constant prices and costs.

(4) No royalty is payable on reserves in the U.K. The "Reconciliation of Gross Oil Reserves" and "Reconciliation of Gross Natural Gas and NGL Reserves" tables include Suncor's Netherlands operations, which were sold effective August 13, 2010.

(5) "Other International" reserves, which include Libya and Syria, include quantities of crude oil and natural gas, which will be produced under PSCs, which involve the company in upstream risks and rewards, but which do not transfer title of the product to the company. Under these PSCs, net proved and probable reserves have been determined using the economic interest method. See "Definitions for Reserves Data Tables" section.

(6) For the year ended December 31, 2009, Suncor presented disclosures in accordance with U.S. disclosure requirements under an exemption from Canadian securities requirements. As a result, closing balances presented in the 2009 disclosure have been restated to comply with NI 51-101, consistent with the presentation format for December 31, 2010 reserve disclosures.

(7) Extensions and Improved Recovery are additions to the reserves resulting from step-out drilling, infill drilling and installation of improved recovery schemes.

(8) Technical Revisions include changes in previous estimates, upward or downward, resulting from new technical data or revised interpretations.

(9) Discoveries are additions to reserves in reservoirs where no reserves were previously booked.

(10) Suncor sold its U.S. natural gas assets effective March 1, 2010. Suncor sold its Trinidad and Tobago assets effective August 5, 2010. Suncor sold its Netherland operations, included in "North Sea" reserves in the "Reconciliation of Gross Oil Reserves" and "Reconciliation of Gross Natural Gas and NGL Reserves" tables, effective August 13, 2010.

(11) Economic Factors are changes due to product pricing.

Definitions for Reserves Data Tables

In the tables set forth above and elsewhere in this AIF, the following definitions and other notes are applicable:

"**Gross"** means:

(a) in relation to Suncor's interest in production, reserves and contingent resources, Suncor's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interests of Suncor;

(b) in relation to wells, the total number of wells in which Suncor has an interest; and

(c) in relation to properties, the total area of properties in which Suncor has an interest.

"**Net**" means:

(a) in relation to Suncor's interest in production, reserves and contingent resources, Suncor's working interest (operating and non-operating) share after deduction of royalty obligations, plus the company's royalty interests in production, reserves or contingent resources;

(b) in relation to wells, the number of wells obtained by aggregating Suncor's working interest in each of the company's gross wells; and

(c) in relation to Suncor's interest in a property, the total area in which Suncor has an interest multiplied by the working interest owned by Suncor.

Reserves Categories

The oil, natural gas liquids and natural gas reserves estimates presented 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 Suncor's diesel sales volumes.

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

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

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.

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:

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.

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 category (proved or 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.

In the **economic interest method** used for PSCs, the contractor's (i.e. Suncor's) share of profit revenue plus cost recovery revenue is divided by the associated oil or gas price forecast to determine the contractor's net volume entitlement, or **entitlement reserves**. The entitlement reserves are then adjusted to include reserves relating to income taxes payable. Under this method, reported reserves will increase as commodity prices decrease (and vice versa), since the production barrels necessary to achieve cost recovery change with the prevailing commodity prices.

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 are 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.

Net Present Value of Future Net Revenues
as at December 31, 2010
(forecast prices and costs)

	Net Present Values of Future Net Revenue Before Income Taxes Discounted at %/year ($ millions)[1]					Unit Value[2]
	0%	5%	10%	15%	20%	$/boe
Proved Developed Producing						
Mining	66 666	39 429	25 893	18 474	14 043	14.56
In Situ	4 315	3 691	3 215	2 844	2 547	22.48
East Coast Canada	1 988	1 828	1 687	1 564	1 458	42.94
Natural Gas	4 071	2 791	2 146	1 755	1 492	14.45
Total Canada	77 041	47 740	32 941	24 636	19 540	15.62
North Sea	6 491	5 681	5 056	4 563	4 166	56.38
Other International	4 861	3 640	2 895	2 399	2 046	41.39
Total Proved Developed Producing	88 393	57 061	40 892	31 598	25 751	18.02
Proved Developed Non-Producing						
Mining	—	—	—	—	—	—
In Situ	1 896	1 472	1 168	945	779	24.80
East Coast Canada	—	—	—	—	—	—
Natural Gas	80	55	40	30	23	7.45
Total Canada	1 976	1 527	1 209	976	802	23.01
North Sea	991	756	599	490	411	46.58
Other International	1 109	620	374	239	158	31.33
Total Proved Developed Non-Producing	4 076	2 903	2 182	1 705	1 371	28.22
Proved Undeveloped						
Mining	—	—	—	—	—	—
In Situ	27 109	12 318	6 152	3 272	1 781	7.09
East Coast Canada	973	810	685	588	511	31.07
Natural Gas	308	186	113	68	38	6.19
Total Canada	28 390	13 314	6 950	3 928	2 330	7.65
North Sea	1 404	1 141	951	810	702	49.88
Other International	197	137	99	72	52	31.57
Total Proved Undeveloped	29 991	14 592	8 001	4 810	3 084	8.59
Proved						
Mining	66 666	39 429	25 893	18 474	14 043	14.56
In Situ	33 320	17 481	10 536	7 061	5 107	9.95
East Coast Canada	2 961	2 638	2 371	2 151	1 968	38.67
Natural Gas	4 459	3 032	2 300	1 853	1 554	13.35
Total Canada	107 406	62 580	41 100	29 540	22 672	13.38
North Sea	8 886	7 578	6 607	5 863	5 278	54.32
Other International	6 167	4 396	3 368	2 710	2 257	39.61
Total Proved	122 460	74 554	51 075	38 113	30 208	15.58
Probable						
Mining	24 854	8 447	3 272	1 402	653	6.65
In Situ	77 617	22 472	7 940	3 065	1 065	4.29
East Coast Canada	7 033	5 204	4 028	3 232	2 672	41.75
Natural Gas	1 835	836	461	280	176	7.83
Total Canada	111 339	36 959	15 701	7 979	4 566	6.28
North Sea	5 041	3 436	2 501	1 912	1 515	43.35
Other International	5 775	3 415	2 221	1 554	1 149	31.73
Total Probable	122 155	43 810	20 424	11 445	7 230	7.77
Proved Plus Probable						
Mining	91 520	47 876	29 165	19 876	14 696	12.84
In Situ	110 937	39 954	18 477	10 126	6 172	6.35
East Coast Canada	9 994	7 842	6 399	5 384	4 640	40.56
Natural Gas	6 294	3 869	2 761	2 133	1 730	11.94
Total Canada	218 745	99 541	56 802	37 519	27 238	10.20
North Sea	13 927	11 014	9 108	7 775	6 794	50.79
Other International	11 942	7 813	5 590	4 264	3 406	36.06
Total Proved Plus Probable	244 614	118 368	71 500	49 558	37 438	12.11

(1) Numbers in the above table are rounded to the nearest $1MM and may not add due to rounding.
(2) Unit values are before income taxes, discounted at 10%, using net reserves.

Net Present Value of Future Net Revenues
as at December 31, 2010
(forecast prices and costs)

	Net Present Values of Future Net Revenue After Income Taxes Discounted at %/year ($ millions)[1]				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	50 377	29 410	19 145	13 580	10 281
In Situ	4 121	3 515	3 054	2 694	2 408
East Coast Canada	1 363	1 246	1 141	1 049	969
Natural Gas	3 239	2 229	1 718	1 408	1 199
Total Canada	59 100	36 401	25 058	18 731	14 857
North Sea	3 037	2 675	2 393	2 169	1 988
Other International	2 458	1 915	1 567	1 326	1 150
Total Proved Developed Producing	64 594	40 990	29 018	22 226	17 995
Proved Developed Non-Producing					
Mining	—	—	—	—	—
In Situ	1 468	1 149	921	752	625
East Coast Canada	—	—	—	—	—
Natural Gas	59	39	28	20	15
Total Canada	1 527	1 189	948	772	640
North Sea	496	388	317	268	233
Other International	399	230	144	95	65
Total Proved Developed Non-Producing	2 421	1 807	1 409	1 135	938
Proved Undeveloped					
Mining	—	—	—	—	—
In Situ	20 029	8 766	4 132	1 998	910
East Coast Canada	667	552	463	394	339
Natural Gas	228	130	73	37	14
Total Canada	20 925	9 448	4 668	2 429	1 264
North Sea	702	578	488	420	368
Other International	70	49	35	25	19
Total Proved Undeveloped	21 697	10 075	5 191	2 875	1 650
Proved					
Mining	50 377	29 410	19 145	13 580	10 281
In Situ	25 618	13 430	8 107	5 444	3 944
East Coast Canada	2 031	1 799	1 604	1 443	1 308
Natural Gas	3 526	2 399	1 819	1 466	1 228
Total Canada	81 552	47 037	30 675	21 932	16 761
North Sea	4 234	3 641	3 198	2 857	2 589
Other International	2 927	2 194	1 746	1 446	1 233
Total Proved	88 713	52 873	35 619	26 236	20 583
Probable					
Mining	19 242	6 289	2 291	884	339
In Situ	57 629	16 228	5 407	1 808	350
East Coast Canada	5 476	4 078	3 180	2 572	2 142
Natural Gas	1 367	616	332	193	114
Total Canada	83 714	27 211	11 209	5 457	2 946
North Sea	2 523	1 742	1 283	991	793
Other International	2 693	1 632	1 078	762	568
Total Probable	88 930	30 585	13 570	7 210	4 307
Proved Plus Probable					
Mining	69 619	35 699	21 436	14 464	10 620
In Situ	83 247	29 658	13 513	7 252	4 294
East Coast Canada	7 506	5 877	4 784	4 014	3 451
Natural Gas	4 893	3 015	2 151	1 659	1 342
Total Canada	165 265	74 248	41 883	27 389	19 707
North Sea	6 758	5 383	4 481	3 848	3 381
Other International	5 621	3 827	2 824	2 208	1 801
Total Proved Plus Probable	177 644	83 459	49 188	33 445	24 889

(1) Numbers in the above table are rounded to the nearest $1MM and may not add due to rounding.

Total Future Net Revenues
as at December 31, 2010
(forecast prices and costs)

(undiscounted in $ millions)[1]	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment Costs	Future Net Revenue Before Deducting Future Income Tax Expenses	Future Income Tax Expenses	Future Net Revenue After Deducting Future Income Tax Expenses
Proved Developed Producing								
Mining	226 272	33 812	81 027	44 767	—	66 666	16 290	50 377
In Situ	13 339	1 103	6 605	1 268	48	4 315	195	4 121
East Coast Canada	4 763	1 192	1 107	220	256	1 988	625	1 363
Natural Gas	8 186	1 105	2 856	22	131	4 071	832	3 239
Total Canada	252 561	37 212	91 596	46 277	435	77 041	17 942	59 100
North Sea	8 268	—	1 439	60	278	6 491	3 455	3 037
Other International	6 844	493	1 302	170	15	4 861	2 403	2 458
Total Proved Developed Producing	267 672	37 705	94 336	46 507	728	88 393	23 800	64 594
Proved Developed Non-Producing								
Mining	—	—	—	—	—	—	—	—
In Situ	4 959	290	2 272	488	13	1 896	428	1 468
East Coast Canada	—	—	—	—	—	—	—	—
Natural Gas	267	53	113	20	1	80	21	59
Total Canada	5 226	343	2 385	508	15	1 976	449	1 527
North Sea	1 274	—	283	—	—	991	496	496
Other International	1 341	11	142	71	9	1 109	709	399
Total Proved Developed Non-Producing	7 840	353	2 809	579	24	4 076	1 654	2 421
Proved Undeveloped								
Mining	—	—	—	—	—	—	—	—
In Situ	105 768	15 301	38 693	24 198	466	27 109	7 079	20 029
East Coast Canada	2 658	609	579	466	31	973	306	667
Natural Gas	819	60	201	231	19	308	80	228
Total Canada	109 245	15 970	39 473	24 895	516	28 390	7 464	20 925
North Sea	1 803	—	291	86	24	1 404	702	702
Other International	311	7	20	85	1	197	127	70
Total Proved Undeveloped	111 359	15 976	39 783	25 066	541	29 991	8 294	21 697
Proved								
Mining	226 272	33 812	81 027	44 767	—	66 666	16 290	50 377
In Situ	124 067	16 695	47 570	25 954	527	33 320	7 703	25 618
East Coast Canada	7 421	1 801	1 686	686	287	2 961	931	2 031
Natural Gas	9 272	1 217	3 170	274	152	4 459	933	3 526
Total Canada	367 032	53 525	133 453	71 681	967	107 406	25 857	81 552
North Sea	11 345	—	2 011	146	302	8 886	4 653	4 234
Other International	8 494	510	1 464	326	26	6 167	3 239	2 927
Total Proved	386 870	54 035	136 927	72 153	1 294	122 460	33 748	88 713
Probable								
Mining	77 180	11 786	26 915	13 625	0	24 854	5 610	19 242
In Situ	240 597	48 189	72 795	41 259	736	77 617	19 988	57 629
East Coast Canada	14 773	5 172	1 166	1 307	95	7 033	1 557	5 476
Natural Gas	4 193	673	1 396	268	21	1 835	468	1 367
Total Canada	336 743	65 820	102 272	56 459	852	111 339	27 623	83 714
North Sea	6 046	—	796	180	29	5 041	2 518	2 523
Other International	7 852	695	969	410	3	5 775	3 082	2 693
Total Probable	350 641	66 515	104 037	57 049	884	122 155	33 223	88 930
Proved Plus Probable								
Mining	303 452	45 598	107 942	58 392	—	91 520	21 900	69 619
In Situ	364 663	64 884	120 365	67 213	1 263	110 937	27 690	83 247
East Coast Canada	22 194	6 973	2 852	1 993	382	9 994	2 488	7 506
Natural Gas	13 464	1 891	4 565	542	173	6 294	1 401	4 893
Total Canada	703 773	119 346	235 724	128 140	1 818	218 745	53 479	165 265
North Sea	17 391	—	2 807	326	331	13 927	7 170	6 758
Other International	16 347	1 205	2 433	735	29	11 942	6 321	5 621
Total Proved Plus Probable	737 511	120 551	240 964	129 201	2 178	244 614	66 969	177 644

(1) Numbers in the above table are rounded to the nearest $1MM and may not add due to rounding.

Future Net Revenues by Production Group
as at December 31, 2010
(forecast prices and costs)

Future Net Revenue Before Income Taxes Discounted at 10%/year	$ millions [1]	$/boe [2]
Proved		
Unconventional – Mining	25 893	14.56
Unconventional – In Situ	10 536	9.95
Total Unconventional [3]	36 429	12.84
Light and Medium Oil [4]	11 398	47.16
Natural Gas [5]	3 248	17.35
Total Proved	51 075	15.58
Proved Plus Probable		
Unconventional – Mining	29 165	12.84
Unconventional – In Situ	18 477	6.35
Total Unconventional [3]	47 642	9.19
Light and Medium Oil [4]	19 466	44.36
Natural Gas [5]	4 393	16.56
Total Proved Plus Probable	71 500	12.11

(1) Numbers in the above table are rounded to the nearest $1MM and may not add due to rounding.

(2) Per unit values use net reserves.

(3) Total Unconventional includes SCO and bitumen.

(4) Light and Medium Oil includes associated byproducts including solution gas and NGLs.

(5) Natural gas includes associated byproducts including oil and NGLs.

Notes to Future Net Revenues Tables

Prices

Forecast prices and costs

Crude oil, natural gas and other important benchmark reference pricing, as well as inflation and exchange rates utilized in the GLJ Reports and the Sproule Reports, are as per GLJ's price forecast dated January 1, 2011, as set out below. To the extent that there are fixed or presently determinable future prices or costs to which Suncor is legally bound by contractual or other obligations to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs have been incorporated into the forecast prices as applied to the pertinent properties. The forecast cost and price assumptions include increases in wellhead selling prices, take into account inflation with respect to future operating and capital costs and assume the continuance of current laws and regulations. Price adjustments relating to factors such as product quality and transportation were applied on an individual property basis in cash flow calculations.

Forecast prices also included a $Cdn/$US exchange rate of 1.02, a $Cdn/Euro exchange rate of 1.35 and a $Cdn/GBP exchange rate of 1.60. Forecast costs included a 2% inflation factor, except for costs for mining operations, which included 4% inflation for 2012-2014, 3% inflation for 2015 and 2% thereafter.

Constant Prices and costs

Benchmark prices utilized for the purpose of disclosing supplementary reserves estimates under constant pricing assumptions are also set out in the table below. Prices are based on the unweighted arithmetic average of the first-day-of-the-month price for the product for each month of 2010.

Prices used in Reserves Tables[1]

Year	NYMEX WTI[2] Crude Oil at Cushing, Oklahoma	Light Sweet[3] Crude Oil (40 API, 0.3%S) at Edmonton	WCS[4] Stream Quality at Hardisty	Edmonton[5] Pentanes Plus	Brent Blend[6] Crude Oil FOB North Sea	Natural Gas[7] at AECO	National[8] Balancing Point (U.K.)
Forecast	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	US$/bbl	Cdn$/MMbtu	Cdn$/MMbtu
2011	88.00	86.22	74.98	90.54	88.50	4.16	9.03
2012	89.00	89.29	74.95	91.96	88.25	4.74	9.01
2013	90.00	90.92	74.13	92.74	88.50	5.31	9.03
2014	92.00	92.96	75.23	94.82	90.50	5.77	9.23
2015	95.17	96.19	77.84	98.12	93.67	6.22	9.56
2016	97.55	98.62	79.79	100.59	96.05	6.53	9.80
2017	100.26	101.39	82.02	103.42	98.76	6.76	10.08
2018	102.74	103.92	84.05	106.00	101.24	6.90	10.33
2019	105.45	106.68	86.28	108.82	103.95	7.06	10.61
2020	107.56	108.84	88.01	111.01	106.06	7.21	10.82
2021+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr
Constant	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	US$/bbl	Cdn$/MMbtu	Cdn$/MMbtu
All	79.43	79.46	68.07	84.10	79.22	4.03	6.66

(1) Each price from the GLJ forecast was adjusted for quality differentials and transportation costs applicable to the specific product group and country or area of production.

(2) Price used when determining SCO reserves presented as In Situ and Mining reserves.

(3) Price used when determining light and medium oil reserves presented as Natural Gas reserves.

(4) Price used when determining bitumen reserves presented as In Situ reserves.

(5) Price used when determining diluent costs associated with bitumen reserves presented as In Situ reserves. A bitumen/diluent ratio of 2:1 was assumed.

(6) Price used when determining light and medium oil reserves presented as East Coast Canada reserves, North Sea reserves and Other International reserves.

(7) Price used when determining natural gas reserves presented as Natural Gas reserves for Canada. Price also used when determining natural gas input costs for the production of SCO and bitumen reserves.

(8) Price used when determining natural gas reserves presented as North Sea reserves and Other International reserves.

Prices Realized

For prices realized by Suncor during 2010, please see the Production History section contained within this Statement of Reserves Data and Other Oil and Gas Information.

Future Development Costs
as at December 31, 2010
(forecast prices and costs)

The following table sets forth development costs deducted in the estimation of Suncor's future net revenue attributable to the reserves categories noted below as at December 31, 2010.

($ millions) (1)	2011	2012	2013	2014	2015	Remainder	Total	10% Discounted
Proved								
Mining	2 153	2 122	1 781	1 746	1 736	35 229	44 767	19 133
In Situ	1 338	667	745	711	984	21 509	25 954	9 608
East Coast Canada	198	140	114	53	47	136	689	538
Natural Gas	112	37	31	17	25	53	274	220
Total Canada	3 802	2 966	2 670	2 527	2 792	56 926	71 684	29 499
North Sea	131	9	2	2	1	2	146	137
Other International	192	78	31	9	9	5	326	291
Total Proved	4 124	3 053	2 704	2 538	2 802	56 934	72 155	29 927
Proved Plus Probable								
Mining	2 205	2 211	1 889	2 018	2 363	47 706	58 392	22 565
In Situ	1 793	1 780	1 535	2 997	1 654	57 455	67 213	18 925
East Coast Canada	329	196	432	278	75	685	1 995	1 327
Natural Gas	261	98	63	41	25	53	542	459
Total Canada	4 589	4 285	3 919	5 334	4 117	105 898	128 142	43 276
North Sea	179	141	2	2	1	2	326	301
Other International	207	167	33	9	9	310	735	535
Total Proved Plus Probable	4 975	4 593	3 954	5 345	4 127	106 210	129 203	44 112

(1) Numbers in the above table are rounded to the nearest $1MM and may not add due to rounding.

Management currently believes internally generated cash flows, proceeds from other planned asset divestitures, proceeds from the agreement with Total and existing credit facilities are sufficient to fund future development costs. There can be no guarantee that funds will be available or that Suncor will allocate funding to develop all of the reserves attributed in the GLJ Reports and the Sproule Reports. 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. Suncor does not anticipate that interest or other funding costs would make development of any property uneconomic.

Additional Information Relating to Reserves Data

Gross Proved Undeveloped Reserves
(forecast prices and costs)

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

	Prior		2008		2009		2010	
	First Attributed [1]	Total at [2] Dec. 31, 2007	First Attributed [1]	Total at [2] Dec. 31, 2008	First Attributed [1][3]	Total at [2] Dec. 31, 2009	First Attributed [1]	Total at [2] Dec. 31, 2010
SCO (MMbbls)								
Mining	—	—	—	—	—	—	—	—
In Situ	704	704	63	766	121	564	14	651
Total SCO	704	704	63	766	121	564	14	651
Bitumen (MMbbls)								
Mining	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	427	2	360
Total Bitumen	—	—	—	—	—	427	2	360
Light & Medium Oil (MMbbls)								
East Coast Canada	—	—	—	—	36	36	3	28
Natural Gas	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	36	36	—	28
North Sea [4]	—	—	—	—	68	68	—	19
United States	—	—	—	—	8	8	—	—
Other International [5]	—	—	—	—	—	—	6	6
Total Light & Medium Oil	—	—	—	—	112	112	9	54
Natural Gas (Bcf)								
East Coast Canada	—	—	—	—	—	—	—	—
Natural Gas	24	24	8	31	29	16	32	118
Total Canada	24	24	8	31	29	16	32	118
North Sea [4]	—	—	—	—	—	—	—	1
United States	—	—	—	—	24	24	—	—
Other International [5]	—	—	—	—	413	413	—	—
Total Natural Gas	24	24	8	31	466	453	32	120
NGLs (MMbbls)								
East Coast Canada	—	—	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	—
North Sea [4]	—	—	—	—	1	1	—	—
Other International [5]	—	—	—	—	9	9	—	—
Total NGLs	—	—	—	—	10	10	—	—
Total (mmboe)	708	708	64	771	321	1 189	31	1 085

(1) First Attributed reserves include acquisitions, discoveries and extensions pertaining to the year in which the events first occurred.

(2) Year end reserves may not reflect the summation of First Attributed reserves due to changes in reserves resulting from other factors such as economic factors, improved recovery and technical revisions, which are not reflected in this table.

(3) Undeveloped reserves first attributed in 2009 primarily include those that were acquired as a result of the merger with Petro-Canada effective August 1, 2009.

(4) In this table, "North Sea" includes properties offshore of the U.K. and properties previously held by Suncor in the Netherlands.

(5) In this table, "Other International" includes properties in Libya and Syria and properties previously held by Suncor in Trinidad and Tobago.

Gross Probable Undeveloped Reserves

(forecast prices and costs)

The table below outlines the gross 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.

	Prior		2008		2009		2010	
	First Attributed (1)	Total at (2) Dec. 31, 2007	First Attributed (1)	Total at (2) Dec. 31, 2008	First Attributed (1)(3)	Total at (2) Dec. 31, 2009	First Attributed (1)	Total at (2) Dec. 31, 2010
SCO (MMbbls)								
Mining	617	617	—	617	264	264	—	215
In Situ	1 792	1 792	—	1 746	174	595	6	400
Total SCO	2 409	2 409	—	2 363	438	859	6	615
Bitumen (MMbbls)								
Mining	—	—	—	—	—	—	—	37
In Situ	—	—	—	—	—	1 550	8	1 835
Total Bitumen	—	—	—	—	—	1 550	8	1 871
Light & Medium Oil (MMbbls)								
East Coast Canada	—	—	—	—	80	80	7	85
Natural Gas	—	—	—	—	5	5	—	4
Total Canada	—	—	—	—	85	85	7	89
North Sea (4)	—	—	—	—	35	35	—	15
United States	—	—	—	—	4	4	—	—
Other International (5)	—	—	—	—	62	62	8	11
Total Light & Medium Oil	—	—	—	—	186	186	15	114
Natural Gas (Bcf)								
East Coast Canada	—	—	—	—	—	—	—	—
Natural Gas	55	55	21	76	233	233	75	136
Total Canada	55	55	21	76	233	233	75	136
North Sea (4)	—	—	—	—	50	50	—	1
United States	—	—	—	—	12	12	—	—
Other International (5)	—	—	—	—	651	651	—	240
Total Natural Gas	55	55	21	76	946	946	75	377
NGLs (MMbbls)								
East Coast Canada	—	—	—	—	—	—	—	—
Natural Gas	—	—	—	—	1	1	—	1
Total Canada	—	—	—	—	1	1	—	1
North Sea (4)	—	—	—	—	1	1	—	—
Other International (5)	—	—	—	—	18	18	—	8
Total NGLs	—	—	—	—	20	20	—	9
Total (mmboe)	2 418	2 418	4	2 375	801	2 772	41	2 672

(1) First Attributed reserves include acquisitions, discoveries and extensions pertaining to the year in which the events first occurred.

(2) Year end reserves may not reflect the summation of First Attributed reserves due to changes in reserves resulting from other factors such as economic factors, improved recovery and technical revisions, which are not reflected in this table.

(3) Undeveloped reserves first attributed in 2009 primarily include those that were acquired as a result of the merger with Petro-Canada effective August 1, 2009.

(4) In this table, "North Sea" includes properties offshore of the U.K. and properties previously held by Suncor in the Netherlands.

(5) In this table, "Other International" includes properties in Libya and Syria and properties previously held by Suncor in Trinidad and Tobago.

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

With respect to mining and in situ reserves, which collectively constitute approximately 93% of Suncor's gross proved undeveloped reserves and 93% of Suncor's gross probable undeveloped reserves, management uses integrated plans to forecast future development. The detailed plan aligns current production, processing and pipeline capacities, 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. Reserves are developed as required to keep processing capacity full. It will take more than two years to develop the in situ proved undeveloped and probable undeveloped reserves. Suncor has delineated the reserves to a high degree of certainty through seismic data, corehole drilling and pilot well performance, thereby demonstrating a high certainty of sustaining full facility capacity for over 20 years.

With respect to conventional properties, as part of its active portfolio management process, Suncor continually reviews the economic viability of its conventional properties containing undeveloped reserves using industry standard economic evaluation techniques and our own pricing and economic environment assumptions. Through this active management process, Suncor selects some properties for further development activities, while others are held in abeyance, sold, or swapped. In developing the company's reserves, Suncor considers existing facility and gathering system capacity, capital allocation plans and remaining recoverable resources availability. Accordingly, in some cases it will take longer than two years to develop all of the currently assigned conventional reserves. With the exception of undeveloped reserves that Suncor may divest, Suncor plans to develop the majority of the conventional proved undeveloped reserves over the next five years and the majority of the conventional probable undeveloped reserves over the next seven years. Exceptions are development of some offshore properties which are limited by production facility capacity and development of some international properties constrained by daily contract quantities stipulated by PSCs.

Significant Factors or Uncertainties Affecting Reserves Data

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 technical data acquired, historical performance, pricing, economic conditions, market availability, regulatory changes, and future technology improvements. Additional technical information regarding geology, reservoir properties and reservoir fluid properties are obtained through seismic programs, drilling programs and production history and may result in upward or downward revisions to reserves. Pricing, market availability and economic conditions affect the profitability of reserves exploitation. Typically, higher prices will result in higher reserves by making more projects economically viable and extending their economic life, while lower prices will result in lower reserves. Regulatory changes, including royalty regimes and environmental regulations, cannot be predicted but may have positive or negative effects on reserves. Future technology improvements would be expected to have a favourable impact on the economics of reserves development and exploitation, and therefore result in an increase to reserves.

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

For a description of our important properties, plants, facilities and installations, see "Narrative Description of Suncor's Businesses" in this AIF.

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 oil, natural gas, and natural gas liquids from onshore reserves in western Canada, Libya and Syria and from reserves offshore Newfoundland and in the North Sea.

The following table is a summary of oil and gas wells associated with the company's reserves as at December 31, 2010:

	Oil Wells (1)				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	256	253	115	108	3 864	2 786	133	82
British Columbia	5	5	4	4	115	85	72	51
Saskatchewan	—	—	—	—	254	132	29	14
Newfoundland	58	12	1	—	—	—	—	—
North Sea	81	29	21	5	1	1	—	—
Other International	162	81	186	94	6	6	—	—
Total	562	380	327	211	4 240	3 010	234	147

(1) SAGD well pairs are counted as one well.

There are no wells associated with mining properties. Suncor has no proved non-producing reserves or probable non-producing reserves in its mining reserves.

For in situ properties, proved non-producing reserves and probable non-producing reserves are associated with wells that have been drilled within the last two years and require only minor capital for facilities to bring them on-stream.

Conventional non-producing reserves are primarily associated with i) recently drilled wells to be brought on production in 2011; ii) secondary zones forecast to be brought on stream over the next two years; iii) wells shut in due to OPEC quotas to be returned to production when quotas allow; and iv) gas production being re-injected to maintain gas cap pressure on oil producing zones until depletion of the oil zones. The majority of these reserves have been in their current non-producing state for between one and four years and are forecast to be brought on-stream within the next two years.

Properties with No Attributed Reserves

The following table is a summary of properties to which no reserves are attributed as at December 31, 2010.

Country	Gross Hectares (1)	Net Hectares
Canada	6 155 544	3 836 761
Libya	2 950 978	1 339 489
Morocco	1 995 097	1 047 426
U.S. – Alaska	1 090 949	378 783
Syria	345 194	345 194
Norway	280 931	104 380
United Kingdom	165 124	78 820
Australia (2)	113 027	—
Total Hectares	13 096 844	7 130 853

(1) For lands in which Suncor holds interests in different formations under the same surface area pursuant to separate leases, the area has been counted for each lease.

(2) Suncor has an overriding royalty interest only.

Suncor holds interests in a diverse portfolio of undeveloped petroleum assets in Canada and in several international areas (offshore Norway and the United Kingdom, onshore Alaska, Libya, Syria and Morocco). These assets range from exploration properties in a very preliminary phase of evaluation, to discovery areas where tenure to the property is held indefinitely on the basis of hydrocarbon test results, but where economic development is not currently possible or has not yet been sanctioned. In many cases where reserves are not attributed to lands containing one or more discovery wells, the key limiting factor is the lack of available production infrastructure. As part of its active portfolio management process, Suncor continually reviews the economic viability of its undeveloped properties using industry standard economic evaluation techniques and our own pricing and economic environment assumptions. Each year, as part of this active management process, some properties are selected for further development activities, while others are held in abeyance, sold, swapped or relinquished back to the mineral rights owner.

In 2011, Suncor's rights to explore, develop and exploit will expire for 322,000 net hectares in Canada. These lands are entirely attributed to our conventional properties. No land tenure expiries are scheduled to occur for either mining or in situ properties for 2011. Additionally, all of Suncor's rights to explore in Morocco will expire in 2011. Substantial portions of expiring lands may have their tenure continued beyond 2011 through the conduct of work programs and/or the payment of prescribed fees to the rights owner.

Work Commitments

The practice of governments requiring companies to pledge to carry out work commitments in exchange for the right to carry out exploration for and development of hydrocarbons is common, particularly in unexplored or lightly explored regions of the world. The following table shows the estimated values of work commitments Suncor has made in regard to the lands it holds as at December 31, 2010. These commitments run through 2013 and are primarily for conducting seismic programs and drilling exploration wells.

Country/Area	Total Work Commitments (in $ millions)	2011 Work Commitments (in $ millions)
Canada	24	—
North Sea	92	20
Other International	337	120

Forward Contracts

We may use financial derivatives to manage our exposure to fluctuations in commodity prices. A description of such instruments is provided in our annual audited consolidated financial statements and related MD&A for the year ended December 31, 2010.

As a result of the merger, Suncor holds a commitment of 85,000 Mcf/d of contract capacity on the Alliance Pipeline that expires in November 2015, which enables Suncor to transport high-energy, rich natural gas from northeastern B.C. and northwestern Alberta to the Alliance Pipeline terminus in Illinois. Subsequent to Suncor's 2010 divestitures, this commitment exceeds Suncor's production from the area. Suncor estimates its minimum commitment on the Alliance Pipeline to be approximately

US$50 million per year. Natural gas for the Alliance Pipeline commitment is expected to be supplemented by supply purchased from third parties. Deliveries to Illinois are expected to continue for the term of the contract provided the sales price in Illinois exceeds, at a minimum, the variable cost of the transportation.

Additional Information Concerning Abandonment and Reclamation Costs

The company completes an annual review of its abandonment and reclamation costs as they relate to our overall 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. Where assets have indeterminate lives or where no legal liability for reclamation exists, potential costs have been excluded from the company's abandonment and reclamation cost estimates.

At December 31, 2010, Suncor estimated its undiscounted abandonment and reclamation costs, net of estimated salvage value, for surface leases, wells, facilities and pipelines pertaining to its upstream assets to be approximately $7.3 billion (discounted at 10%, approximately $1.5 billion).

Approximately $2.2 billion has been deducted as abandonment costs in estimating the future net revenues from proved plus probable reserves. This $2.2 billion represents the abandonment obligation for approximately 8,750 net reserves wells, including a forecasted number of future wells for undeveloped reserves, for our in situ and conventional activities. Abandonment and reclamation costs included in Suncor's total that are excluded from the determination of future net revenues from proved plus probable reserves include, but are not limited to, costs related to the mining and processing of oil sands ore, the treatment of oil sands tailings, gas processing facilities, and wells to which no reserves have been assigned.

Suncor anticipates incurring approximately $426 million (2011 – $110 million, 2012 – $197 million, 2013 – $119 million) of its identified abandonment and reclamation costs during the next 3 years.

Cost estimates in this section do not include the company's estimated abandonment and reclamation costs for its Refining and Marketing assets ($100 million, undiscounted).

Tax Horizon

In 2010, Suncor was subject to cash tax in the local jurisdictions related to earnings from its North Sea and Other International production, but was not cash taxable in Canada on its Canadian earnings. Suncor's audited consolidated financial statements were prepared on the assumption that it would not be cash taxable in Canada until 2014. However, as a result of the recently announced transactions with Total, Suncor may become cash taxable in Canada by 2012.

Costs Incurred

The table below summarizes the company's capital expenditures related to its reserve activities for the year ended December 31, 2010.

(in $ millions)	Exploration Costs	Proved Property Acquisition Costs	Unproved Property Acquisition Costs	Development Costs	Total
Canada – Oil Sands	6	—	—	3 426	3 432
Canada – Conventional	63	—	38	337	438
North Sea [1]	191	—	—	319	510
United States	—	—	—	5	5
Trinidad and Tobago	3	—	—	14	17
Other International	153	—	—	364	517
Total	416	—	38	4 465	4 919

(1) In this table North Sea includes Suncor's Netherlands operations prior to their sale, effective August 13, 2010.

Exploration and Development Activities

The table below outlines the gross and net exploratory and development wells the company completed during the year ended December 31, 2010. These represent wells from both our in situ and conventional activities only, as no wells are drilled in mining activities.

Total number of wells completed (1)	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Canada				
Oil	—	—	16	13
Natural Gas	2	2	338	172
Dry	1	1	—	—
Service	4	4	8	6
Stratigraphic Test	—	—	—	—
Total	7	7	362	191
North Sea				
Oil	2	1	7	3
Natural Gas	2	1	1	1
Dry	1	1	2	1
Service	—	—	—	—
Stratigraphic Test	—	—	—	—
Total	5	3	10	5
Other International				
Oil	—	—	19	10
Natural Gas	—	—	—	—
Dry	4	4	1	1
Service	—	—	8	4
Stratigraphic Test	—	—	—	—
Total	4	4	28	15

(1) Totals include wells completed for assets and operations that were sold during the year. "North Sea" includes Netherlands. There were no wells completed in Trinidad and Tobago prior to disposition. There were nine natural gas development wells completed in the United States prior to disposition.

Suncor's most important current and likely exploration and development activities include

- In situ – During 2011, Suncor will continue the development of its in situ Firebag Stage 3 and Stage 4 assets, as well as MacKay River Phase 2.
- Natural Gas – Two significant drilling programs began in the fourth quarter of 2010: one in the Ferrier area located in central Alberta and another at Pouce Coupe in western Alberta. Tie-in activities for both programs started in the first quarter of 2011.
- East Coast Canada – The development plan for the Hibernia South Extension has been approved by the joint owners and sanction is expected in the first quarter of 2011. First oil from platform development wells is expected by mid-2011. On May 31, 2010, first oil was achieved at the North Amethyst portion of the White Rose Extensions and development drilling continues.
- North Sea – In Norway, Suncor completed its first operated exploration well and encountered hydrocarbons. An appraisal well was drilled and tested in the fourth quarter of 2010 with positive results. Further evaluation is required to determine the potential size of this discovery.
- Libya – Suncor began its operated exploration drilling program in mid-2010. The company has commitments to drill an additional 42 remaining commitment wells under its EPSAs; 14 exploration wells are planned to be drilled in 2011. Field development plans were prepared for the redevelopment of part of the Ghani field, and for the further development of the En Naga field. Redevelopment plans for the company's other fields are expected to be defined in 2011.
- Syria – In 2011, Suncor will focus on the Ash Shaer oil development area with the drilling of one well and continued investment in our oil production facilities. Technical evaluation of an oil prospect is to be completed in the first quarter and may lead to drilling of a well towards the end of the year. Within the exploration acreage of Block II, seismic work will be performed during 2011 to support drilling activities in the coming year.

Production Estimates

The table below outline the volume of the company's production of gross proved and gross proved plus probable reserves estimated for the year ending December 31, 2011, as is reflected in the estimates of gross proved reserves and gross probable reserves previously disclosed in the "Summary of Oil and Gas Reserves" tables.

	SCO (1)		Bitumen		Light & Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	Mbbls/d	Mbbls/d	Mbbls/d	Mbbls/d	Mbbls/d	Mbbls/d	MMcf/d	MMcf/d	Mbbls/d	Mbbls/d
Canada										
Total Proved	327	293	13	11	52	38	381	319	3	2
Total Probable	9	8	6	6	28	18	21	18	—	—
Total Proved Plus Probable	336	300	19	17	80	57	401	336	3	2
North Sea										
Total Proved	—	—	—	—	63	63	9	9	1	1
Total Probable	—	—	—	—	2	2	—	—	—	—
Total Proved Plus Probable	—	—	—	—	65	65	9	9	1	1
Other International										
Total Proved	—	—	—	—	37	11	80	54	3	2
Total Probable	—	—	—	—	—	—	14	9	1	—
Total Proved Plus Probable	—	—	—	—	37	11	94	64	3	2

(1) Production estimates for 2011 from Suncor's mining operations (excluding Syncrude) are 83.5 MMbbls of synthetic crude oil, approximately 36% of estimated production for 2011.

Production History

The table below outlines the company's historical production information, by product type, for each of the four financial quarters, as an average daily measure, for Canada, North Sea, the United States, Trinidad and Tobago and Other International.

	2010			
	Three months ended			
	Mar 31	Jun 30	Sept 30	Dec 31
Canada				
Oil Sands [1]				
Average Total Production (Mbbls/d)	234.6	334.4	338.3	363.8
Average Production In Situ (Mbbls/d)	87.5	88.2	79.2	85.8
Average Price Received ($/bbl)	70.32	73.73	66.73	69.52
Royalties ($/bbl)	(3.29)	(5.99)	(9.30)	(4.19)
Total Cash Operating Costs ($/bbl)	(53.37)	(35.40)	(34.38)	(36.62)
In Situ Cash Operating Costs ($/bbl)	(19.35)	(18.70)	(22.40)	(21.30)
Light & Medium Oil				
Average Production (Mbbls/d)	74.6	70.6	66.3	62.9
Average Price Received ($/bbl)	80.79	78.99	81.06	89.35
Royalties ($/bbl)	(28.78)	(28.45)	(25.49)	(29.17)
Production Costs ($/bbl)	(8.48)	(8.19)	(9.08)	(9.80)
Netback ($/bbl)	43.53	42.35	46.49	50.38
Natural Gas [2]				
Average Production (MMcfe/d)	680	586	546	438
Average Price Received ($/Mcfe)	6.14	4.94	4.63	4.47
Royalties ($/Mcfe)	(0.99)	(0.12)	(0.54)	(0.44)
Production Costs ($/Mcfe)	(1.65)	(2.00)	(2.48)	(2.04)
Netback ($/Mcfe)	3.50	2.82	1.61	1.99
North Sea [3]				
Light & Medium Oil [4]				
Average Production (mboe/d)	86.1	72.0	83.8	74.0
Average Price Received ($/boe)	73.56	77.18	77.77	86.90
Royalties ($/boe)	—	—	—	—
Production Costs ($/boe)	(7.61)	(9.95)	(7.68)	(8.35)
Netback ($/boe)	65.95	67.23	70.09	78.55
United States [5]				
Natural Gas [2]				
Average Production (MMcfe/d)	52	—	—	—
Average Price Received ($/Mcfe)	8.12	—	—	—
Royalties ($/Mcfe)	(1.32)	—	—	—
Production Costs ($/Mcfe)	(1.95)	—	—	—
Netback ($/Mcfe)	4.85	—	—	—

Please see Notes (1) through (5) at the end of the Production History table.

Production History *(continued)*

	2010			
	Three months ended			
	Mar 31	Jun 30	Sept 30	Dec 31
Trinidad and Tobago (6)				
Natural Gas				
Average Production (MMcf/d)	70	11	4	—
Average Price Received ($/Mcf)	3.09	2.75	2.09	—
Royalties ($/Mcf)	—	—	(1.43)	—
Production Costs ($/Mcf)	(0.25)	(0.40)	(0.29)	—
Netback ($/Mcf)	2.84	2.35	0.37	—
Other International				
Light & Medium Oil				
Average Production (mboe/d)	35.4	35.4	35.4	34.7
Average Price Received ($/boe)	73.92	80.61	79.66	88.03
Royalties ($/boe)	(43.28)	(41.49)	(35.56)	(14.11)
Production Costs ($/boe)	(3.81)	(6.91)	(3.11)	(4.41)
Netback ($/boe)	26.83	31.75	40.99	69.50
Natural Gas (2)(7)				
Average Production (MMcfe/d)	—	12.8	16.5	16.9
Average Price Received ($/boe)	—	65.54	65.77	71.94
Royalties ($/boe)	—	(24.54)	(24.56)	(27.09)
Production Costs ($/boe)	—	(10.53)	(9.25)	(9.42)
Netback ($/boe)	—	30.47	31.97	35.43

(1) Suncor tracks cash operating cost for its Oil Sands operations, which includes more expenses than production costs. For this reason a netback calculation is not presented in this table. Also, most of Suncor's bitumen production is upgraded, therefore a bitumen netback is not presented.
(2) Volumes include NGLs and crude oil from natural gas wells.
(3) North Sea includes Suncor's operations in the Netherlands up to the date of sale, August 13, 2010.
(4) Volumes include field production for natural gas and NGLs.
(5) Suncor sold its U.S. assets effective March 1, 2010.
(6) Suncor sold its Trinidad and Tobago assets effective August 5, 2010.
(7) Syria operations achieved first gas on April 10, 2010 and first oil on December 10, 2010.

The following table provides the production volumes for each of Suncor's important fields for the year ended December 31, 2010:

	SCO and Bitumen (1)	Light & Medium Oil	Natural Gas	Natural Gas Liquids	Total
	Mbbls/d	Mbbls/d	MMcf/d	Mbbls/d	MBoe/d
Mining – Suncor	208.2	—	—	—	208.2
Mining – Syncrude	35.1	—	—	—	35.1
Firebag	44.2	—	—	—	44.2
MacKay River	30.3	—	—	—	30.3
Terra Nova	—	23.2	—	—	23.2
Hibernia	—	30.9	—	—	30.9
White Rose	—	14.5	—	—	14.5
Buzzard	—	53.8	7.0	0.5	55.5

(1) Suncor does not distinguish which sources of bitumen are upgraded to SCO.

Contingent Resources

GLJ conducted an independent evaluation of best estimate contingent resource volumes for all of Suncor's mining properties and for Suncor's in situ properties for which GLJ evaluated reserves. For remaining in situ properties, GLJ audited Suncor's evaluation of best estimate contingent resource volumes. Best estimate contingent resources for conventional properties were prepared by Suncor's own qualified reserves evaluators in accordance with the COGE Handbook. Based on the foregoing, effective December 31, 2010, Suncor's best estimates of gross contingent resources are set out in the table below.

Best Estimate Gross Contingent Resources as at December 31, 2010 (1)(2)(3)(4)	SCO	Bitumen	Light & Medium Oil	Natural Gas	Natural Gas Liquids
	MMbbls	MMbbls	MMbbls	Bcf	MMbbls
Mining	6 050	—	—	—	—
In Situ	6 412	5 291	—	—	—
East Coast Canada	—	—	252	1 961	—
Natural Gas		—	108	7 943	11
Total Canada	12 462	5 291	360	9 904	11
North Sea (5)	—	—	106	45	—
Other International	—	—	490	287	5
U.S.	—	—	—	133	—
Total Best Estimate Gross Contingent Resources	**12 462**	**5 291**	**956**	**10 370**	**17**

(1) Numbers in the above table are rounded to the nearest MMbbl or Bcf, as the case may be, and may not add due to rounding.

(2) Volumes represent Suncor's working interest in properties with contingent resources.

(3) 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.

(4) 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.

(5) North Sea includes offshore U.K. and Norway.

Estimates of contingent resources have not been adjusted for risk based on the chance of development. There is no certainty as to the timing of such development. The economic viability of the contingent resources is dependent upon pricing and economic conditions. There is no certainty that all or any portion of the contingent resources will be commercially viable to produce. For movement of resources to reserves categories, all projects must have an economic depletion plan and may require, among other things: (i) additional delineation drilling and/or new technology for unrisked contingent resources; (ii) regulatory approvals; and (iii) company approvals to proceed with development.

Significant factors which may change the contingent resource estimates include further delineation drilling, which could change the estimates either positively or negatively, and future technology improvements, which would positively affect the estimates. Also, we have assumed that all mining and some in situ contingent resources will be upgraded and sold as SCO. To the extent that these volumes are not upgraded, but rather sold as bitumen, contingent resources volumes reported would be lower for SCO and higher for bitumen and total contingent resource volumes would be higher because of the yield factor applied to bitumen volumes when upgraded into SCO.

The contingencies which currently prevent the classification of the contingent resources as reserves include:

- the need for higher density corehole drilling to improve the certainty of in situ resources;
- the need for further facility design and the associated uncertainty in development costs and timelines;
- the preparation of firm development plans and regulatory applications (including associated reservoir studies and delineation drilling);
- regulatory approvals; and
- corporate approvals to proceed with development.

The additional facility design work, development plans, reservoir studies and delineation drilling are often completed in the course of preparing the company's application for regulatory approvals. Once all regulatory and corporate approvals are received and any other contingencies are removed, the resources may then be reclassified as reserves.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, environmental, 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, (including the governments of the United States and other foreign jurisdictions in which we operate), 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 and with similar assets. 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 and purchase agreements directly with oil purchasers. Most agreements are linked to global oil prices. Global oil prices are set by daily, weekly and monthly physical and financial transactions for crude oil around the world. Those prices are primarily based on worldwide fundamentals of supply and demand. Specific prices depend 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. In Canada, oil exporters are also entitled to enter into export contracts. If the term of an export contract exceeds one year for light crude oil or exceeds two years for heavy crude oil (to a maximum of 25 years), the exporter is required to obtain an export licence from the National Energy Board (NEB) and the issuance of such licence requires a public hearing and the approval of the Governor in Council. If the term of an export contract does not exceed one year for light crude oil or does not exceed two years for heavy crude oil, the exporter is required to obtain an order approving such export from the NEB.

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 continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) export contracts for volumes of more than 30,000 m^3/d with a term that exceeds two years (to a maximum of 25 years) require the 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. Natural gas (other than propane, butane and ethane) export contracts for volumes of more than 30,000 m^3/d with a term that does not exceed two years, or export contracts for volumes of 30,000 m^3/d or less for a term of two to 20 years, must be made pursuant to an NEB order.

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 reserves availability, transportation arrangements, and market considerations.

Internationally, prices for crude oil and natural gas fluctuate in response to changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of other factors beyond Suncor's control. These factors include, but are not limited to, the actions of the Organization of the Petroleum Exporting Countries (OPEC), world economic conditions, government regulation, political developments, the foreign supply of oil, the price of foreign imports, the availability of alternate fuel sources and weather conditions.

Pipeline Capacity

Although pipeline expansions are ongoing, the pro-rationing of capacity on the 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.

Royalties and Incentives

Canada – General

In addition to federal regulation, each province has legislation and regulations governing land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, NGLs, 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 owner's working 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.

The Canadian federal corporate income tax rate levied on taxable income is 18% effective January 1, 2010 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 and subsequently enacted, 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 1, 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. The New Royalty Framework established new royalty rates for conventional oil, natural gas and oil sands. As at January 1, 2009, the new royalty rates for conventional oil were set by a single sliding-scale formula, which were applied monthly and increased the old royalty from 30% to 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/bbl. The sliding-scale formula included 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 were set by a single sliding-scale formula ranging from 5% to 50% with a rate cap once the price of natural gas reached Cdn$16.59/gigajoule. The New Royalty Framework determined rate was 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 (discovered after 1974), and up to 35% in the case of old natural gas (discovered prior to 1974), depending upon a prescribed or corporate average reference price. The New Royalty Framework provides some royalty relief, under the Natural Gas Deep Drilling Program, for wells drilled beyond 2,000 metres true vertical depth, based on total depth and whether the well is exploratory or developmental. 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. Under this New Well Royalty Reduction Program, which became effective January 1, 2009, 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 the new transitional royalty rates, which would cap the maximum royalty at 30%. However, their wells cannot also receive relief from the Natural Gas Deep Drilling Program. In order to qualify for this program, wells must be drilled during the period starting on January 1, 2009 and ending on December 31, 2013. Following this period, all new wells drilled will automatically be subject to the New Royalty Framework.

Further changes to the New Royalty Framework were announced March 11, 2010. Effective January 1, 2011, the maximum natural gas royalty rate is reduced to 36% and the option to elect transitional royalty rates is no longer available. The New Well Royalty Reduction Program has changed such that the current 5% royalty is now a permanent rate that applies to production from oil or gas wells, gas production from shale zones, gas production from coal bed zones and production from horizontal drilled oil or gas wells subject to certain limitations. The Natural Gas Deep Drilling Program is amended for wells spudded or deepened on or after May 2010 in that: a) production from intervals greater than 2,000 metres now qualify; b) benefits from the four new well royalty reduction programs discussed above apply first; c) the terms of both programs run concurrently; and d) certain technical changes no longer disqualify wells under this program.

Oil sands projects are also subject to the New Royalty Framework and regulated by, among other legislation, the *Oil Sands Royalty Regulation, 2009* approved by the Government of Alberta on December 10, 2008. Royalties on our current Firebag and MacKay River in situ projects were under the 1997 Generic Regime until the end of 2008, and assessed based on bitumen value. 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 (Revenue – Cost), subject to a 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 (including the Suncor RAA) and assessed on the R – C difference 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 Royalty 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 operating costs and related capital costs; (c) from January 1, 2010 through December 31, 2015, pursuant to our January 2008 Suncor RAA with the Government of Alberta, the New Royalty Framework rates described above will apply in the calculation of the bitumen royalty, subject to a cap of 30% of R – C, and a minimum royalty cap of 1.2% of R. In addition, the Suncor RAA provides Suncor with a level of guidance for various matters, including the BVM (discussed below), 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, comprised of our base mining operations and our in situ projects, will be the rates prescribed under the New Royalty Framework, unless as amended or superseded prior to that time.

As part of the implementation of the New Royalty Framework, the Alberta government enacted new BVM (Ministerial) Regulations effective January 1, 2009. These interim regulations determine the valuation of bitumen for 2009 to 2011. The final regulations are being developed by the Crown that will establish the BVM calculation for future years. For Suncor's mining operations, the BVM is based on the terms of the Suncor RAA, which we believe places certain limitations on the interim BVM. For the year 2009, Suncor filed a non-compliance notice with the Crown, citing that reasonable adjustments in the determination of the Suncor bitumen value were not considered by the Crown as permitted by Suncor's RAA. For 2009 and the majority of 2010, royalty payments to the Crown for our mining operations were determined in accordance with Suncor's RAA, and royalty expense was recorded under the Crown's interim BVM. In December 2010, the Minister of Energy notified Suncor of a modification to the Suncor BVM for quality and transportation, resulting in a pre-tax adjustment to earnings of $129 million recorded as a reduction to royalty expense. Suncor filed its second non-compliance notice with the Crown, for 2009 and 2010, related to the unreasonable quality adjustments made by the Minister. Pursuant to the Oil Sands Royalty Regulations 2009, Suncor provided replacement royalty reports for 2009 and 2010 as requested by the Minister and remitted, under protest, the balance of royalty payable at the end of January 2011. Suncor's RAA provides for an arbitration procedure failing an agreed settlement of these issues, and Suncor filed a Notice of Commencement of Arbitration with the Crown on January 29, 2011. See "Government Regulation" in the Risk Factors section of this AIF.

In November 2008, the Alberta government and the Syncrude joint venture owners reached an agreement for the implementation of the New Royalty Framework for the Syncrude project (similar to Suncor's RAA). Under the new royalty terms, the project would continue paying the greater of 1% gross revenue, or 25% of net revenue, until the end of 2015. On January 1, 2016, the royalty rates under the New Royalty Framework will apply to the Syncrude project. As part of this agreement, Syncrude exercised its option to pay royalty based on bitumen revenues rather than on SCO revenues. Due to this conversion to a bitumen-based royalty, the upgrader facility at the Syncrude project will no longer be considered as part of the oil sands project. The Syncrude owners have agreed to pay a total of $1.25 billion in royalties over the next 25 years, with interest to account for deductions of allowed costs related to the upgrader facility, which were previously received. The owners also agreed to pay an additional royalty of $975 million over a six-year period starting in 2010, contingent on achieving certain production levels. Syncrude also filed a non-compliance notice with the Crown, citing that reasonable adjustments in the determination of the bitumen value were not considered by the Crown, similar to the notice filed by Suncor in respect of its RAA.

East Coast Canada

The royalty regime for the Terra Nova project has three tiers. The royalty consists of a sliding-scale basic royalty payable throughout the project's life, with two additional tiers of incremental net royalties, which are payable upon the achievement of specified levels of profitability. The basic royalty is payable as a percentage of gross field revenue, with an initial rate of 1%, which rises to 10% depending on cumulative production levels and the occurrence of simple payout. After tier one payout has been reached, including a specified return allowance, tier one net royalty will become the greater of the basic royalty, or 30% of net revenue. An additional tier two net royalty equal to 12.5% of net revenue will be payable once a further level of payout, including an additional return allowance, is attained. In 2008, Suncor reached Terra Nova tier two royalty payout and the royalty rate increased to 42.5% of net revenue from 30% of net revenue. During 2010, the Terra Nova royalty averaged 35% of gross revenue.

The royalty regime for the Hibernia project has three tiers – gross royalty, net royalty and supplementary royalty. Gross royalty increased to 5% of gross field revenue on July 1, 2003. The gross royalty rate was at 5% until net royalty payout was reached. The gross royalty is indexed to crude oil prices under certain conditions. Upon achieving payout, including a specified return allowance, the net royalty payable becomes the greater of 30% of net revenue or 5% of gross revenue. Suncor reached Hibernia 30% net royalty in 2009. After a further level of payout is reached, which includes an additional return allowance, a supplementary royalty of 12.5% of net revenue also becomes payable. In addition, Hibernia production is subject to a federal government net profits interest of up to 10% of net revenue, which commenced in the first quarter of 2009. During 2010, the Hibernia royalty and net profits interest averaged 38% of gross revenue. Also in 2010, an agreement was reached with the Province of Newfoundland and Labrador on the eligibility of transportation costs for royalty deductibility.

In July 2003, the Government of Newfoundland and Labrador published regulations for the royalty regime that will apply to the development of petroleum resources in offshore areas other than at Hibernia and Terra Nova. The generic offshore royalty regime consists of a sliding-scale basic royalty payable throughout a project's life, and a two-tier incremental net royalty payable upon the achievement of specified levels of profitability. The basic royalty is calculated as a percentage of gross field revenue, commencing at 1% and rising to 7.5%, depending on cumulative production levels and the achievement of simple payout. Upon reaching tier one payout, including a return allowance, the tier one net royalty is calculated as the greater of the basic royalty, or 20% of net revenue. An additional 10% tier two net royalty rate is payable once a higher level of return on investment is attained. In 2008, Suncor reached White Rose tier two royalty payout, and the royalty rate increased to 30% of net revenue from 20% of net revenue. In the second quarter of 2010, Suncor began to pay basic royalty of 1% on the production from the North Amethyst portion of its White Rose project. The royalty rates for the North Amethyst field follow the same scale as the rates for the White Rose base field with the exception of a super royalty of 6.5% to coincide with tier one, if WTI is greater than $50/bbl. The North Amethyst royalty remained at the 1% basic rate for 2010. Overall, the White Rose royalty averaged 25% of gross revenue during 2010.

See also "Government Regulation" in the Risk Factors section of this AIF.

Production Sharing Contracts

Amounts presented as royalties for production from our Libya and Syria operations are determined pursuant to PSCs. The amounts calculated reflect the difference between Suncor's working interest in the particular project and the net revenue attributable to Suncor under the terms of the PSC. All government interests in the operations, except for income taxes, are presented as royalties.

Suncor conducts its Libya operations pursuant to EPSAs, under which the company pays 50% of the costs and recovers these costs from 12% of production. Excess production is then shared between Suncor and the Libyan government.

In Syria, the Ebla gas project is operated pursuant to a PSC, under which the company pays 100% of the costs and recovers these costs from a 40% share of production after deduction for royalties of 12.5%. The remaining profit is shared between Suncor and the Syria government.

See also "Government Regulation" in the Risk Factors section of this AIF.

Land Tenure

In Canada, petroleum, bitumen and natural gas located in the western provinces are 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, 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. In frontier areas of Canada, the mineral rights are primarily owned by the Canadian federal government, which, either directly or through shared jurisdiction agreements with the relevant provincial authorities (for example, the CNLOPB), grant tenure in the form of exploration, significant discovery and production licences.

In Suncor's international theatres of operation, petroleum and natural gas are most commonly owned by national governments that grant rights in the form of exploration licences and permits, production licences, production sharing agreements and other similar forms of tenure. In all cases, Suncor's right to explore, develop and produce petroleum and natural gas is subject to ongoing compliance with the regulatory requirements established by the relevant country.

Environmental Regulation

The company is subject to environmental regulation under a variety of Canadian, U.S., U.K., and other foreign, federal, provincial, territorial, state and municipal laws and regulations. These regulatory regimes are laws of general application that apply to us in the same manner as they apply to other international companies and enterprises in the energy industry. The regulatory regimes require us to obtain operating licences 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 generally required before initiating most new major projects or undertaking significant changes to existing operations. In addition, such legislation requires that the company abandon and reclaim well and facility sites 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 licences and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties. In addition to these specific, known requirements, we expect future changes to environmental legislation, including anticipated legislation for air pollution (Criteria Air Contaminants) and GHG that will impose further requirements on companies operating in the energy industry.

A number of statutes, regulations and frameworks are under development or have been issued by various provincial regulators that oversee oil sands development. These statutes, regulations and frameworks relate to such issues as tailings management, water use and land use. While the financial implications of such statutes, regulations and frameworks are not yet known, the company is committed to working with the appropriate regulatory bodies as they develop new policies, and to fully complying with all existing and new statutes, regulations and frameworks as they apply to the company's operations.

In the fall of 2009, the Government of Alberta enacted the Land Stewardship Act (LSA). Pursuant to the LSA, the province is divided into seven regions for planning purposes, and each region is to be managed pursuant to a cumulative effects management approach. One of the regions set out in the LSA is the Lower Athabasca Region, which includes Suncor's Oil Sands operations. The Lower Athabasca Region Plan is anticipated to be released in 2011 and its contents may impact existing or future Suncor operations.

In general, there remains uncertainty around the outcomes 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 GHG emissions, investing in renewable forms of energy such as wind power and biofuels, accelerating land reclamation, installing new emissions abatement equipment and pursuing other opportunities such as carbon capture and sequestration.

Climate Change Regulation

Suncor operates in jurisdictions that have regulated, or have proposed to regulate, industrial GHG emissions. Those jurisdictions that have announced the intent to regulate GHG emissions generally support policies based on a carbon price, possibly through a cap-and-trade system, a tax, a hybrid of the two, and possibly including other measures such as low carbon fuel and renewable fuel standards. Suncor participates both directly and through industry associations in the consultation process on the design of proposed regulations, as well as efforts to harmonize regulations across jurisdictions within North America.

International Climate Change Agreements and Treaties

At the end of 2009, the United Nations Framework on Climate Change Conference of the Parties (UNFCC COP 15) was held in Copenhagen, Denmark. One of the major outcomes of this conference was the Copenhagen Accord. The Accord was generally accepted by the member countries at the Copenhagen summit, but is not legally binding and does not contain any binding commitments for reducing CO_2 emissions, nor does it include any discussion on compliance mechanisms. Canada subsequently committed to reducing its GHG emissions by 17% below 2005 levels by 2020, in line with the reduction commitment made by the U.S.; however, a comprehensive plan for how these reductions will be achieved has not yet been developed. The Copenhagen Accord and the Kyoto Protocol remain intact subsequent to COP 16, held in Cancun, Mexico.

Canadian Federal GHG Regulations

The Canadian federal government has started to address the emissions of specific sectors of the economy, including implementing vehicle emissions standards in line with the U.S. as well as performance standards for the electrical power generating sector. Also in line with the U.S., Canada has adopted a Renewable Fuels Standard, mandating that 5% of the gasoline supply come from renewable sources such as ethanol and biodiesel. The Canadian federal government, however, has not yet passed any broad climate change legislation. It has gone on record as saying that it will align GHG emissions legislation with the U.S. Since it remains unclear which approach the U.S. will take, it is also unclear whether, or when, the Canadian government will implement economy-wide climate change legislation, or a sector specific approach, and what type of compliance mechanisms will be available to large emitters.

Canadian Provincial GHG Regulations

In the absence of a federal GHG emissions policy, various Canadian provinces have responded with their own GHG emissions reduction targets and passed legislation enabling regulation of large final emitters. Suncor will continue to engage the appropriate governmental bodies in meaningful dialogue in an effort to develop a harmonized system which focuses on achieving actual reduction goals and sustainable resource development.

In 2007, the Alberta government introduced the *Climate Change and Emissions Management Amendment Act (Alberta)*, which places intensity (GHG emissions per unit of production) limits on facilities emitting more than 100,000 tonnes of CO_2 equivalent (CO_{2e}) per year. Suncor's Alberta facilities are subject to this legislation. The Act, which commenced July 2007, calls for intensity reductions of 12% from an established intensity baseline.

In March 2011, Suncor will file compliance reports that show what actions the company took during the year to demonstrate that each facility either met its intensity target for 2010 or took action to offset its emissions intensity. Compliance options available to Suncor include emissions reductions, utilizing Alberta-sanctioned offset projects, or contributing to Alberta's Climate Change and Emissions Management Fund (Alberta Technology Fund) at a present cost of $15/tonne. For the compliance period of January 1 to December 31, 2010, the compliance costs to Suncor are estimated to be between $5 million and $10 million. Final costs for 2010 will be determined when the company files its compliance report with the Province of Alberta in March 2011. 2010 compliance was achieved through reduced emissions per unit of production, purchase and retirement of offsets, and payments into the Technology Fund, which Suncor strongly supports as a policy option. No material changes are expected to the Alberta regulations for the coming year.

British Columbia's GHG Reduction Act came into effect on January 1, 2010. It requires reporting and verification of all large facilities emissions, and is intended as a first step towards compliance within the Western Climate Initiative (a California-lead reduction initiative with members from several U.S. states and Canadian provinces). Draft regulations for a cap-and-trade system, as well as offset regulations, have been posted by the B.C. Climate Action Secretariat, and are intended to be finalized sometime in 2011. The impact of a potential cap-and-trade system cannot be quantified, given the current lack of detail of how the system will operate. The Province of B.C. also enacted a carbon tax in 2008, which began at $10/tonne CO2, and escalates at $5 per year until 2012 when it caps out at $30/tonne. This tax is carbon neutral, in that revenues are recycled back to taxpayers via tax reductions, and is applied on consumption. Suncor currently operates natural gas production and gathering facilities in B.C.

Ontario and Quebec are also members of the Western Climate Initiative (WCI). Ontario implemented mandatory reporting regulations beginning with 2010 emissions, but has delayed action on any further GHG emissions regulations for now. Quebec is implementing mandatory reporting for large facilities beginning in 2011, and is evaluating the option of implementing a cap-and-trade system within the WCI regime. Both provinces are staging their reporting initiatives, starting with easily implemented reports, which gear up to more stringent requirements through the next few years. Suncor currently operates a refinery and petroleum products facility in Ontario and a refinery in Quebec.

U.S. GHG Regulations

Several attempts were made during the course of 2010 to enact GHG legislation in the United States, none of which made it through both the Senate and the House. Given this current void, the President is pressing ahead by endorsing the U.S. Environmental Protection Agency (EPA) to regulate GHG under the Clean Air Act. The implications of industry being regulated under the EPA are as yet unknown. In the meantime, the EPA has implemented a mandatory GHG reporting rule for all large (emitting greater than 25,000 tonnes per year) facilities. This will include Suncor's Commerce City refinery.

The EPA has also mandated Renewable Fuel Standards (2), which encourage ethanol blending up to 15%, from the current 10% limit. Several factors will impact the ability of refiners and producers to achieve these requirements, including the lead time required for fleet turnover, the ability of retail stations to simultaneously provide both 10% and 15% fuels, and the inherent liability for ensuring consumers use the appropriate fuel for their vehicle.

International Regulations

Phase II (2008-2012) of the European Union Emissions Trading Scheme (EU ETS) impacts Suncor's non-operated offshore production in the U.K. and Norway sectors of the North Sea. The EU ETS requires that member countries set emissions limits for installations in their country covered by the scheme and assigns such installations an emissions cap. Installations may meet their cap by reducing emissions or by buying allowances from other participants. Phase III of the EU ETS is scheduled to begin in 2013 and will run until 2020. However, this legislation has not been finalized, particularly in light of the fact that the COP 16 meeting failed to reach an agreement for continuation of the Kyoto Protocol beyond 2012.

RISK FACTORS

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. The following provides a list of risk factors relating to Suncor and our business.

Volatility of Commodity Prices and Exchange Rate Fluctuation

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 OPEC and weather, among other things, can affect world oil supply and demand. Our natural gas price realizations in our Natural Gas segment 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. Given the continued global economic uncertainty, we expect continued volatility and uncertainty in crude oil and natural gas prices in the near term and beyond, with the possibility that crude oil prices could revert to the low levels experienced in 2008 and 2009. 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 natural gas prices and low crude oil prices in particular could have a material adverse effect on our business, financial condition, results of operations and cash flow.

For the year ended December 31, 2010, we conducted an assessment of the carrying value of our assets to the extent required by Canadian GAAP. If crude oil and natural gas prices decline, the carrying value of our assets could be subject to downward revisions, and our earnings could be materially adversely affected.

Our downstream business is sensitive to wholesale and retail margins for its refined products, including, but not limited to, gasoline, diesel, petrochemicals and asphalt. Margin volatility is influenced by, among other things, overall marketplace competitiveness, weather, the cost of crude oil 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, the operating results for our Refining and Marketing business unit can be expected to fluctuate and may be materially adversely affected.

Our 2010 Consolidated Financial Statements are presented in Canadian dollars. Results of operations are affected significantly by the exchange rates between the Canadian dollar and the U.S. dollar, and are also affected by the exchange rates between the Canadian dollar, the euro and the British pound. These exchange rates may vary substantially and 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 operation and cash flow.

Government Regulation

The company, and the oil and gas industry generally, operates under federal, provincial, state and municipal legislation in numerous countries. 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 GHG 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. The following subsections provide more information on some of these regulations.

Environmental Regulation

The company is subject to environmental regulation under a variety of Canadian, U.S., U.K. and other foreign, federal, provincial, territorial, state and municipal laws and regulations. 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;
- The 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 life cycle 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 cleanup costs and damages, and the loss of important licences and permits, which may, in turn, have a material adverse effect on our business, financial condition, results of operations and cash flow.

Climate Change Regulation

While there is a well-defined GHG regulatory system with targets in place for all large industrial facilities in the province of Alberta, no other North American jurisdiction has yet enacted similar strict compliance measures. Suncor anticipates that this current situation will be replaced within the next few years by a series of regional regulatory regimes, or with an all-encompassing federal regime. In general, therefore, 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.

The Canadian federal government has gone on record as saying that it will align GHG emissions legislation with the U.S. Since it remains unclear what approach the U.S. will take, or when, it also is unclear whether the federal government will implement economy-wide climate change legislation, or a sector specific approach, and what type of compliance mechanisms will be available to large emitters.

British Columbia has drafted regulations for a cap-and-trade system, as well as offset regulations, which are intended to be finalized later in 2011. The impact of these regulations cannot be quantified at this time, given the current lack of detail on how the system will operate.

While forthcoming laws and regulations may impose significant liabilities on a failure to comply with their requirements, the cost of meeting new environmental and climate change regulations is not expected to be so high as to cause a material disadvantage, or damage to our competitive positioning. As part of our ongoing business planning, Suncor assesses potential costs associated with carbon dioxide (CO_2) emissions in our evaluation of future projects, based on our current understanding of pending and possible greenhouse gas regulations. Both the U.S. and Canada have indicated that climate change policies that may be implemented will attempt to balance economic, environmental and energy security concerns. We expect that regulation will evolve with a moderate carbon price signal, and that the price regime will progress cautiously. Suncor will continue to review the impact of future carbon constrained scenarios on our strategy, using as a base case price range of $15-$45 per tonne of CO_2 equivalent, applied against a range of regulatory policy options and price sensitivities.

California has passed AB32, which provides for a Low Carbon Fuel Standard (LCFS); although Suncor does not actively market into the state of California, the implications of other states adopting similar LCFS legislation could pose a significant barrier to our exports of oil sands derived crude, if the importing jurisdictions fail to acknowledge the mandated 12% reduction requirement imposed by the company's exporting jurisdiction (Alberta).

While it appears fairly certain that GHG regulations and targets will continue to become more stringent, and while Suncor will continue efforts to reduce the CO_2 unit intensity of our operations, the absolute CO_2 emissions of our company will continue to rise as we pursue a prudent and planned growth strategy.

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. In February 2009, the ERCB released a directive, *Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes*. The directive establishes performance criteria for tailings operations, a requirement for specific approval and monitoring of tailings ponds, a requirement for reporting tailings plans, and changes to the ERCB annual mine plan requirements and approval process to regulate tailings operations.

On October 15, 2009, the company applied to the ERCB and Alberta Environment for permission to amend its existing and/or approved operations east of the Athabasca River to move to the company's new planned TRO_{TM} strategy. In 2010, the company received regulatory approval for a new tailings management plan using the company's proprietary TRO_{TM} tailing management process. It is anticipated that TRO_{TM} will allow the company to accelerate the pace of reclamation and reduce costs in the long term.

At this time, no ponds have been fully reclaimed using this technology. The success of the TRO_{TM} and the time to reclaim tailings ponds could increase or decrease the current asset retirement cost estimates. 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.

Royalties

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

Alberta

The Alberta government enacted new BVM (Ministerial) Regulations as part of the implementation of the New Royalty Framework, effective January 1, 2009. These interim regulations determine the valuation of bitumen for 2009 to 2011. The final regulations are being developed by the Crown that will establish the BVM for future years. For Suncor's mining operations, the BVM is based on the terms of Suncor's RAA, which we believe places certain limitations on the interim BVM as recently enacted. For the years 2009 and 2010, Suncor filed non-compliance notices with the Crown, citing that reasonable adjustments in the determination of the Suncor bitumen value were not considered by the Crown as permitted by Suncor's RAA. Suncor has also filed with the Crown a Notice of Commencement of Arbitration under the Suncor RAA. Syncrude has also filed a non-compliance notice in respect of the determination of the bitumen value under its agreements with the Crown. The final determination of these matters may have a material impact on future royalties payable to the Crown.

The government enacted the new Oil Sands Allowed Costs (Ministerial) Regulations as part of the implementation of the New Royalty Framework, effective January 1, 2009. Further clarification of some allowed cost business rules is still expected. The terms of Suncor's RAA, and the similar agreement entered into by Syncrude, determine the royalty obligation through 2015 for our mining operations. However, potential changes and the interpretation of the allowed cost regulations could, over time, have a significant impact on the amount of royalties payable.

In addition, royalty payments to the Crown could be impacted by 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.

East Coast Canada Royalties

Suncor and the Government of Newfoundland and Labrador are in discussions to resolve several outstanding issues that impact current and prior years. Settlement of these issues could impact royalty payments to the Crown. In addition, royalty payments to the Crown could be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs for each project; changes resulting from regulatory audits of prior year filings; further changes to applicable royalty regimes by the Government of Newfoundland and Labrador; changes in other legislation and the occurrence of unexpected events.

Production Sharing Contracts

Payments pursuant to PSCs could be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs; changes resulting from regulatory audits of prior year filings; further changes to applicable royalty regimes by governments or other applicable regulatory bodies; changes in other legislation and the occurrence of unexpected events all have the potential to have an impact on royalties payable in respect of our international operations in Libya and Syria.

Foreign Operations

The company has operations in a number of countries with different political, economic and social systems. As a result, the company's operations and related assets are subject to a number of risks, which may include, among other things, currency restrictions and exchange rate fluctuations, loss of revenue, property and equipment as a result of expropriation, nationalization, war, insurrection and geopolitical and other political risks, increases in taxes and governmental royalties, renegotiation of contracts with governmental entities and quasi-governmental agencies, changes in laws and policies governing operations of foreign-based companies, economic and legal sanctions (such as restrictions against countries that the U.S. government may deem to sponsor terrorism) and other uncertainties arising from foreign government sovereignty over the company's international operations. If a dispute arises in the company's foreign operations, the company may be subject to the exclusive jurisdiction of foreign courts or may not be able to subject foreign persons to the jurisdiction of a court in Canada or the U.S. Additionally, as a result of activities in these areas and a continuing evolution of an international framework for corporate responsibility and accountability for international crimes, the company could also be exposed to potential claims for alleged breaches of international law.

Operational Hazards and Other Uncertainties

Each of our principal operating businesses – Oil Sands, Natural Gas, International and Offshore, 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, death, damage to property, information technology 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. 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. Risks associated with access to skilled labour to support our operations in a safe and effective manner are also discussed in "Labour and Materials Supply" below.

At Oil Sands, mining oil sands and producing bitumen through in situ methods, extracting bitumen from the oil sands, and upgrading bitumen into SCO and other products involve particular risks and uncertainties. Oil Sands operations are 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, the costs to delineate the resources, the costs associated with production, including mine development and drilling wells for SAGD operations, and the costs associated with upgrading bitumen into SCO can entail significant capital outlays. The costs associated with production at Oil Sands are largely fixed in the short term. As a result, operating costs per unit are largely dependent on levels of production.

There are risks and uncertainties associated with our 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, blowouts, 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 International and Offshore operations include drilling offshore of Newfoundland and Labrador and in the North Sea offshore of the U.K. and Norway, which are areas subject to hurricanes or other extreme weather conditions, and the drilling rigs in these regions may be exposed to damage or total loss by these storms, some of which may not be covered by insurance. The occurrence of these events could result in the suspension of drilling, operations, damage to or destruction of the equipment involved and injury or death of rig personnel. Damage to the environment, particularly through oil spillage in our operations or extensive uncontrolled fires or death, could result from these operations.

Our Refining and Marketing 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 identified above could have a material adverse effect on our business, financial condition, results of operations and cash flow.

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 1990, 2003 and 2005, we formed three self-insurance entities to provide additional business interruption coverage for potential losses. In the first quarter of 2010, these three entities were merged into one single entity.

Project Delivery

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.

Our Oil Sands business 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.

Reputational Risks

The public perception of oil companies and their operations, including GHG emissions related to current and planned projects in the oil sands area of Alberta, may pose issues related to development and operating approvals or market access for products, which may directly or indirectly impair profitability.

Permit Approval

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 numerous factors, including 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.

Labour and Materials Supply

The successful operation of the company's business and ability to expand its operations will depend upon the availability of, and competition for, skilled labour and materials supply. The demand for and supply of skilled labour remains limited, even in uncertain economic conditions, and 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 "Project Delivery" above.

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. Management continues to mitigate the effects of these risks through ongoing succession planning and by monitoring industry conditions.

Labour Relations

Hourly employees at our Oil Sands facilities near Fort McMurray, Alberta, all of our refineries, certain of our lubricants operations, certain of our terminalling operations, our Terra Nova FPSO and at Sun-Canadian Pipeline Company Limited are represented by labour unions or employee associations. Approximately 32% of our unionized employees are members of the Communications Energy and Paperworkers Union (CEP). 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. See "Suncor Employees" in this AIF.

Dependence on Oil Sands Business

Our significant capital commitment to further our growth projects and sustain operations at our Oil Sands business may require us to forego investment opportunities in other segments of our operations. The completion of future projects to increase production at our Oil Sands business will further increase our dependence on the Oil Sands business.

Integration Risk

The company completed the merger with Petro-Canada in order to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits, including cost savings and other operational synergies. Achieving the benefits of the merger depends in part on the ability of Suncor to effectively capitalize on its scale, scope and leadership position in the oil sands industry, to realize the anticipated capital and operating synergies, to profitably sequence the growth prospects of its asset base, to execute planned divestments and to maximize the potential of its improved growth opportunities and capital funding opportunities as a result of combining the businesses and operations of Suncor and Petro-Canada. A variety of factors, including those risk factors set forth in this AIF, may adversely affect the ability to achieve the anticipated benefits of the merger.

The ability to realize the benefits of the merger will also depend in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as on Suncor's ability to realize the anticipated growth opportunities and synergies from integrating Suncor's and Petro-Canada's businesses. This integration is ongoing and requires the dedication of substantial management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the ability of Suncor to achieve the anticipated benefits of the merger.

Uncertainty of Reserves and Resources Estimates

The reserves and contingent resources estimates included in this AIF represent estimates only. There are numerous uncertainties inherent in estimating quantities and quality of these proved and probable reserves and contingent resources, including many factors beyond our control.

In general, estimates of economically recoverable reserves and the future net cash flow from these assets are based upon a number of variable factors and assumptions, such as historical production from the properties, the assumed effect of regulation by governmental agencies, pricing assumptions, the timing and amount of capital expenditures, future royalties, future operating costs and yield rates for production of SCO from bitumen, all of which may vary considerably from actual results. The accuracy of any reserves and resources estimates 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, reserves and resources 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 and MacKay River reserves and resources 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 and resources attributable to any particular group of properties, and classification of such reserves and resources based on risk of recovery, prepared by different engineers or by the same engineers at different times, may vary substantially.

Actual production cash flow is derived from our oil and gas reserves and will vary from the estimates contained in the reserves evaluations, and such variations could be material. The reserves evaluations are 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 reserves evaluations will be reduced to the extent that such activities do not achieve the level of success assumed in the reserves evaluations. The reserves evaluations are effective as of a specific effective date and have not been updated, and thus do not reflect changes in our reserves since that date.

Need to Replace Conventional Reserves

Future conventional oil and natural gas reserves and production from our International and Offshore and Natural Gas business units are highly dependent on our successful discovery or acquisition of additional reserves and exploitation of our current reserves base. Without conventional oil and natural gas reserves additions through exploration and development or acquisitions, our conventional oil and natural gas reserves and production will decline over time as reserves are depleted. 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 the company 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 oil and natural gas reserves could be impaired. In addition, the long-term performance of the conventional oil and 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. There can be no assurance that we will be able to find and develop or acquire additional reserves to replace production at acceptable costs.

In Situ Recovery

Current 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 the steam 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 SAGD 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.

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.

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 other circumstances 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, even with appropriate risk management, 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.

Control Environment

Based on their evaluation as of December 31, 2010, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States *Securities Exchange Act of 1934* (the Exchange Act)) are effective to ensure that information required to be disclosed by us in reports that we file or submit to Canadian and U.S. securities authorities is recorded, processed, summarized and reported within the time periods specified in Canadian and U.S. securities laws. In addition, as of December 31, 2010, there were no changes in our internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) to 15d-15(f)) that occurred during the year ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We will continue to periodically evaluate our disclosure controls and procedures and internal control over financial reporting and will make any modifications from time-to-time as deemed necessary.

Based on their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

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 and floating rate bank facilities and commercial paper, with the remainder issued in fixed rate borrowings, which could increase the company's cost of capital and impact Suncor's financial performance. To manage such 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.

Capital Markets

Future capital expenditures will be financed out of cash generated from operations and borrowings. This ability 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.

The market events and conditions witnessed over the past several years, including disruptions in international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility in commodity prices and increases in the rates at which we are able to borrow funds for our capital programs. There can be no certainty regarding the timing or extent of the recent economic recovery, and such continued uncertainty in the global economic situation means that the company, along with all other oil and gas entities, may continue to face restricted access to capital and increased borrowing costs. This could have an adverse effect on the company, as our future capital expenditures will be financed out of cash generated from operations and borrowings, and our ability to borrow 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, 2010, we had approximately $5.3 billion of unused credit available under bank credit facilities. Based on current funds available and expected cash from operations and our divestures that we have announced but that had not yet closed as of December 31, 2010, we believe that we have sufficient funds available to fund our currently projected capital expenditures in 2011. If cash flow from operations is lower than expected or 2011 capital expenditures exceed current estimates, or if we incur major unanticipated expenses related to development or maintenance of our existing assets, we would need to undertake a serious evaluation of maintaining our capital program at planned levels and the possibility of adversely affecting our debt ratings should we seek additional capital. Choosing not to obtain the financing necessary for our capital expenditure plans may result in a delay in the planned development of production from our operations and strand significant capital, while increasing costs to keep projects in safe mode. 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, including higher interest rates and fees. Neither the company's articles nor its bylaws limit the amount of indebtedness that we may incur; however, we are subject to covenants in our existing bank facilities and seek to avoid onerous costs of debt. 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 affect 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 $8.0 billion in credit facilities expiring primarily in 2013, and approximately $12.2 billion in outstanding debt. We are required to comply with financial and operating covenants under these credit facilities and debt securities. 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 and debt securities, 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 favourable terms, if at all, and any restrictions imposed on our borrowings under these facilities due to our covenants, could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Hedging

The company monitors its exposure to variations in commodity prices, interest rates and foreign exchange rates. In response, the company periodically enters into physical delivery transactions for commodities at fixed or collared prices and into derivative financial instruments to reduce exposure to unfavourable movements in commodity prices, interest rates and foreign exchange rates. The terms of these contracts or instruments may limit the benefit of favourable changes in commodity prices, interest rates and currency values and may result in financial or opportunity loss due to delivery commitments, royalty rates and counterparty risks associated with the contracts.

Competition

The petroleum industry is highly competitive globally 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 petrochemicals. 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 major international oil and natural gas producers.

A number of other companies have entered or have indicated their intention to enter the oil sands business and begin producing bitumen and SCO or expand their existing operations. 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. 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 SCO and other competing crude oil products in the marketplace;

(b) Exponentially 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.

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.

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.

Counterparties Exposure

In the normal course of business, the company enters into contractual relationships with counterparties in the energy industry and other industries, including counterparties to interest rate hedging, foreign exchange hedging and commodity derivative arrangements. If such counterparties do not fulfil their contractual obligations to the company, it may suffer losses, may have to proceed on a sole risk basis, may have to forego opportunities or may have to relinquish leases or blocks. While the company limits its exposure to any one counterparty to a level that management deems to be reasonable, losses due to counterparties failing to fulfil their contractual obligations may have a material adverse effect on our business, financial condition, results of operations and cash flow.

Suncor's Governance Process

Suncor believes that the responsibility for managing climate change related issues should be a shared responsibility across the company. A comprehensive roles and responsibilities matrix has been developed as part of Suncor's GHG management program.

The Environment, Health, Safety and Sustainable Development Committee of the Board of Directors reviews Suncor's effectiveness in meeting its obligations pertaining to environment, health and safety (EHS). The committee also reviews the effectiveness with which Suncor establishes appropriate environment, health and safety policies, including GHG performance and emission reduction plans given legal, industry and community standards. Management systems are maintained by the committee to implement such policies and ensure compliance with them.

Suncor's Chief Operating Officer holds top executive responsibility for sustainability issues. Together with the Vice President, Sustainable Development, the business units' EHS managers and selected internal technical representatives are responsible for the stewardship of the GHG management system. The GHG strategy team is responsible for developing company-wide strategies and operational goals and assessing sustainability progress, including GHG intensity reduction, across all areas of our business.

In advance of clear regulations in all jurisdictions that we operate, Suncor will continue to be guided by the seven-point climate change action plan we first adopted in 1997, which calls on us to:

- Manage our own GHG emissions;
- Develop renewable sources of energy;
- Invest in environmental and economic research through joint venture initiatives with other industry groups, and through internal initiatives focused on our core business;
- Use domestic and international offsets;
- Collaborate on policy development;
- Educate employees and the public; and
- Measure and report our progress;

Suncor remains committed to reducing overall GHG emission intensity, in addition to other goals related to improving energy efficiency, reducing water use, increasing land reclamation, and reducing air emissions. We continue to actively work to mitigate our environmental impact, including taking action to reduce GHG emissions, investing in renewable forms of energy such as wind power and biofuels, accelerating land reclamation, installing new emissions abatement equipment and pursuing other opportunities both internally, as well as through joint venture initiatives, such as our role in the Oil Sands Leadership Initiative, with other like-minded energy companies.

DIVIDENDS

Our Board of Directors has established a policy of paying dividends on a quarterly basis. We review our dividend policy from time-to-time with regard to our financial position, financing requirements for growth, cash flow and other factors which our Board of Directors considers relevant. Our Board of Directors approved an increase in the quarterly dividend to $0.10 per share from $0.05 per share in the third quarter of 2009. Dividends are paid subject to applicable law, if, as and when declared by the Board of Directors.

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

	Year Ended December 31		
	2010	2009	2008 (1)
Cash dividends per common share	$ 0.40	$ 0.30	$ 0.20

(1) 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

The company's authorized share capital is comprised of an unlimited number of common shares, an unlimited number of preferred shares issuable in series designated as senior preferred shares and an unlimited number of preferred shares issuable in series designated as junior preferred shares. As at December 31, 2010, there were 1,565,489,162 common shares issued and outstanding. To the knowledge of the Board of Directors and executive officers of Suncor, no person beneficially owns or exercises control or direction over securities carrying 10% or more of the voting rights attached to any class of voting securities of the company. The holders of common shares are entitled to attend all meetings of shareholders and vote at any such meeting on the basis of one vote for each common share held. As no senior preferred shares or junior preferred shares are issued and outstanding, common shareholders are entitled to receive any dividend declared by the Board of Directors on the common shares and to participate in a distribution of the company's assets among its shareholders for the purpose of winding up its affairs. The holders of the common shares shall be entitled to share equally, share for share, in all distributions of such assets.

Constraints

The *Petro-Canada Public Participation Act* requires that the Articles of Suncor include certain restrictions on the ownership and voting of voting shares of the company. The common shares of Suncor are voting shares.

No person, together with associates of that person, may subscribe for, have transferred to that person, hold, beneficially own or control otherwise than by way of security only, or vote in the aggregate, voting shares of Suncor to which are attached more than 20% of the votes attached to all outstanding voting shares of Suncor. Additional restrictions include provisions for suspension of voting rights, forfeiture of dividends, prohibitions against share transfer, compulsory sale of shares, and redemption and suspension of other shareholder rights. The Board of Directors may at any time require holders of, or subscribers for, voting shares, and certain other persons, to furnish statutory declarations as to ownership of voting shares and certain other matters relevant to the enforcement of the restrictions. Suncor is prohibited from accepting any subscription for, and issuing or registering a transfer of, any voting shares if a contravention of the individual ownership restrictions results.

Suncor's Articles, as required by the *Petro-Canada Public Participation Act*, also include provisions requiring Suncor to maintain its head office in Calgary, Alberta; prohibiting Suncor from selling, transferring or otherwise disposing of all or substantially all of its assets in one transaction, or several related transactions, to any one person or group of associated persons, or to non-residents, other than by way of security only in connection with the financing of Suncor; and requiring Suncor to ensure (and to adopt, from time-to-time, policies describing the manner in which Suncor will fulfil the requirement to ensure) that any member of the public can, in either official language of Canada (English and French), communicate with and obtain available services from Suncor's head office and any other facilities where Suncor determines there is significant demand for communication with, and services from, that facility in that language.

Ratings

The following information regarding the company's credit ratings is provided as it relates to the company's cost of funds and liquidity and indicates whether or not the company's credit ratings have changed. In particular, the company's ability to access unsecured funding markets and to engage in certain collateralized business activities on a cost-effective basis is primarily dependent upon maintaining competitive credit ratings. A lowering of the company's credit rating may also have potentially adverse consequences for the company's funding capacity or access to the capital markets, may affect the company's ability, and the cost, to enter into normal course derivative or hedging transactions and may require the company to post additional collateral under certain contracts.

The following table shows the ratings issued by the rating agencies noted therein as of December 31, 2010. The credit ratings are not recommendations to purchase, hold or sell the debt securities 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.

	Moody's Investors Service (Moody's)	Standard & Poor's (S&P)	Dominion Bond Rating Service (DBRS)
Outlook	Stable	Stable	Stable
Senior Unsecured	Baa2	BBB+	A (low)
Commercial Paper	—	A-1 (Low)	R-1 (low)

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 10 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 are considered to 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 or D categories.

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 Baa2 by Moody's is the fourth highest of nine categories. Obligations rated Baa are subject to moderate credit risk. They are considered medium-grade and, as such, may possess certain speculative characteristics. Moody's appends numerical modifiers 1, 2 or 3 to each generic rating classification. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

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 10 categories and indicates that the obligor exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. 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 represents the range from highest to lowest quality of such securities rated. A rating of R-1 (low) by DBRS is the third highest of 10 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.

S&P's commercial paper credit ratings are on a short-term debt rating scale that ranges from A-1 (High) to D, which represents the range from highest to lowest quality of such securities rated. A short-term obligation rated A-1 is rated as the highest of eight categories by Standard & Poor's. A short-term obligation rated "A-1 (Low)" is slightly more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rating categories. However, the obligor's capacity to meet its financial commitment on the obligation is satisfactory. Obligations rated "A-1 (Low)" on the Canadian commercial paper rating scale would qualify for a rating of "A-2" on Standard & Poor's global short-term rating scale.

MARKET FOR SECURITIES

Price Range and Trading Volume of Common Shares

Our common shares are listed on the Toronto Stock Exchange (TSX) in Canada, and on the New York Stock Exchange (NYSE) in the United States. The price ranges and the volumes traded on the TSX and NYSE for the year ended December 31, 2010, are as follows:

Toronto Stock Exchange

	Price Range ($Cdn)		Trading Volume
	High	Low	(000's)
2010			
January	39.45	33.56	67,463
February	34.86	29.93	115,117
March	33.35	30.36	110,834
April	35.82	32.81	104,327
May	35.59	29.91	121,481
June	35.31	31.28	108,655
July	34.04	30.72	69,069
August	34.94	31.08	73,844
September	34.47	31.80	94,774
October	35.48	32.25	80,396
November	36.55	32.66	90,386
December	38.56	34.87	70,631

New York Stock Exchange

	Price Range ($Cdn)		Trading Volume
	High	Low	(000's)
2010			
January	38.22	31.38	108,347
February	32.81	28.04	221,741
March	32.85	29.01	173,839
April	35.71	32.21	175,022
May	34.90	27.65	237,363
June	34.77	29.38	169,804
July	33.16	28.56	105,033
August	34.17	29.15	93,279
September	33.50	30.72	103,742
October	35.40	31.53	130,354
November	36.60	32.20	137,647
December	38.49	34.18	106,369

Options to Purchase Common Shares

For information in respect of options to purchase common shares of Suncor, see note 20 of our 2010 Consolidated Financial Statements, which is incorporated by reference into this AIF.

DIRECTORS AND EXECUTIVE OFFICERS

Directors

The following individuals are directors of Suncor. The term of each director is from the date of the meeting at which he or she is elected or appointed until the next annual meeting of shareholders or until a successor is elected or appointed.

Name and Jurisdiction of Residence	Period Served and Independence	Biography
Mel E. Benson (1)(2) 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 an owner of Tenax Energy Inc., a director of Winalta Inc. and director of the Fort McKay Group of Companies, a community trust. 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 (2)(3) Washington, USA	Director since 1995 Independent	Brian Canfield is the chairman of TELUS Corporation, a telecommunications company. Beginning his career with TELUS as a telephone installer in 1956, Mr. Canfield rose through the corporate ranks to occupy positions as COO, President and CEO. 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. He was also the first businessperson to receive an honorary Doctorate of Technology from the BC Institute of Technology.
Dominic D'Alessandro (3)(4) Ontario, Canada	Director since 2009 Independent	Dominic D'Alessandro was president and chief executive officer of Manulife Financial Corporation from 1994 to 2009 and is currently a director of CGI Group Inc. and Canadian Imperial Bank of Commerce. For his many business accomplishments, Mr. D'Alessandro was recognized as Canada's Most Respected CEO in 2004 and CEO of the Year in 2002, and was inducted into the Insurance Hall of Fame in 2008. Mr. D'Alessandro is an officer of the Order of Canada and has been appointed as a Commendatore of the Order of the Star of Italy. In 2009, he received the Woodrow Wilson Award for Corporate Citizenship and in 2005 was granted the Horatio Alger Award for community leadership. Mr. D'Alessandro is an FCA, and holds a Bachelor of Science from Concordia University in Montreal. He has also been awarded honorary doctorates from York University, the University of Ottawa, Ryerson University and Concordia University.
John T. Ferguson (5) 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 board member of the Alberta Bone and Joint Institute, an advisory member of the Canadian Institute for Advanced Research, Honorary Lieutenant Colonel – South Alberta Light Horse and chancellor emeritus and chairman emeritus of the University of Alberta. Mr. Ferguson is a fellow of the Alberta Institute of Chartered Accountants and of the Institute of Corporate Directors.
W. Douglas Ford (1)(4) 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 director of the Home Run Inn and 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. 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.

Name and Jurisdiction of Residence	Period Served and Independence	Biography
Paul Haseldonckx (2)(3) Essen, Germany	Director since 2009 (Petro-Canada 2002 to July 31, 2009) Independent	Paul Haseldonckx was a director of Petro Canada and a member of the management board of Veba Oel AG, Germany's largest downstream company, including Aral AG gas stations in Europe. Mr. Haseldonckx represented Veba's interests at the board of the Cerro Negro joint venture, an in situ oil sands development including an upgrader, during the construction and early production phase. Mr. Haseldonckx holds a Master of Science and completed Executive Programs at INSEAD, Fontainebleau and IMD, Lausanne.
John R. Huff (1)(2) Texas, USA	Director since 1998 Independent	John Huff is chairman of Oceaneering International Inc., an oilfield services company. He also serves as director of KBR Inc.
Jacques Lamarre (1)(2) Quebec, Canada	Director since 2009 Independent	Jacques Lamarre was the president and chief executive officer of SNC Lavalin from 1996-2009. Mr. Lamarre is an officer of the Order of Canada, and a founding member and past chair of the Commonwealth Business Council. He is also past chair of the Board of Directors of the Conference Board of Canada and a founding member of the World Economic Forum's Governors for Engineering & Construction. Currently, he serves as a director of The Royal Bank of Canada and of P3 Canada and as a member of the Engineering Institute of Canada, Engineers Canada and the Ordre des ingénieurs du Québec. Mr. Lamarre is also a strategic advisor to Heenan Blaikie LLP, a law firm. Mr. Lamarre holds a Bachelor of Arts and a Bachelor of Arts and Science in Civil Engineering from Laval University in Quebec City. He also completed Harvard University's Executive Development Program. In addition, Mr. Lamarre holds honorary doctorates from the University of Waterloo, the University of Moncton and Laval University.
Brian MacNeill (3)(4) Alberta, Canada	Director since 2009 (Petro-Canada 1995 to July 31, 2009) Independent	Brian MacNeill is a Chartered Accountant, a Certified Public Accountant and holds a Bachelor of Commerce. Previously, Mr. MacNeill was a director and chairman of the board of Petro Canada. He is a director of TELUS Corporation, West Fraser Timber Co. Ltd., Capital Power Corp. and Oilsands Quest Inc. Mr. MacNeill is a member of the Canadian Institute of Chartered Accountants and the Financial Executives Institute. He is also a fellow of the Alberta Institute of Chartered Accountants and of the Institute of Corporate Directors. Mr. MacNeill is also a member of the Order of Canada.
Maureen McCaw (1)(2) Alberta, Canada	Director since 2009 (Petro-Canada 2004 to July 31, 2009) Independent	Maureen McCaw was a director of Petro-Canada and is senior vice president (Edmonton) of Leger Marketing, formerly Criterion Research Corp., a company she founded in 1986. Ms. McCaw holds a Bachelor of Arts from the University of Alberta and an Institute of Corporate Directors certification (ICD.D). In addition to being president of Tinnakilly Inc. and a director of the Edmonton International Airport, Women Building Futures and Royal Alexandria Hospital, she is also managing partner at Prism Ventures. She is a past chair of the Edmonton Chamber of Commerce and serves on a number of Alberta boards and advisory committees.
Michael W. O'Brien (3)(4) 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 is lead director of Shaw Communications Inc. 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.
James Simpson (1)(4) Alberta, Canada	Director since 2009 (Petro-Canada 2004 to July 31, 2009) Independent	James Simpson was a director of Petro-Canada and is past president of Chevron Canada Resources (oil and gas). He serves as Lead Director for Canadian Utilities Limited and is on its Corporate Governance, Nomination, Compensation and Succession Committee and Risk Review Committee, as well as being the chairman for the Audit Committee. Mr. Simpson holds a Bachelor of Science and Master of Science, and graduated from the Program for Senior Executives at M.I.T.'s Sloan School of Business. He is also past chairman of the Canadian Association of Petroleum Producers and past vice chairman of the Canadian Association of the World Petroleum Congresses.

Name and Jurisdiction of Residence	Period Served and Independence	Biography
Eira M. Thomas[(3)(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., Fortress Minerals Corp., Ashton Mining of Canada Inc. and Lucara Diamond 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) Human Resources and Compensation Committee.
(2) Environment, Health, Safety and Sustainable Development Committee.
(3) Audit Committee.
(4) Governance Committee.
(5) As chairman, by standing invitation, Mr. Ferguson is considered an ex-officio member of all committees.

Executive Officers

The following individuals are the executive officers of Suncor.

Name and Jurisdiction of Residence	Office
Richard L. George Alberta, Canada	President and Chief Executive Officer
Steve W. Williams Alberta, Canada	Chief Operating Officer
Bart Demosky Alberta, Canada	Chief Financial Officer
Kirk Bailey Alberta, Canada	Executive Vice President, Oil Sands Ventures
Boris Jackman Ontario, Canada	Executive Vice President, Refining and Marketing
Mark Little Alberta, Canada	Executive Vice President, Oil Sands
Kevin D. Nabholz Alberta, Canada	Executive Vice President, Major Projects
Jay Thornton Alberta, Canada	Executive Vice President, Energy Supply, Trading and Development
Eric Axford Alberta, Canada	Senior Vice President, Operations Support
Francois Langlois Alberta, Canada	Senior Vice President, Exploration and Production
Sue Lee Alberta, Canada	Senior Vice President, Human Resources and Communications
Mike MacSween Alberta, Canada	Senior Vice President, In Situ
Janice Odegaard Alberta, Canada	Senior Vice President, General Counsel and Corporate Secretary
Andrew Stephens Alberta, Canada	Senior Vice President, Business Services

As at December 31, 2010, the directors and executive officers of Suncor as a group beneficially owned, or controlled or directed, directly or indirectly, common shares of Suncor representing less than 1% of the then outstanding common shares.

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 company or has owned a personal holding company 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 that was in effect for a period of more than 30 consecutive days; or

  (ii) was subject to a cease trade order or an order similar to a cease trade order, or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days, after the director or executive officer ceased to be a director or executive officer in the company and which resulted from an event that occurred while that person was acting in the capacity as a director or executive officer; 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 nor any holding company controlled by such person 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 of Suncor, or any subsidiary of Suncor, has any existing or potential direct or indirect material conflicts of 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 business units and corporate office for the past two years.

	As at December 31,	
	2010	2009
Oil Sands	4 753	4 616
Natural Gas	382	786
International and Offshore	516	582
Refining and Marketing	3 151	3 347
Corporate (1)	3 274	3 647
Total (2)	12 076	12 978

(1) Corporate employees include employees from our Major Projects group, which supports our business units, and employees from our Energy Supply, Trading and Development group.

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

Approximately 38% of the company's employees were covered by collective bargaining agreements in 2010.

The Communications, Energy and Paperworkers Union (CEP) represents the majority of the company's unionized employees. A new collective agreement with CEP Local 707, representing approximately 3,000 Oil Sands employees was entered into effective September 17, 2010. The terms of the three-year agreement include a wage increase of 2.5% in 2010, 4% in 2011 and 4% in 2012, and an initial lump sum payment of $1,500 per employee. The collective agreement with Local 707 will expire May 1, 2013.

Approximately 900 additional employees in the company's refinery, lubricants, natural gas, terminals, in situ and offshore production operations are also represented by the CEP. Three-year collective bargaining agreements with the CEP locals representing those employees were renewed in 2010 with wage increases of 2.5% in 2010, 3% in 2011 and 3.25% in 2012.

An independent union, the Suncor Employee Bargaining Association, represents approximately 220 employees at the Sarnia refinery. The agreement at the Sarnia refinery expires in May 2012.

The United Steel Workers Union (USW) represents approximately 240 employees at the Commerce City refinery. The USW collective agreement will expire in January 2012.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate

The Audit Committee Mandate is attached as Schedule "A" to this AIF.

Composition of the Audit Committee

The Audit Committee is comprised of Mr. Canfield (Chairman), Mr. D'Alessandro, Mr. MacNeill, Mr. O'Brien, Mr. Haseldonckx 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 experts on the Audit Committee are Michael W. O'Brien and Dominic D'Alessandro.

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* and applicable Canadian law, is attached as Schedule "B" to this AIF.

Fees Paid to Auditors

Fees payable to PricewaterhouseCoopers LLP in 2010 and 2009 are detailed below:

($)	2010	2009
Audit Fees	4 873 000	4,307 000
Audit-Related Fees	637 000	807 000
All Other Fees	4 000	164 000
Total	5 514 000	5 278 000

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.

All Other Fees

Fees disclosed under "All Other Fees" were paid-for subscriptions to auditor-provided and supported tools as well as externally sourced, direct or indirect, internal audit services in legacy Petro-Canada businesses.

The services described under the captions "Audit-Related Fees" and "All Other Fees" were approved by the Audit Committee pursuant to paragraph (c)(7)(i) of Rule 2-01 of Regulation S-X.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings to which we are or were a party, or of which any of our property is or was the subject since the beginning of the company's most recently completed financial year, nor are there any proceedings known by us to be contemplated that involve 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 our 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 the financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer, or any person or company that beneficially owns or controls or directs, directly or indirectly, more than 10% of our securities or any associate or affiliate of these persons has, or has had, any material interests in any transaction or any proposed transaction that has materially affected or is reasonably expected to 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, 2010, we have not entered into any contracts, nor are there any contracts still in effect, that are material to our business, other than contracts entered into in the ordinary course of business, and that are not required to be filed by Section 12.2 of National Instrument 51-102.

INTERESTS OF EXPERTS

Reserves and resources estimates contained in this AIF are based in part upon reports prepared by GLJ and Sproule, Suncor's Independent Reserve Engineering Evaluators. The 2010 Consolidated Financial Statements of the Company have been audited by PricewaterhouseCoopers LLP, Suncor's auditors. As at the date hereof, none of the partners, employees or consultants of GLJ or Sproule, respectively, as a group, through registered or beneficial interests, directly or indirectly, held or are entitled to receive more than 1% of any class of our outstanding securities, 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 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, 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 herein, 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 2010 Consolidated Financial Statements for our most recently completed financial year and the MD&A.

Further information about Suncor, filed with Canadian securities commissions and the SEC, including periodic quarterly and annual reports and the AIF/40-F is available online on SEDAR at www.sedar.com and on EDGAR at 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"

AUDIT COMMITTEE MANDATE

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, including 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 Audit Committee has the following functions and responsibilities:

Internal Controls

1. Inquire 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 Standards of Business Conduct Code.
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 overseeing 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 Head of Internal Audit, annually review a summary of the remuneration of the Head of Internal Audit, and periodically review the performance and effectiveness of the Internal Audit function including compliance with The Institute of Internal Auditors' International Professional Practices Framework for Internal Auditing.
12. Review the Internal Audit Department Charter, and the plans, activities, organizational structure and qualifications of the Internal Auditors, and monitor the department's 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 the external auditor's management comment letter and management's responses thereto, and inquire 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 thereof.
15. Review with management and the 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. Authorize any changes to the categories of documents and information requiring audit committee review or approval prior to external disclosure, as set out in the Corporation's policy on external communication and disclosure of material information.
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 Evaluators, including the qualifications and independence of the Evaluators; review and approve any proposed change in the appointment of the Evaluators, and the reasons for such proposed change including whether there have been disputes between the Evaluators and management.
22. Annually review Suncor's reserves data and the report of the Evaluators 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 the report thereon of management and the directors to be included in or filed with the Statement, and (ii) the filing of the report of the Evaluators 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.
28. Review and/or approve other financial matters delegated specifically to it by the Board of Directors.

Reporting to the Board

29. Report to the Board of Directors on the activities of the Audit 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.

Approved by resolution of the Board of Directors on November 9, 2010.[1]

(1) Previously revised on August 1, 2009

SCHEDULE "B"

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 "C"

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

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

1. We have evaluated the company's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, 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, 2010, 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 – $MM)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	Oil Sands In Situ January 11, 2011	Canada	—	18,477	—	18,477
GLJ Petroleum Consultants	Oil Sands Mining January 11, 2011	Canada	—	29,165	—	29,165
						47,642

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, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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 judgements regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 3, 2011

"Dana B. Laustsen"

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

SCHEDULE "D"

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

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

1. We have evaluated and reviewed the company's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, 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 and review.

   We carried out our evaluation and review 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 and review to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation and review 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 and reviewed by us as of December 31, 2010, and identifies the respective portions thereof that we have evaluated and reviewed and reported on to the company's management and board of directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $MM)			
Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	Conventional Offshore (East Coast Canada) February 18, 2011	Canada	—	6,399	—	6,399
Sproule Associates Limited	Conventional Onshore (Natural Gas) February 18, 2011	Canada	—	2,761	—	2,761
Sproule International Limited	North Sea February 18, 2011	North Sea, United Kingdom	—	8,014	1,094	9,108
Sproule International Limited	Other International February 18, 2011	Libya, Syria	—	5,590	—	5,590
			—	22,764	1,094	23,858

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

EXECUTED as to our report referred to above:

Sproule Associates Limited and Sproule International Limited, Calgary, Alberta, Canada, March 3, 2011

"R. Keith MacLeod"

R. Keith MacLeod, P.Eng.
President and Director

SCHEDULE "E"

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

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, 2010, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated and reviewed the Company's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Audit Committee of the Board of Directors of the Company has:

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

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

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

The Audit Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas 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 evaluators on the reserves data; and

(c) the content and filing of this report.

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

"*Richard L. George*"
RICHARD L. GEORGE
President and Chief Executive Officer

"*Bart Demosky*"
BART DEMOSKY
Chief Financial Officer

"*John T. Ferguson*"
JOHN T. FERGUSON
Chairman of the Board of Directors

"*Brian A. Canfield*"
BRIAN A. CANFIELD
Chairman of the Audit Committee

March 3, 2011

SUNCOR
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