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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(Check One)

o Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934

or

ý Annual report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934

For fiscal year ended: December 31, 2011
Commission File Number: No. 1-12384

SUNCOR ENERGY INC.
(Exact name of registrant as specified in its charter)

Canada	**1311,1321,2911, 4613,5171,5172**	**98-0343201**
(Province or other jurisdiction of incorporation or organization)	(Primary standard industrial classification code number, if applicable)	(I.R.S. employer identification number, if applicable)

150 - 6th Avenue S.W.
Box 2844
Calgary, Alberta, Canada T2P 3E3
(403) 296-8000

(Address and telephone number of registrant's principal executive office)

CT Corporation System
111 Eighth Avenue
New York, New York, U.S.A. 10011
(212) 894-8940

(Name, address and telephone number of agent for service in the United States)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class:	Name of each exchange on which registered:
Common shares	**New York Stock Exchange**

Securities registered or to be registered pursuant to Section 12(g) of the Act:

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

None

For annual reports, indicate by check mark the information filed with this form:

ý Annual Information Form ý Annual Audited Financial Statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

Common Shares	**As of December 31, 2011 there were 1,558,636,368 Common Shares issued and outstanding**
Preferred Shares, Series A	**None**

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the proceeding 12 months (or for such shorter period that the registrant was required to file such reports); and (2) has been subject to such filing requirements in the past 90 days.

Yes ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes o No o

ANNUAL INFORMATION FORM DATED MARCH 1, 2012



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ADVISORIES

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. On August 1, 2009, Suncor completed its merger with Petro-Canada, referred to in this document as the "merger". References to the "Board of Directors" or the "Board" mean the Board of Directors of Suncor Energy Inc., unless the context otherwise requires.

All financial information is reported in Canadian dollars, unless otherwise noted. Production volumes are presented on a working-interest basis, before royalties, unless otherwise noted. Certain amounts in prior years may have been reclassified to conform to the current year's presentation.

References to our 2011 audited Consolidated Financial Statements mean Suncor's audited Consolidated Financial Statements prepared in accordance with Canadian generally accepted accounting principles (GAAP), the notes and the auditors' report, as at and for each year in the two-year period ended December 31, 2011. References to our MD&A mean Suncor's Management's Discussion and Analysis, dated February 23, 2012.

Unless otherwise noted, all financial information has been prepared in accordance with Canadian GAAP, which is within the framework of International Financial Reporting Standards (IFRS).

This AIF contains forward-looking information based on Suncor's current expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, including those discussed in this document in the Risk Factors section, many of which are beyond the company's control. Users of this information are cautioned that actual results may differ materially. Refer to the Advisory – Forward-Looking Information section of this AIF for information on other risk factors and the material assumptions underlying our forward-looking information.

Information contained in or otherwise accessible through Suncor's website www.suncor.com does not form a part of this AIF, and is not incorporated into the AIF by reference.

GLOSSARY OF TERMS AND ABBREVIATIONS

Common Industry Terms

Products

Hydrocarbons are solids, liquids or gas made up of compounds of carbon and hydrogen, in varying proportions.

Crude oil is a mixture of pentanes (lighter hydrocarbons) and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained in the processing of natural gas.

> **Bitumen or heavy crude oil** is a naturally occurring viscous mixture, consisting mainly of pentanes and heavier hydrocarbons, which may not be recoverable at a commercial rate in its naturally occurring viscous state through a well without using enhanced recovery methods. After it is extracted, bitumen or heavy crude oil may be upgraded into crude oil and other petroleum products.
>
> **Conventional crude oil** is crude oil produced through wells by standard industry recovery methods.
>
> **Oil sands** are naturally occurring deposits of sand or sandstone, or other sedimentary rocks that contain bitumen.
>
> **Synthetic crude oil** (SCO) is a mixture of hydrocarbons derived by upgrading bitumen from oil sands. SCO 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 synthetic crude oil**, while SCO with higher sulphur content is referred to as **sour synthetic crude oil**.
>
> **West Texas Intermediate** is a type of crude oil used as a benchmark in oil pricing, and is the underlying commodity of futures contracts on the New York Mercantile Exchange (NYMEX).

Natural gas is a mixture of lighter hydrocarbons, which at atmospheric conditions of temperature and pressure is in a gaseous state.

> **Conventional natural gas** is natural gas produced from all geological strata, including associated, non-associated and solution gas, but excluding coal bed methane and shale gas.
>
> **Non-associated gas** is an accumulation of natural gas in a reservoir where there is no crude oil. **Associated gas** is the gas cap overlying a crude oil accumulation in a reservoir.

Solution gas is natural gas dissolved in crude oil in a reservoir.

Natural gas liquids (NGLs) are 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.

Oil and gas exploration and development processes

Development costs are costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves.

Exploration costs are costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves.

Field is a defined geographical area consisting of one or more pools containing hydrocarbons.

Glory hole is an excavation into the sea floor designed to protect wellhead equipment from icebergs, and which typically contains multiple wellheads.

Reservoir is 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.

Wells:

Development wells are 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.

Dry wells are exploratory or development wells found to be incapable of producing either oil or gas in sufficient quantities to justify the completion as an oil or gas well.

Exploratory wells are drilled in a territory without existing proved reserves, with the intention to discover commercial reservoirs or deposits of crude oil and/or natural gas. Exploratory wells include **appraisal wells**, which are drilled to measure the commercial potential (i.e. size and quality) of a hydrocarbon discovery. Before development, an offshore discovery is likely to need several appraisal wells.

Service wells are drilled or completed for the purpose of supporting production in an existing field, such as wells drilled for observation or wells drilled for the injection of gas or water.

Stratigraphic wells are drilling efforts, geologically directed, to obtain information pertaining to a specific geologic condition, such as **core hole drilling** on oil sands leases, and are usually drilled without the intention of being completed for production.

Production processes

Capacity is the annual average output that may be achieved from a processing facility, such as an upgrader, refinery or natural gas processing plant, under ideal operating conditions and in accordance with current design specifications.

Downstream refers to the refining of crude oil or synthetic crude oil and the selling and distribution of refined products in retail and wholesale channels.

Feedstock generally refers either to i) the bitumen required in the production of synthetic crude oil for the company's oil sands operations; or ii) crude oil and/or other components required in the production of refined products for the company's downstream operations.

In situ or "in place" refers to methods of extracting bitumen or heavy crude oil from deep deposits of oil sands by means other than surface mining.

Overburden is the material overlying oil sands that must be removed before mining, which consists of muskeg, glacial deposits and sand.

Production Sharing Contracts (PSC) are a common type of contract signed between a government and a resource extraction company that states how much of the resource produced each party will receive and which parties are responsible for the development and operation of the resource. An **Exploration and Production Sharing Agreement (EPSA)** is a form of Production Sharing Contract, which also states which parties are responsible for exploration activities.

Steam-assisted gravity drainage (SAGD) is 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, from which it is pumped out.

Steam-to-oil ratio (SOR) is a metric used to quantify the efficiency of an in situ oil recovery process, which measures the cubic metres of steam required to produce one cubic metre of oil. The lower the ratio, the higher the efficiency of the use of steam.

Utilization is the average use of capacity, and includes the impact of planned and unplanned facility outages and maintenance. More specifically, **refinery utilization** is the amount of crude oil and natural gas plant liquids run through crude distillation units, expressed as a percentage of the capacity of these units.

Upgrading is the two-stage process by which bitumen or heavy crude oil is converted into synthetic crude oil.

> **Primary upgrading,** also referred to as coking or thermal cracking, heats the bitumen in coke drums to remove excess carbon. The superheated hydrocarbon vapours are sent to fractionators where they condense into naphtha, kerosene and gas oil. Carbon residue, or coke, is removed from the coke drums on short intervals and later sold as a byproduct.
>
> **Secondary upgrading,** a purification process also referred to as hydrotreating, adds hydrogen to, and reduces the sulphur of, primary upgrading output to create sweet synthetic crude oil and diesel.

Upstream refers to the exploration, development and production of conventional crude oil, bitumen or natural gas.

Reserves and resources

Please refer to the Definitions for Reserves Data Tables section of the Statement of Reserves Data and Other Oil and Gas Information in this AIF.

Common Abbreviations

The following is a list of abbreviations that may be used in this AIF:

Measurement

bbl(s)	barrel(s)
bbls/d	barrels per day
mbbls/d	thousands of barrels per day
mmbbls	millions of barrels
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mmboe	millions of barrels of oil equivalent
mcf	thousands of cubic feet of natural gas
mcf/d	thousands of cubic feet of natural gas per day
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
mmcf/d	millions of cubic feet of natural gas per day
mmcfe	millions of cubic feet of natural gas equivalent
mmcfe/d	millions of cubic feet of natural gas equivalent per day
bcf	billions of cubic feet of natural gas
GJ	gigajoule
mmbtu	millions of British thermal units
m^3	cubic metres
m^3/d	cubic metres per day
km	kilometres
MW	megawatts

Places and Currencies

U.S.	United States
U.K.	United Kingdom
B.C.	British Columbia
$ or Cdn$	Canadian dollars
US$	United States dollars
£	Pounds sterling
€	Euros

Products, Markets and Processes

WTI	West Texas Intermediate
WCS	Western Canadian Select
NGL(s)	natural gas liquid(s)
LPG	liquefied petroleum gas
SCO	synthetic crude oil
NYMEX	New York Mercantile Exchange
TSX	Toronto Stock Exchange
NYSE	New York Stock Exchange
SAGD	steam-assisted gravity drainage
PSC	production sharing contract
EPSA	exploration and production sharing agreement

Suncor converts certain crude oil and NGL volumes to mmcfe or mmcfe/d on the basis of one bbl to six mcf, and certain natural gas volumes to boe, mboe, mmboe or mboe/d on the same basis. Any figure presented in mcfe, mmcfe, mmcfe/d, boe, boe/d, mboe, mmboe or mboe/d may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or NGL to six mcf 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. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Conversion Table [(1)(2)]

1 m^3 liquids = 6.29 barrels
1 m^3 natural gas = 35.49 cubic feet
1 m^3 overburden = 1.31 cubic yards

1 tonne = 0.984 tons (long)
1 tonne = 1.102 tons (short)
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.

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 further 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 the issued and outstanding shares on a two-for-one basis.

Pursuant to an arrangement (the Arrangement), which was completed effective August 1, 2009, Suncor amalgamated with Petro-Canada 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 common shares of the continuing Suncor entity for each Petro-Canada common share held and Suncor shareholders received one common share of the continuing Suncor entity for each common share held.

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

Intercorporate Relationships

Material subsidiaries, each of which was owned 100%, directly or indirectly, by the company as at December 31, 2011 are as follows:

Name	Jurisdiction where organized	Description
Canadian operations		
Suncor Energy Oil Sands Limited Partnership	Canada	This partnership holds most of the company's oil sands assets.
Suncor Energy Ventures Partnership	Canada	This partnership was created in 2011 and holds the company's interest in the Syncrude joint venture.
Suncor Energy Products Partnership	Canada	This partnership holds substantially all of the company's Canadian refining and marketing assets.
Suncor Energy Oil & Gas Partnership	Canada	This partnership holds certain upstream Canadian oil and gas assets.
Suncor Energy Joslyn Partnership	Canada	This partnership holds our working interest in the Joslyn joint venture.
Suncor Energy Products Inc.	Canada	A subsidiary of Suncor Energy Inc. that holds interests in the company's energy marketing and renewable energy businesses, and which is a partner of Suncor Energy Products Partnership.
Suncor Energy Marketing Inc.	Canada	A subsidiary of Suncor Energy Products Inc. through which the products produced by our upstream North American businesses are marketed. Through this subsidiary, we also administer Suncor's energy trading activities, market certain third-party products, procure crude oil feedstocks and natural gas for our downstream business, and procure and market NGLs and LPG for our downstream business.

Name	Jurisdiction where organized	Description
U.S. operations		
Petro-Canada U.S. Holdings Ltd.	U.S.	A subsidiary of Suncor Energy Inc. that holds the majority of our U.S. interests.
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.
International operations		
3908968 Canada Inc.	Canada	A subsidiary of Suncor Energy Inc. that holds certain of our international interests.
Suncor Energy UK Holdings Ltd.	U.K.	A subsidiary of 3908968 Canada Inc. that holds certain of our U.K. interests. Formerly Petro-Canada U.K. Holdings Limited.
Suncor Energy UK Limited	U.K.	A subsidiary of Suncor Energy UK Holdings Ltd. through which certain of our operations are conducted in the U.K. Formerly Petro-Canada U.K. Limited.
Petro-Canada Cooperative Holding U.A.	The Netherlands	A subsidiary of 3908968 Canada Inc. that holds certain of our international interests.
Petro-Canada (International) Holdings B.V.	The Netherlands	A subsidiary of Petro-Canada Cooperative Holding UA that holds certain of our international interests.
Petro-Canada Palmyra B.V.	The Netherlands	A subsidiary of Petro-Canada (International) Holdings BV that holds the majority of our interests in Syria.
Petro-Canada Germany GmbH (1)	Germany	A subsidiary of Petro-Canada (International) Holdings BV that holds the majority of our interests in Libya.
Petro-Canada Oil (North Africa) GmbH (2)	Germany	A subsidiary of Petro-Canada Germany GmbH through which the majority of our Libya operations are conducted.

(1) Subsequent to December 31, 2011, Petro-Canada Germany GmbH changed its name to Suncor Energy Germany GmbH.

(2) Subsequent to December 31, 2011, Petro-Canada Oil (North Africa) GmbH changed its name to Suncor Energy Oil (North Africa) GmbH.

Individually, the company's remaining subsidiaries accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2011, and (ii) less than 10% of the company's consolidated sales and operating revenues for the fiscal year ended December 31, 2011. 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 market third-party petroleum products. We also carry on energy trading activities focused principally on the marketing and trading of crude oil, natural gas, refined products and byproducts.

Suncor has classified its operations into the following segments:

OIL SANDS

Suncor's Oil Sands segment, with assets located in northeast Alberta, recovers bitumen from mining and in situ operations and upgrades the majority of this production into refinery feedstock, diesel fuel and byproducts. The Oil Sands segment includes:

- **Oil Sands** operations refers to Suncor's wholly owned and operated mining, extraction, upgrading and in situ assets in the Athabasca oil sands region. Oil Sands activities consist of:
    - **Oil Sands Base** operations include the Millennium and Steepbank (including the North Steepbank Extension) mining and extraction operations, two integrated upgrading facilities known as Upgrader 1 and Upgrader 2, and the associated infrastructure for these assets – including utilities, energy and reclamation facilities, such as Tailings Reduction Operations (TRO_{TM}) assets.
    - **In Situ** operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, such as central processing facilities and cogeneration units. The majority of In Situ production is upgraded by Oil Sands Base; however, the company's marketing plan includes sales of bitumen when marketing conditions are favourable or as operating conditions at Oil Sands Base require.
- **Oil Sands Ventures** includes the company's interests in significant growth projects, including two where Suncor is the operator – the Fort Hills mining (40.8%) and the Voyageur upgrader (51%) projects, and one where Total E&P Canada Ltd. (Total E&P) is the operator – the Joslyn mining project (36.75%). Oil Sands Ventures also includes the company's 12% interest in the Syncrude oil sands mining and upgrading joint venture.

EXPLORATION AND PRODUCTION

In January 2011, Suncor combined its International and Offshore and Natural Gas segments into the Exploration and Production segment, which consists of offshore operations off the east coast of Canada and in the North Sea, and onshore operations in North America, Libya and Syria.

- **East Coast Canada** operations include Suncor's 37.675% working interest in Terra Nova, for which Suncor is the operator. Suncor also holds a 20% interest in the Hibernia base project and a 19.5% interest in the Hibernia Southern Extension Unit (HSEU), a 27.5% interest in the White Rose base project and a 26.125% interest in the White Rose Extensions, and a 22.729% interest in Hebron, all of which are operated by other companies.
- **International** operations include Suncor's 29.89% working interest in Buzzard and a 26.69% interest in the Golden Eagle Area Development (Golden Eagle) – both of which are operated by another company – in the U.K. portion of the North Sea. Suncor also holds interests in several North Sea licences offshore the U.K. and Norway. Suncor owns, pursuant to a Production Sharing Contract, an interest in the Ebla gas development in the Ash Shaer and Cherrife areas in Syria. Suncor also owns, pursuant to Exploration and Production Sharing Agreements, working interests in the exploration and development of oilfields in the Sirte Basin in Libya.

  Due to recent unrest in both countries, the company has declared force majeure under its contractual obligations in Libya and Syria. Operations in Libya are in the process of restarting, while operations in Syria have been suspended indefinitely.
- **North America Onshore** operations include Suncor's interests in a number of assets in Western Canada, which primarily produce natural gas.

REFINING AND MARKETING

Suncor's Refining and Marketing segment consists of two primary operations:

- **Refining and Product Supply** operations refine crude oil into a broad range of petroleum and petrochemical products. Eastern North America operations include refineries located in Montreal, Quebec and Sarnia, Ontario, and a lubricants

business located in Mississauga, Ontario that manufactures, blends and markets products worldwide. Western North America operations include refineries located in Edmonton, Alberta and Commerce City, Colorado. Other assets include interests in a petrochemical plant, pipelines and product terminals in Canada and the U.S.

- Downstream **Marketing** operations sell refined petroleum products and lubricants to retail, commercial and industrial customers through a combination of company-owned, branded-dealer and other retail stations in Canada and Colorado, a nationwide commercial road transport network in Canada, and a bulk sales channel in Canada.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

The grouping **Corporate, Energy Trading and Eliminations** includes the company's investments in renewable energy projects, results related to energy supply and trading activities, and other activities not directly attributable to any other operating segment.

- **Renewable Energy** interests include six operating wind power projects and the St. Clair ethanol plant in Ontario.

- **Energy Trading** activities primarily involve the marketing and trading of crude oil, natural gas, refined petroleum products and byproducts and the use of midstream infrastructure and financial derivatives to optimize related trading strategies.

- **Corporate** includes stewardship of Suncor's debt and borrowing costs, expenses not allocated to the company's businesses, and the company's captive insurance activities that self-insure a portion of the company's asset base.

- Intersegment revenues and expenses are removed from consolidated results in **Group Eliminations**. Intersegment activity includes the sale of feedstock by the Oil Sands and Exploration and Production segments to the Refining and Marketing segment, the sale of fuels and lubricants by the Refining and Marketing segment to the Oil Sands segment, the sale of ethanol by the Renewable Energy business to the Refining and Marketing segment, and the provision of insurance for a portion of the company's operations by the Corporate captive insurance entity.

Three-Year History

2009

- **Economic downturn leads to "safe mode" for key growth projects.** In the first quarter of 2009, Suncor placed a number of oil sands projects into safe mode as a result of the downturn in the global economy. Safe mode is the deferral of projects and maintenance of equipment and facilities in a safe manner in order to expedite remobilization when appropriate. The placement and maintenance of projects in safe mode resulted in significant operating expenses in 2009 and 2010, and the ensuing changes to project scheduling resulted in increased capital expenditures when projects were eventually remobilized. As a result of the merger and an improvement in the economy, in 2010, Firebag Stage 3, Firebag Stage 4 and the Millennium Naphtha Unit (MNU) projects were all taken out of safe mode. The Voyageur upgrader project began remobilizing in 2011.

- **Merger with Petro-Canada.** On August 1, 2009, Suncor merged with Petro-Canada, adding approximately 375 mboe/d of upstream production at that time, which included the MacKay River in situ bitumen project, a 12% ownership interest in the Syncrude joint venture, interests in all of the major producing fields offshore Newfoundland and Labrador, interests in several offshore fields in the U.K. and the Netherlands portions of the North Sea, including Buzzard, interests in foreign operations pursuant to PSCs in Syria and Libya, and significant natural gas assets in Western Canada and the U.S. Rockies. Growth assets acquired included the Fort Hills oil sands mining project, other extensive oil sands acreage considered prospective for in situ development of bitumen resources, and interests in other North Sea fields that would eventually become known as Golden Eagle. Downstream assets acquired included the Edmonton and Montreal refineries, a lubricants plant, and the Petro-Canada$_{TM}$ branded network of retail service stations and wholesale cardlock sites. In addition, responsibilities for crude marketing and procurement activities related to Petro-Canada assets were assumed by Suncor's existing Energy Trading business.

- **Steepbank extraction plant completed.** To reduce the distance to the mine face, a new bitumen extraction plant on the east side of the Athabasca River was completed, resulting in improved reliability and bitumen recovery.

- **Fires at Suncor's upgrading facilities.** In December 2009, there was a fire at the company's Upgrader 2 facilities, which were repaired and returned to normal operations in February 2010. In February 2010, there was a fire at our Upgrader 1 facilities, which were repaired and returned to full operations by April 2010.

2010

- **Disposition of non-core assets.** Subsequent to the merger, the company undertook a strategic initiative to sell non-core assets. Throughout 2010, the company completed or entered into agreements for the disposition of non-core assets representing approximately 60 mboe/d of production. This included assets in the U.S. Rockies, the Netherlands portion of the

North Sea, Trinidad and Tobago, the Scott, Telford and Guillemot areas in the U.K. portion of the North Sea, and numerous natural gas packages in Western Canada. Some of these disposals closed in 2011. Additional disposals of non-core North America Onshore assets representing approximately 5.9 mboe/d of 2010 production occurred in 2011.

- **Reclamation of tailings pond.** 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 renamed the area Wapisiw Lookout.

- **Tailings Reduction Operations (TRO$_{TM}$).** Suncor received approval from Alberta regulators to convert from the Consolidated Tailings (CT) management process to TRO$_{TM}$, a process in which mature fine tailings are dried, rather than mixed with sand and other materials to form CT. Suncor expects that TRO$_{TM}$ will allow the company to significantly reduce the area required for tailings management, increase the speed at which it is able to reclaim its tailings ponds and meet the requirements of the Tailings Directive approved by Alberta's Energy Resources Conservation Board (ERCB) in 2009.

- **Production commences in Syria.** Suncor achieved commercial production of natural gas from the Ebla project in April. First oil was later achieved from Ebla in December.

- **First oil from the White Rose Extensions.** In the second quarter, first oil was achieved from the North Amethyst portion of the White Rose Extensions.

- **Terra Nova redetermination.** In December, the joint venture 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%.

- **Transformation of downstream Marketing operations.** Suncor rebranded 158 Sunoco$_{TM}$ retail sites to consolidate its post-merger Canadian downstream marketing operations under the Petro-Canada$_{TM}$ brand. Suncor divested 104 retail sites in Ontario to comply with Canadian Competition Bureau requirements relating to the merger.

- **Suncor announced plans to grow production to one million barrels of oil equivalent per day.** In December, Suncor announced that it had entered into agreements with Total E&P. Concurrent with this announcement, Suncor introduced its long-term growth strategy to increase production to over one million boe/d by 2020. Key components of the plan included arrangements with Total E&P for the restart of construction of the Voyager upgrader, and the joint development of the Fort Hills and Joslyn mining projects with the respective joint venture owners of these projects. Other key components of the ten-year growth strategy included continued development of the company's Firebag and MacKay River in situ projects, and investments in, and ongoing production from, international and offshore operations.

2011

- **Exploration and Production segment created.** In January, Suncor announced organizational changes that included the International and Offshore and Natural Gas business divisions merging into a single organization primarily focused on conventional production, which includes both onshore and offshore operations.

- **Ethanol plant expansion completed.** In January, Suncor completed the expansion of its ethanol plant in Ontario that doubled production capacity to 400 million litres per year, making it Canada's largest biofuels production facility.

- **Operations in Libya temporarily suspended.** In response to political unrest and sanctions in Libya in the first quarter, the joint venture operator shut in production, while Suncor suspended all exploration activities and declared force majeure under its EPSAs. The uncertainty about the company's future in Libya caused by these events at that time resulted in the company recording an impairment charge against the company's assets. Sanctions in Libya were eventually lifted upon the transition to a new government, and the joint venture operator was able to restart production from all major producing fields by early January 2012.

- **Transactions with Total E&P close.** After receiving the necessary regulatory approvals, Suncor and Total E&P completed their previously announced transactions. In exchange for net proceeds of $1.820 billion (after closing adjustments) and a 36.75% interest in the Joslyn project, Suncor sold to Total E&P a 49% interest in the Voyageur upgrader and a 19.2% interest in the Fort Hills project.

- **Largest turnaround in Suncor history.** During the second quarter, the company completed safely and on time a turnaround at its Upgrader 2 facilities.

- **New wind farms commissioned.** In May, the eight-turbine, 20-MW Kent Breeze wind power project in southwest Ontario commenced operations. In November, Suncor completed construction of, and initiated full production from, the 55-turbine, 88-MW Wintering Hills project in southern Alberta.

- **First oil at Firebag Stage 3.** In July, Suncor achieved first oil from the first of three well pads at the Firebag Stage 3 expansion. With the ramp up of production from the Stage 3 expansion and the addition of infill wells at Firebag, Suncor's In Situ production surpassed 100,000 bbls/d of bitumen for the first time in the fourth quarter.

- **Development of Golden Eagle approved.** In the third quarter, the field development plan for Golden Eagle was approved. The company anticipates first production late in 2014 or early 2015.

- **North Steepbank Extension.** In December, the company started mining ore from the North Steepbank Extension (NSE) at its Oil Sands Base operations. The opening of this new mine extension enables Suncor to access additional oil sands ore, decrease overall haul distances and decrease mine congestion.

- **Operations in Syria suspended.** In December, sanctions were introduced that resulted in Suncor declaring force majeure under its contractual obligations and suspending its operations in Syria. Consequently, the company has ceased recording all production and revenue associated with its Syrian assets.

- **Systems integration project completed.** During the year, the company integrated Exploration and Production and Refining and Marketing assets acquired in the merger onto a common information systems platform. Oil Sands and Corporate assets were integrated during 2010.

2012

- **Chief Executive Officer Rick George to retire.** Suncor's long-standing chief executive officer (CEO) announced his plan to retire after more than 20 years leading the company. Steve Williams, Suncor's chief operating officer (COO), was appointed president and a member of the company's Board of Directors, and will assume the role of CEO upon Mr. George's retirement in May 2012.

NARRATIVE DESCRIPTION OF SUNCOR'S BUSINESSES

Oil Sands

For a discussion of environmental and other regulatory conditions, and competitive conditions and seasonal impacts affecting our Oil Sands segment, refer to the Industry Conditions and Risk Factors sections of this AIF.

Oil Sands Base Operations

Our integrated Oil Sands Base operations, located near Fort McMurray, Alberta, involve numerous activities:

- **Mining and Extraction**

After overburden is removed, open-pit mining operations use shovels to excavate the oil sands bitumen ore, which is trucked to sizers and breaker units that reduce the size of the ore, then create a slurry of hot water, rock, sand and bitumen. The slurry is delivered via a hydrotransport pipeline to extraction plants. The raw bitumen is separated from the slurry using a hot water process that creates a bitumen froth. Naphtha is added to the bitumen froth to form a diluted bitumen, which is subsequently sent to a centrifuge plant that removes most of the remaining impurities and minerals.

- **Upgrading**

After the diluted bitumen is transferred to upgrading facilities, the naphtha is removed and recycled to be used again as diluent. Bitumen 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 sulphur and nitrogen using a hydrotreating process. In addition to sweet and sour SCO, upgrading processes also produce diesel, naphtha, kerosene and gas oil.

- **Utilities**

Process water is used in extraction processes and then recycled. Steam and electricity are generated through facilities on site. Steam required for operations is generated by a cogeneration unit or coke-fired boilers. Electricity is generated by turbine generators, some of which are part of the cogeneration unit. Excess energy produced is sold back to the power grid; however, during peak periods, Suncor purchases additional electricity from the grid.

- **Maintenance**

In the normal course of our operations, we regularly conduct planned maintenance events at our facilities. Large planned maintenance events, which require units to be taken offline to be completed, are often referred to as turnarounds. Turnaround maintenance provides opportunities for both preventive maintenance and capital replacement, which are expected to improve reliability and operational efficiency. Planned maintenance events generally occur on routine cycles, determined by historical operating performance, recommended usage factors or regulatory requirements. A turnaround typically involves shutting down the unit, inspecting it for wear or other damage, repairing or replacing components, and then restarting the unit.

- **Reclamation**

Mining processes disturb areas of land that must be reclaimed. Land reclamation activities involve monitoring soil salvage and replacement, wetlands research, fish, waterfowl and other wildlife protection, and re-vegetation.

The extraction process produces tailings that are a mixture of water, clay, sand and residual bitumen. Suncor has developed a new tailings management approach, known as TRO$_{TM}$, which involves converting tailings more rapidly into a solid landscape suitable for reclamation. In this process, mature fine tailings are mixed with a polymer flocculent and then deposited in thin layers on shallow slopes. The resulting product is a dry material that is capable of being reclaimed in place or moved to another location for final reclamation. The new process is expected to eliminate the need for new tailings ponds at existing mining operations, improve tailings management going forward and, in the years ahead, reduce the number of tailings ponds presently in operation.

Oil Sands Base Assets

Mining and Extraction

Suncor pioneered the commercial development of the Athabasca oil sands beginning in 1962. The original mining area is essentially depleted, and, for several years, bitumen has been mined almost exclusively from the Millennium area, which began production in 2001. During 2011, the company mined approximately 160 million tonnes from Millennium, and started mining ore from the NSE.

Suncor currently operates two extraction plants, the second of which was brought into service during 2009. The original extraction plant on the west side of the Athabasca River is operated only as required to support reclamation activities. During 2011, Suncor averaged processing 289,000 bbls/d of mined bitumen ore in its extraction facilities.

Upgrading

Suncor's upgrading facilities consist of two upgraders – Upgrader 1, which has a primary upgrading capacity of 110,000 bbls/d of SCO, and Upgrader 2, which has a primary upgrading capacity of 240,000 bbls/d of SCO. When the MNU is fully commissioned, Suncor's secondary upgrading facilities will consist of three hydrogen plants, three naphtha hydrotreaters, two gas oil hydrotreaters and two diesel hydrotreaters.

During 2011, Suncor averaged 279,700 bbls/d of upgraded bitumen (SCO) production and an additional 25,000 bbls/d of non-upgraded bitumen production (2010 – 251,400 bbls/d upgraded, 31,600 bbls/d non-upgraded).

Other Mining Leases

Suncor owns several other oil sands leases, including those known as Voyageur South and Audet, which it believes can be developed using mining techniques and on which it undertakes modest exploratory drilling programs on a year-to-year basis.

In Situ Operations

Suncor's In Situ operations, Firebag and MacKay River, use SAGD technology to separate bitumen from oil sands deposits that are too deep to be mined economically and primarily provide additional bitumen to Oil Sands Base upgrading facilities.

- **The SAGD process**

The SAGD process drills pairs of horizontal wells with one located above the other. To help reduce land disturbance and improve cost efficiency, well pairs are drilled from central multi-well pads. Steam is injected into the upper well to create a high-temperature steam chamber underground. This process reduces the viscosity of the thick bitumen, allowing heated bitumen and condensed steam to drain into the bottom well and flow up to the surface aided by subsurface pumps or circulating gas. Typically, it takes 18 to 24 months for the steam chamber to reach conditions that support peak production levels.

- **Central processing facilities**

The bitumen and water mixture is pumped to separation units at central processing facilities, where the water is removed from the bitumen, treated and recycled for use in steam generation. To facilitate transportation of viscous bitumen, In Situ operations add diluent (naphtha) or use an insulated (referred to as "hot") bitumen pipeline.

- **Steam generation**

Gas vapours recovered at central processing facilities are treated and used as fuel to power Once Through Steam Generators. Cogeneration units are energy efficient systems, which use natural gas combustion to power turbines that generate electricity and steam.

- **Maintenance and feedstock supply**

Central processing facilities, steam generation units and well pads are all subject to routine inspection and maintenance cycles.

SAGD production volumes are impacted by reservoir quality and the capacity of central processing facilities and steam generation units to process liquids and generate steam. As with conventional oil and gas properties, SAGD wells will experience natural production declines after several years. Suncor strives to maintain bitumen supply by drilling new wells from existing well pads or by developing new well pads.

- **New technologies**

Suncor is involved in numerous pilot projects, both operated and non-operated. These pilot projects evaluate potential enhancements to existing SAGD operations or potential new technologies targeted at improving capital efficiency and lowering SORs.

In Situ Assets

Firebag

Initial development of Suncor's Firebag operations included two well pads, each with ten well pairs, and central processing facilities for each of Firebag Stage 1 and Stage 2, with production commencing in 2004 and 2006, respectively. A cogeneration unit was added in 2007. The combined processing capacity of these initial Firebag operations was approximately 95,000 bbls/d of bitumen at design SORs of 2.0 to 2.5; however, actual SORs for Firebag have been higher than the design specifications, largely due to geological heterogeneity (inconsistent quality throughout the reservoir). Prior to first oil from the Stage 3 expansion, production averaged between 50,000 to 60,000 bbls/d for 2010 and 2011. As at December 31, 2011, the cumulative SOR at Firebag was 3.3. As production from the Stage 3 expansion increases, the Firebag SOR is expected to decrease.

During 2011, the company completed its Firebag Stage 3 expansion, which added three well pads, two cogeneration units and a central processing facility. Commissioning of the cogeneration units is expected to be completed in the first quarter of 2012. The Firebag Stage 4 expansion, scheduled for completion during 2013, includes two well pads, an additional central processing facility and two more cogeneration units. The design capacity for both of the Stage 3 and Stage 4 expansions is 62,500 bbls/d of bitumen. Actual production may vary from this capacity based on steaming and ramp-up periods, scheduled and unscheduled maintenance, reservoir conditions and other factors. Suncor designed the Stage 3 and Stage 4 expansions with the goal of integrating the entire Firebag operation. Steam and electricity generated at one facility or unit can be used at any well pad. Central processing facilities have been designed to be flexible as to which well pads supply bitumen.

Suncor has received regulatory approval for further expansion of Firebag beyond Stage 4 for an aggregate of 368,000 bbls/d of bitumen.

During 2011, Firebag operations averaged production of 59,500 bbls/d of bitumen (2010 – 53,600 bbls/d), approximately 90% of which was upgraded by Oil Sands Base operations.

MacKay River

Production from MacKay River commenced in 2002 from two well pads with 25 well pairs, and subsequent expansion phases added four more well pads with 31 producing well pairs. Starting in June 2011, a new phase of 22 well pairs was initiated, with production coming on-stream in the fourth quarter of 2011 and continuing to build throughout 2012. Central processing facilities have a nameplate capacity of approximately 30,000 bbls/d of bitumen. A third party owns and operates the on-site cogeneration unit in return for a fee and natural gas fuel being purchased by Suncor. As at December 31, 2011, the cumulative SOR at MacKay River was 2.5.

Suncor has regulatory approval for 73,000 bbls/d of bitumen production from MacKay River and is currently evaluating an expansion to add a second central processing facility. Suncor has approval to include its Dover properties in the MacKay River project area, and has submitted an application to develop a portion of these lands.

During 2011, MacKay River operations averaged production of 30,000 bbls/d of bitumen (2010 – 31,500 bbls/d), approximately 30% of which was upgraded by Oil Sands Base operations.

Other In Situ Leases

Suncor owns several other oil sands leases, including those known as Meadow Creek, Lewis, Chard and Kirby, which it believes can be developed using in situ techniques, and on which it may undertake modest exploratory drilling programs on a year-to-year basis.

Oil Sands Ventures – Assets and Operations

Syncrude

Suncor holds a 12% interest in the Syncrude joint venture, also located near Fort McMurray, which includes operations at the Mildred Lake North and Aurora North oil sands mines. Syncrude also has regulatory approval to develop the Aurora South oil sands mining leases.

Syncrude began producing in 1978 and is operated by Syncrude Canada Ltd. (SCL). In 2006, SCL entered into a comprehensive management services agreement with Imperial Oil Resources (Imperial Oil) to provide operational, technical and business management services. This agreement has an initial term of ten years and includes renewal provisions.

Syncrude mining operations use truck, shovel and hydrotransport systems, similar to those at Oil Sands Base. Extraction and upgrading technologies at Syncrude are also similar to those used at Oil Sands Base, except that Syncrude uses a fluid coking process that involves the continuous thermal cracking of the heaviest hydrocarbons, as opposed to a delayed coking process. At Mildred Lake, electricity is provided by a utility plant fuelled by off-gas from upgrading operations and natural gas. At Aurora North, Syncrude operates two 80-MW gas turbine power plants. The gross design capacity for Syncrude facilities is approximately 375,000 bbls/d, but when allowances are made for scheduled and unscheduled downtime the gross productive capacity of the facilities is approximately 350,000 bbls/d.

Syncrude primarily produces a single sweet synthetic light crude product. Marketing of this product is the responsibility of the individual joint venture owners.

Land reclamation activities are similar to those at Oil Sands Base; however, tailings management processes are different. Syncrude's ERCB-approved tailings plan uses the following: freshwater capping, a composite tails mixture of fine tails and gypsum, and plans for centrifuge technology that separates water from tailings.

In 2011, Suncor's share of Syncrude production averaged 34,600 bbls/d (2010 – 35,200 bbls/d).

Voyageur Upgrader, Fort Hills and Joslyn

Oil Sands Ventures also includes assets important to Suncor's long-term growth strategy. During the first quarter of 2011, Suncor completed transactions with Total E&P, which brought Total E&P into the Voyageur upgrader project, increased their working interest in the Fort Hills oil sands mining project and brought Suncor into the Joslyn oil sands mining project.

- Fort Hills is the oil sands mining project comprising leases on the east side of the Athabasca River, north of Oil Sands Base operations. Preliminary designs for Fort Hills plan for 164,000 bbls/d of bitumen production (gross). Suncor originally acquired a 60% working interest in Fort Hills as a result of the merger, and then agreed to a partial disposition of 19.2% as part of transactions with Total E&P. Suncor now holds a 40.8% working interest in the Fort Hills project. Suncor Energy Operating Inc., a wholly owned subsidiary of Suncor, is the contract operator for the Fort Hills project. Prior to the merger, the joint venture owners of Fort Hills had completed design basis memorandum engineering in 2008, but deferred a final investment decision as a result of the economic downturn. Subsequent to completing the transactions with Total E&P, the Fort Hills project has restarted design basis memorandum engineering. Total E&P holds a 39.2% working interest in the Fort Hills project and Teck Resources Limited holds the remaining 20%.

- Joslyn is the oil sands mining project comprising leases southwest of the Fort Hills project and on the west side of the Athabasca River. Preliminary designs for the Joslyn North mine project plan for 100,000 bbls/d of bitumen production (gross). Suncor acquired a 36.75% working interest in this asset as a result of transactions with Total E&P. Under this joint venture agreement, Total E&P is scheduled to act as operator, holding a 38.25% interest, while Occidental Oil and Gas Corporation (15%) and Inpex Canada Ltd. (10%) hold the remaining interests.

- Suncor anticipates that the majority of bitumen production from the Fort Hills and Joslyn projects will be upgraded into SCO and other products by the Voyageur upgrader. Suncor began design work for the Voyageur upgrader in 2004. The original Voyageur program received approval from the Board of Directors in January 2008. The Voyageur upgrader project was placed into safe mode in January 2009 as a result of the economic downturn, at which time construction was approximately 15% complete. Subsequent to the transactions with Total E&P in December 2010, the Voyageur upgrader project team has

engaged in activities such as remobilizing personnel and assessing the condition of assets. Preliminary design plans are for 200,000 bbls/d (gross) of upgrading capacity.

The development of each of these projects is still subject to approval by Suncor's Board of Directors and the joint venture owners for each respective project.

Sales of Principal Products

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

For bitumen production from In Situ operations, Suncor's marketing strategy allows it to take advantage of changes in market conditions by either: a) upgrading the bitumen directly at our Oil Sands Base facilities; b) upgrading the bitumen at Suncor's refineries; or c) selling diluted bitumen directly to third parties. Direct bitumen sales may also be required during outages of upgrading facilities or interruptions in pipeline systems. During 2011, 73% (2010 – 63%) of In Situ bitumen production was processed by Oil Sands Base upgrading facilities.

In 2011, sales of light sweet SCO and diesel represented 44% and sales of light sour SCO and bitumen represented 45% of total Oil Sands segment operating revenues. There were no individual customers that represented 10% or more of Suncor's consolidated revenues in 2011 or 2010.

Operating revenues include sales of non-proprietary volumes purchased from third parties. These volumes are typically transacted when Oil Sands Base or third-party refinery capacities are constrained, in conjunction with a corresponding sales agreement, which allow Suncor and the third party to optimize their logistics. These volumes may also include purchases of third-party diluent to support sales of bitumen, required when the company is unable to meet diluent demands internally.

Information on average daily sales volumes and the corresponding percentage of Oil Sands segment operating revenues by product for each of the last two years are as follows:

Sales Volumes and Operating Revenues – Principal Products	2011		2010	
	mbbls/d	% operating revenues	mbbls/d	% operating revenues
Light sweet SCO and diesel (including Syncrude)	144.4	44	137.9	43
Light sour SCO and bitumen	194.6	45	176.6	46
Non-proprietary, byproducts and other operating revenues	n/a	11	n/a	11
	339.0		314.5	

In the normal course of business, Suncor enters into long-term strategic supply agreements for its proprietary sour SCO, which contain varying terms with respect to pricing, volume, expiry and terminations.

Distribution of Products

Production from Oil Sands Base operations is gathered from our Fort McMurray facilities at the Athabasca Terminal, which is operated by Enbridge Inc. (Enbridge). Suncor has various arrangements with Enbridge at this facility to store SCO, diluted bitumen and diesel. Production from Firebag is transported to the Athabasca Terminal via a pipeline that is operated by Suncor, while production from MacKay River is transported to the Athabasca Terminal via an insulated pipeline.

Product moves from the Athabasca Terminal in the following ways:

- SCO is sent to Edmonton via the Oil Sands pipeline, which is owned by Suncor and operated by the Refining and Marketing segment. At Edmonton, the product is sold to local refiners or transferred onto the Enbridge Mainline system.
- SCO and diluted bitumen is transported to Hardisty, Alberta via Cheecham, Alberta on the Enbridge Athabasca Pipeline.
- SCO also reaches Edmonton via the Waupisoo pipeline, which is owned and operated by Enbridge. This pipeline begins from the Enbridge Athabasca Pipeline at Cheecham.

From Hardisty, where Suncor has storage capacity under contract, Suncor has various options for delivering product to customers:

- SCO reaches Suncor's Commerce City refinery via the Express and Platte pipelines. Suncor owns and operates a pipeline that is connected to the Commerce City refinery, which originates from the Guernsey, Wyoming station that is part of the Platte pipeline.
- SCO reaches Suncor's Sarnia refinery on the Enbridge Mainline and Lakehead systems.

- From Hardisty, which is also connected to the Enbridge Mainline pipeline from Edmonton, crude can reach most major refining hubs via the Enbridge Mainline, Express/Platte and Keystone pipeline systems.

Natural gas is used in the production of SCO, particularly in our SAGD operations. Natural gas is delivered to Oil Sands Base and In Situ facilities via the Nova Gas Transmission Limited (NGTL) regulated pipeline system. Suncor also transports natural gas to our Oil Sands Base facilities on the company-owned and operated Albersun Pipeline, which has a capacity of 46 mmcf/d and extends approximately 300 km south of the Oil Sands Base facilities and is connected to the NGTL.

Oil Sands Base facilities are readily accessible by public road. MacKay River facilities are accessible by a combination of public and private roads. Firebag facilities are currently accessible by air and private road. In 2010, the East Athabasca Highway was constructed to provide access to the Firebag site. This highway is owned by Suncor, Husky Energy Inc. and Imperial Oil Ltd., and was constructed to provide each company with access to its oil sands operations in the area.

Royalty Agreements

New oil sands projects are subject to the New Royalty Framework issued by the Government of Alberta, and regulated by the *Oil Sands Royalty Regulation 2009* (OSRR 2009), and supporting regulations, which were approved on December 10, 2008.

In 2011, Oil Sands royalties (excluding Syncrude) were approximately 7% (2010 – 7%) of Oil Sands operating revenues before royalties, and excluding non-proprietary sales and sales of byproducts. In 2011, Suncor incurred royalties on Syncrude operations averaging approximately 8% of Syncrude gross revenue (2010 – 9%).

Oil Sands Base and Syncrude

As part of the New Royalty Framework, Suncor negotiated and entered into the Suncor Royalty Amending Agreement (Suncor RAA) with the Government of Alberta in January 2008 for royalties pertaining to its Oil Sands Base operations. Prior to the New Royalty Framework, Suncor exercised its option to transition to a bitumen-based royalty from an SCO-based royalty, which became effective January 1, 2009. Royalty rates for 2009 remained at 25% of net revenue. For the period from January 1, 2010 to December 31, 2015, royalty rates are based on a sliding scale (depending on the Canadian dollar equivalent for WTI) from 25% to 30% of R-C (Revenue-Cost), where R is gross revenues, net of bitumen quality adjustments and transportation costs, and C is allowable costs including allowable capital expenditures, which excludes substantially all operating and capital expenditures associated with upgrading facilities. The minimum royalty rate is 1.0% to 1.2% of R. In 2011 and 2010, Suncor incurred royalties on Oil Sands Base mining operations at a rate of 30% of R-C because of high prices for WTI.

In November 2008, the Alberta government and the joint owners of the Syncrude joint venture reached an agreement for the implementation of the New Royalty Framework for the Syncrude project (similar to the Suncor RAA). Under the new terms, Syncrude would continue paying the greater of 1% gross revenue, or 25% of net revenue, until the end of 2015. For 2011, the royalty rate was 25% of net revenue. As part of its agreement, Syncrude also exercised its option to transition to a bitumen-based royalty from an SCO-based royalty. As such, the upgrader facility at the Syncrude project is no longer considered a part of the royalty project. The Syncrude joint venture owners agreed to pay an additional royalty of $975 million over a six-year period starting in 2010, which is contingent on achieving certain production levels.

As part of the implementation of the New Royalty Framework, the Alberta government enacted new Bitumen Valuation Methodology (BVM) regulations effective January 1, 2009. These interim BVM regulations determine the valuation of bitumen for 2009 to 2011. Final regulations to establish the BVM calculation for future years are still to be developed by the Crown. For the year 2009, Suncor filed a non-compliance notice with the Crown, citing that reasonable adjustments were not considered by the Crown in the determination of bitumen value as permitted by the Suncor RAA. In December 2010, the Minister of Energy notified Suncor of a modification to the Suncor BVM, permitting adjustments for bitumen quality and transportation. Suncor filed its second non-compliance notice with the Crown, for the years 2009 and 2010, related to the quality adjustment made by the Minister, which Suncor believes is not reasonable. Pursuant to the OSRR 2009, Suncor provided replacement royalty reports for 2009 and 2010 and remitted, under protest, the balance of royalty payable at the end of January 2011. For 2011, Suncor continued to remit royalty payments based on its view of reasonable quality adjustments; however, royalty expense was calculated based on the Minister's quality adjustment. The Suncor RAA provides for an arbitration procedure failing settlement of these issues. Suncor filed a Notice of Commencement of Arbitration with the Crown on January 29, 2011.

The joint venture owners of Syncrude have 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 the Suncor RAA.

Beginning on January 1, 2016, Suncor's Oil Sands Base and Syncrude operations will be subject to the generic royalty regime under OSRR 2009 that is currently in place for all other oil sands royalty projects in Alberta, including Suncor's In Situ operations, as described below.

In Situ

Under the New Royalty Framework, royalties on Suncor's Firebag and MacKay River projects are based on a sliding-scale rate of 25% to 40% of R-C, subject to a minimum royalty of 1% to 9% of R, depending on oil prices for WTI from Cdn$55/bbl to the maximum rate at a WTI price of Cdn$120/bbl. A project remains subject to the minimum royalty (the pre-payout phase) until the project's cumulative gross revenue exceeds its cumulative costs, including an annual investment allowance (the post-payout phase). In 2011, Suncor incurred royalties at a rate of 34% of R-C for MacKay River, which reached the post-payout phase in November 2010, and royalties averaging 6% of R for Firebag, which continues in the pre-payout phase.

Exploration and Production

For a discussion of the environmental and other regulatory conditions, competitive conditions, foreign operations and seasonal impacts affecting our Exploration and Production segment, refer to the Industry Conditions and Risk Factors sections of this AIF.

East Coast Canada – Assets and Operations

Based in St. John's, Newfoundland and Labrador, this business focuses on high-volume production from three existing fields, interests in future developments and expansions, and exploration drilling for new opportunities. Suncor holds a unique position as the only company with interests in all current producing fields.

Terra Nova

The Terra Nova oilfield is approximately 350 km southeast of St. John's, Newfoundland. Terra Nova was discovered by Petro-Canada in 1984, and was the second oilfield to be developed offshore Newfoundland and Labrador. Operated by Suncor, the production system uses a Floating Production, Storage and Offloading (FPSO) vessel that is moored on location, and has gross production capacity of 180,000 bbls/d and oil 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 Terra Nova began in January 2002. At December 31, 2011, there were 28 wells in operation: 16 oil wells, nine water injection wells and three gas injection wells. Two of the oil wells have been shut in due to hydrogen sulphide (H_2S) flow line restrictions. In 2011, Suncor's share of Terra Nova production averaged 16,200 bbls/d (2010 – 23,200 bbls/d).

H_2S was detected in several oil wells in the fourth quarter of 2010. Wells and facilities directly and indirectly impacted by H_2S have been shut in while the company implements its mitigation plan to safely address the situation. In the fourth quarter of 2011, the company replaced a flow line that has remediated some of the H_2S issues. Remaining H_2S remediation is anticipated to be completed as part of the dockside maintenance program scheduled to commence in the third quarter of 2012. The dockside maintenance program also includes replacement of the FPSO swivel.

In December 2010, the joint venture 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.

Field production is transported by shuttle tanker from the FPSO and either delivered directly to customers (if tanker schedules permit) or to the Newfoundland transshipment terminal in Placentia Bay, where it is subsequently loaded onto tankers for transport to markets in Eastern Canada or the U.S. Suncor has a 14% ownership interest in the transshipment facility and is part of a group of companies that share the operation of marine transportation assets for East Coast Canada.

Hibernia and the Hibernia Southern Extension Unit (HSEU)

The Hibernia oilfield, encompassing the Hibernia and Ben Nevis Avalon reservoirs, is approximately 315 km 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) that sits on the ocean floor, and has gross production capacity of 230,000 bbls/d and oil storage capacity of 1.3 mmbbls. Actual production levels are lower, reflecting current reservoir capability and natural declines. Hibernia commenced production in November 1997. At December 31, 2011, there were 64 wells in operation: 35 oil wells, 23 water injection wells and six gas injection. In 2011, Suncor's share of Hibernia production averaged 30,900 bbls/d (2010 – 30,900 bbls/d). Hibernia uses the same transshipment terminal and system of shuttle tankers that are used for Terra Nova.

Final fiscal agreements were signed between the Hibernia joint venture owners and the Government of Newfoundland and Labrador in 2010 that established the fiscal, equity and operational principles for the development of the HSEU. During 2011, the first two development wells were completed and are producing oil. Current development plans include drilling up to two additional producing wells and five water injection wells in a subsea, excavated drill centre, known as a glory hole. The number of producing and injection wells required may be revised as the development proceeds and uncertainties about reservoir capability are resolved.

White Rose and the White Rose Extensions

White Rose, the third oilfield development offshore Newfoundland, is about 350 km southeast of St. John's. Operated by Husky Oil Operations Limited, White Rose uses a FPSO vessel and has gross production capacity of 140,000 bbls/d and oil storage capacity of 940,000 bbls. Production from White Rose began in November 2005. At December 31, 2011, there were 25 wells in operation: twelve oil wells and 13 water injection wells. In 2011, Suncor's share of White Rose production averaged 18,500 bbls/d (2010 – 14,500 bbls/d). White Rose uses the same transshipment terminal and the same system of shuttle tankers that are used for Hibernia and Terra Nova.

In 2007, the White Rose joint venture owners signed a formal agreement with the Province of Newfoundland and Labrador for the development of the White Rose Extensions, which include the South White Rose Extension, North Amethyst and West White Rose satellite fields. In May 2010, first oil was achieved in North Amethyst, and development drilling is ongoing. Development of the West White Rose Extension will be divided into two stages. The first stage was approved in 2009 and first oil was achieved during the third quarter of 2011 with the completion of the first production well. A water injection well to support this initial production is expected to be completed in the second quarter of 2012. Results of the first stage, combined with other ongoing evaluation, will help define the scope of the second stage.

An extended, 18-week off-station maintenance program is scheduled to commence in the second quarter of 2012 for the White Rose FPSO, primarily to address issues with the FPSO propulsion system.

Hebron

Discovered in 1980, the Hebron oilfield is located 340 km southeast of St. John's. In 2008, the Hebron joint venture owners reached an agreement with the Government of Newfoundland and Labrador on commercial terms allowing development activities to proceed. The project is operated by ExxonMobil Canada Properties.

Development of the Hebron project anticipates the construction of a concrete GBS that supports an integrated topsides deck to be used for production, drilling and accommodations. Development plans include 1.2 mmbbls of oil storage capacity and 52 well slots with a gross oil production capacity of 150,000 bbls/d.

The contract for the front-end engineering and design of topsides, procurement and construction was awarded in September 2010. Initial construction on the GBS began in September 2011 in Newfoundland and Labrador. The decision from the joint venture owners of Hebron to sanction the development of Hebron is anticipated in late 2012, with initial production anticipated in late 2017.

Other Assets

The Ballicatters discovery well, located 22 km northeast of Hibernia, was completed earlier in 2011 and is comprised of gas and oil. Suncor and its partner are currently evaluating potential options to commercialize the discovery.

Suncor continues to pursue opportunities offshore Newfoundland and Labrador. The company holds interests in 48 other significant discovery licences and six other exploration licences offshore Newfoundland and Labrador.

International – Assets and Operations

Buzzard – North Sea

The Buzzard oilfield is located in the Outer Moray Firth, 95 km northeast of Aberdeen, Scotland. Operated by Nexen Petroleum U.K. Limited, the Buzzard facilities have gross installed production capacity of approximately 220,000 bbls/d of oil and 80 mmcf/d of natural gas. Oil production rates at Buzzard are currently limited to a maximum of approximately 215,000 bbls/d due to restrictions on third-party pipeline systems. Work is ongoing with the pipeline operator to increase the maximum production rate closer to the gross oil production capacity. Buzzard commenced production in January 2007. Buzzard consists of four bridge-linked platforms supporting wellhead facilities, production facilities, living quarters and utilities, and sulphur handling. In 2011, commissioning was completed for the fourth platform, which was installed to remove H_2S from oil production from some segments of the field. At December 31, 2011, there were 40 wells in operation: 29 oil and gas wells and 11 water injection wells. In 2011, Suncor's share of Buzzard production averaged 42,900 boe/d (2010 – 55,500 boe/d).

Crude oil is transported via the third-party operated Forties Pipeline System to the Kinneil terminal in Scotland. Natural gas is transported via the third-party operated Frigg pipeline to the St. Fergus gas terminal in Scotland.

Golden Eagle – North Sea

During 2011, the Golden Eagle Area Development received regulatory approval from the U.K. Department of Energy and Climate Change. This development is approximately 70 km from the Aberdeen shore and consists of the unitization of the Pink, Hobby and Golden Eagle discoveries completed from 2007 to 2009. The development plan incorporates a combined production, utilities and accommodation platform, linked to a separate wellhead platform, with an initial gross production rate of 70,000 boe/d (gross) from 20 development wells. The operator, Nexen Petroleum U.K. Limited, estimates that the gross

development cost will be £2 billion (Cdn$3.3 billion). First production is expected late in 2014 or early 2015. The joint venture owners of Golden Eagle also hold adjacent exploration licences and continue to explore the region.

Beta – North Sea

In the Norway portion of the North Sea, Suncor is the operator of the Beta discovery. Suncor has a 65% working interest in this field, which is currently under evaluation. The company completed the first exploration well in early 2010, encountering hydrocarbons. An appraisal well was drilled and tested later in 2010 with positive results. Suncor has secured a rig to drill a third appraisal well, which is scheduled to commence in the second quarter of 2012.

Other Assets – North Sea

During 2011, the operator for the PL405 licence (in the Norway portion of the North Sea) in which Suncor has a 30% interest, drilled an exploration well resulting in a discovery, referred to as the Butch prospect. A sidetrack well subsequently drilled at this prospect was abandoned early in 2012, due to well instability, before reaching its intended depth. In the U.K. portion of the North Sea, Suncor, as operator, has secured a rig and expects to drill a joint exploration well for the Romeo joint venture prospect (Block 30/11c). The joint well is to be drilled to comply with work commitments for two adjacent licences, one held by Suncor and its co-venturers, and the other by Total E&P U.K. Limited.

In late 2010 and early 2011, the company disposed of non-core assets in the U.K portion of the North Sea, including its working interests in production from the Guillemot and Scott/Telford areas. Also, in August 2010, the company disposed of non-core assets in the Netherlands portion of the North Sea.

Syria

Located in the Central Syrian Gas Basin, the Ebla project includes all hydrocarbons in the Ash Shaer and Cherrife development areas, which cover more than 300,000 acres. Suncor conducts its Syrian operations pursuant to a PSC, under which the company is a joint owner of the Ebla project with the General Petroleum Corporation (GPC). Under the PSC, the company pays 100% of the development costs and recovers these costs from a 40% share of production after deduction for royalties of 12.5%. This petroleum revenue is referred to as Cost Recovery petroleum. The amount by which Cost Recovery petroleum exceeds recoverable cost is referred to as Excess Cost Recovery petroleum; 50% of this amount is due to the GPC and the remaining 50% is shared between Suncor and the GPC according to a profit-sharing schedule. The Ebla PSC expires in April 2035, but includes a five-year extension subject to GPC approval. First commercial gas production from Ebla was achieved in April 2010 and first oil was achieved in December 2010. In 2011, Suncor's share of production in Syria averaged 17,600 boe/d (2010 – 11,600 boe/d).

The Ebla development comprises six natural gas producing wells in the Ash Shaer field, a gas gathering and compression station, approximately 80 km of pipeline, and a gas treatment plant. The facility is designed to produce 97 mmcf/d of natural gas, along with related LPG and condensate volumes. Natural gas is delivered into the Syrian national gas grid for domestic consumption. The Ebla development also includes three wells producing crude oil, which is sold to the GPC.

In December 2011, amid continuing unrest in Syria, sanctions were introduced and Suncor declared force majeure under its contractual obligations and suspended its operations in the country. Suncor withdrew its expatriate staff and undertook measures to maintain support for its Syrian employees. Consequently, the company has ceased recording all production and revenue associated with its Syrian assets.

Libya

In Libya, Suncor acts pursuant to several EPSAs that enable Suncor and the Libya National Oil Corporation (NOC) to jointly design and implement the redevelopment of existing fields in the Sirte Basin. Existing reserves are associated with five separate agreements (EPSAs I through V), which contain five primary production fields. Under the EPSAs, the company pays 100% of the exploration costs, 50% of the development and 12% of the operating costs, and recovers these costs from a 12% share of production, also referred to as Cost Recovery. Any petroleum remaining after Cost Recovery is referred to as Excess Petroleum, and is shared between Suncor and the NOC based on a profit-sharing schedule affected by several factors, with Suncor's share of profit ranging from 4% to 12%. The EPSAs expire on December 31, 2032, but include an initial five-year extension through the end of 2037. In 2011, Suncor's share of production in Libya averaged 12,100 bbls/d (2010 – 35,200 bbls/d). Libya is a member of the Organization of Petroleum Exporting Countries (OPEC) and is subject to quotas that can affect the company's production in Libya.

For most of the period from March to September 2011, the operator for the joint venture, Harouge Oil Operations BV (Harouge) shut in production as a result of political unrest that began earlier in the year. Sanctions prohibiting the purchase of oil from Libya, among other things, were also introduced by many governments. In March 2011, Suncor declared force majeure under its EPSAs. Beginning late in the third quarter of 2011, a new governing authority was formed in Libya and sanctions were lifted. By January 2012, Harouge had successfully restarted production from all major producing fields and work continues to stabilize production levels. Net production exiting December 2011 was approximately 30,000 bbls/d. Suncor remains optimistic about a gradual return to full operations in Libya and is working to remove its ESPAs from force majeure, where possible.

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, 2011, the undiscounted value of Suncor's remaining obligation is US$347 million, payable in several instalments through 2013. In addition, as part of its contractual obligations under the EPSAs, Suncor is the exploration operator and has committed to fully fund an exploration program, at an estimated remaining cost of US$360 million. As at December 31, 2011, Suncor is still under condition of force majeure with respect to its EPSAs and has re-engaged Harouge to discuss current operations and future plans, including contractual obligations.

North America Onshore – Assets and Operations

The North America Onshore business includes the assets and operations previously reported under Suncor's Natural Gas segment, which is now part of the Exploration and Production segment. This business explores for, develops and produces natural gas, NGLs, crude oil and byproducts in Western Canada. After the merger with Petro-Canada, this business implemented a strategy with greater emphasis on liquids-rich and unconventional sources, and, as a result, disposed of a number of non-core assets throughout 2010 and 2011.

Given the vast amount of natural gas brought on-stream in North America by recent advances in shale gas technology, coupled with the economic downturn in 2008 and 2009, natural gas producers in North America continue to face relatively low gas prices. In light of this environment, Suncor has implemented a strategy to make its operations in this region more profitable. One component of that strategy involved selling assets that were no longer deemed core to Suncor's business strategy. As market conditions for such divestitures worsened, Suncor has started to focus more on another component of its strategy – becoming more profitable in this region, primarily by increasing activity in tight oil projects. The company is also assessing and pursuing activities to grow the unconventional side of its North America Onshore operations.

In 2011, Suncor's share of production from its North America Onshore properties was 388 mmcfe/d (2010 – 575 mmcfe/d) with approximately 21 mmcfe/d of production in 2011 coming from assets that were disposed throughout the year (2010 – 143 mmcfe/d). Natural gas represented 92% of production in 2011 (2010 – 91%), with crude oil and NGL production representing the remainder. North America Onshore also sells sulphur, a byproduct of processing operations.

Operations are primarily focused on multiple geological zones throughout Western Canada. The business is structured with the following asset areas:

Zone / Area	Primary Focus	2011 mmcfe/d
Northeast B.C.	Montney, Triassic and Slave Point	113
Southeast Alberta	Sweet, dry gas	70
Foothills – western Alberta, portions of northeast B.C.	Mississippian sour gas	161
Plains – western Alberta	Cardium oil, Cretaceous gas	44
		388

In addition, Suncor holds assets that could allow the company to eventually explore long-term supply opportunities in northern frontier areas.

Natural gas extracted from the wellhead requires further processing. In Western Canada, Suncor operates several natural gas processing plants, with total licensed capacity of 772 mmcf/d, of which the company's share is 470 mmcf/d. Capacity not utilized by the company's own production is optimized through processing agreements with third-party producers. 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. The following table shows Suncor's working interest ownership and the licensed capacity of operated processing plants as at December 31, 2011.

Suncor Operated Natural Gas Processing Plants	Zone / Area	Working Interest Ownership %	Gross Licensed Capacity mmcf/d	Net Licensed Capacity mmcf/d
Hanlan Sour	Foothills	49.86	382.0	190.5
Hanlan Sweet	Foothills	40.73	44.2	18.0
Ferrier	Plains	100.00	120.0	120.0
Gilby East	Plains	100.00	52.4	52.4
Wilson Creek	Plains	52.17	34.6	18.1
Progress	Northeast B.C.	38.01	42.6	16.2
Boundary Lake Sour	Northeast B.C.	50.00	46.0	23.0
Boundary Lake Sweet	Northeast B.C.	100.00	20.0	20.0
Parkland 1	Northeast B.C.	43.98	18.1	8.0
Parkland 2	Northeast B.C.	34.75	11.7	4.1
Total			771.6	470.3

Natural gas production from Alberta is typically sold at the Nova Inventory Transfer point (NIT), which is one of the largest natural gas trading hubs in North America. Natural gas at NIT generally receives a daily or monthly average AECO (Alberta) spot price. Natural gas production from B.C. is typically sold at Station 2, part of the Spectra B.C. transmission system, and receives the Station 2 Gas Daily Index price, but can also be moved on the Alliance Pipeline system to its terminus in Illinois. To provide diversity in access to markets, Suncor holds firm capacity on the Alliance Pipeline system and the TransCanada PipeLines Gas Transmission Northwest Pipeline (GTN). The GTN firm capacity enables Suncor to deliver natural gas to the Pacific Northwest and California markets.

Conventional crude oil production from North America Onshore assets is shipped on pipelines operated by independent pipeline companies. We currently have no pipeline commitments related to the shipment of conventional crude oil. In most sale arrangements, Suncor is responsible for transportation to the point of sale.

Sales of Principal Products

Oil and gas production from East Coast Canada and the North Sea, and substantially all production from North America Onshore, are sold to our Energy Trading business, which then markets the products to customers under direct sale arrangements. Suncor does not typically enter into long-term supply arrangements to sell its production from its Exploration and Production segment. 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 generally determined on a daily or monthly basis in relation to a specified market reference price.

In Syria, the company entered into purchase and sale agreements with the Syrian government for all hydrocarbon production from the Ebla project. In Libya, hydrocarbon production is marketed by the Libyan government on behalf of Suncor.

For each of Exploration and Production's operations, and for Exploration and Production in total, the following table provides information on average sales volumes for principal products and the corresponding percentage of operating revenues for 2011 and 2010:

Sales Volumes	2011		2010	
	mboe/d	% operating revenues	mboe/d	% operating revenues
East Coast Canada [1]				
Crude oil	52.3	42	54.2	29
International				
Crude oil and NGLs	62.4	34	111.1	46
Natural gas	14.0	4	21.5	4
North America Onshore				
Crude oil and NGLs	5.1	3	8.8	4
Natural gas	59.6	8	87.0	13
Total Exploration and Production				
Crude oil and NGLs	119.8	79	174.2	79
Natural gas	73.6	12	108.5	17

(1) Operating revenues for East Coast Canada include crude oil marketed on behalf of our partner in White Rose.

Royalty Agreements

East Coast Canada

The Terra Nova royalty consists of a sliding-scale, basic royalty payable throughout the project's life, with two tiers of incremental royalties, which became payable upon the achievement of specified levels of profitability that included an additional return allowance. The basic royalty is now capped at 10% of gross field revenue, based on the project reaching a specified cumulative production level. The tier one royalty is the greater of the basic royalty or 30% of net revenue, and became payable in 2005. Net revenue is gross revenue adjusted for eligible operating and capital costs. The tier two royalty, equal to 12.5% of net revenue, became payable in 2008. During 2011, Terra Nova royalty expense averaged 32% of gross revenue (2010 – 35%).

The Hibernia royalty agreement for production from the original oilfields and the AA Block consists of a sliding-scale gross royalty, two tiers of incremental royalty, and an additional net profits interest (NPI). The basic royalty is now capped at 5% of gross revenue, as the project has reached a specified cumulative production level. The tier one royalty, which became payable in 2009, is the greater of the gross royalty or 30% of net revenue. The tier two royalty is 12.5% of net revenue, but has not yet been triggered. Production from the AA Block, which commenced in late 2009, attracts an additional super royalty of 12.5% of net revenue. The NPI, which also became payable in 2009, is an additional 10% of net revenue.

Limited production from the HSEU began in 2011. The HSEU has a similar royalty structure (gross, tier one and tier two) to that described above for Hibernia. Currently, Suncor is only subject to a 5% gross royalty. HSEU production will be subject to an additional super royalty that ranges between 2.5% and 7.5% of net revenue, depending on the price for WTI. The HSEU super

royalty will coincide with the triggering of the tier one net royalty. During 2011, Hibernia (including the HSEU) royalty expense and net profits interest combined to average 37% of gross revenue (2010 – 38%).

The White Rose royalty for the base project consists of a sliding-scale basic royalty payable throughout the project's life, with two tiers of incremental royalties, which became payable upon the achievement of specified levels of profitability that included an additional return allowance. The basic royalty is now capped at 7.5% of gross field revenue, based on the base project reaching a specified cumulative production level. The tier one royalty is the greater of the basic royalty or 20% of net revenue, and became payable in 2007. Net revenue adjusts gross revenue for eligible operating and capital costs. The tier two royalty, equal to 10% of net revenue, became payable in 2008. The White Rose Extensions royalty is similar to the base project, except that there is a tier three royalty, equal to 6.5% of net revenue, which is payable if WTI is greater than Cdn$50/bbl. None of the tier royalties have been triggered for the White Rose Extensions. During 2011, total White Rose royalty expense averaged 14% of gross revenue (2010 – 25%).

International

There are no royalties on oil and gas production from the North Sea; however, in the U.K., oil and gas profits are subject to a 62% income tax rate. For operations in Libya and Syria, all government interests, except for income taxes, are presented as royalties.

North America Onshore

Royalties for Suncor's North America Onshore production in Alberta are regulated by the *Natural Gas Royalty Regulation 2009*, introduced as part of the New Royalty Framework, which came into effect on January 1, 2009, but was later modified by changes that came into effect on January 1, 2011. Royalties for natural gas and conventional oil production are set by a sliding-scale formula – ranging from 5% to 36% for natural gas and 0% to 40% for conventional crude oil – that is dependent on factors such as well depth, production rate, and the price and quality of natural gas and crude oil. The maximum rates of 36% and 40% for the sliding-scales became effective on January 1, 2011 and were both reduced from 50%. NGLs have royalty rates of 30% for propane and butane and 40% for pentanes.

In response to the drop in commodity prices experienced during the second half of 2008, the provincial government introduced the New Well Royalty Reduction Program with the intent of promoting new drilling. New wells drilled after April 1, 2009 are subject to an initial 5% royalty for the first twelve months of production, subject to a 500 mmcfe or 50 mboe volume cap. After May 1, 2010, new wells that started producing exclusively from shale formations qualify for a maximum 5% royalty on all production for the first 36 months of production, and are not subject to volume caps.

The Alberta government's Natural Gas Deep Drilling Program also provides royalty relief for wells drilled beyond 2000 metres (true vertical depth). The maximum royalty rate for these wells is 5%, which applies for five years after the finished drilling date, and is subject to dollar caps that are determined based on total depth and whether the well is exploratory or developmental.

Operating and capital costs for gathering, compressing and processing facilities, and processing costs on a fee-for-service basis are allowable costs for deduction from gas and natural gas liquids gross royalties payable.

Royalties for Suncor's North America Onshore production in British Columbia are regulated primarily by the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation. Royalty rates for natural gas production are subject to different formulas based on the date the well was drilled. Wells drilled before June 1998 attract a rate starting at 15%. Wells drilled after June 1998 attract a royalty starting at 9% or 12%, depending on whether wells were completed within five years of the date drilling rights were issued, and are subject to a sliding scale with a maximum royalty rate of 27% as prices increase. Similar to Alberta, royalty programs exist in British Columbia to provide relief for deep drilling, lower production rates, and unique production methods. Royalties on NGLs are assessed at a flat rate of 20% of sales.

Expenses for field gathering, compression and field processing are allowed as cost of services deductions from gross royalties, and royalty clients who use producer-owned processing facilities or distribution systems are also entitled to operating and capital cost deduction for these facilities.

During 2011, royalty expense for North America Onshore production averaged 11% of gross revenue (2010 – 14%).

Refining and Marketing

For a discussion of the environmental and other regulatory conditions, and competitive conditions and seasonal impacts affecting our Refining and Marketing segment, refer to the Industry Conditions and Risk Factors sections of this AIF.

Operations – Refining and Product Supply

Eastern North America

Effective January 1, 2012, the Montreal refinery had a crude oil capacity of 137,000 bbls/d. The observed performance of the refinery, after improvements in reliability and operations, enabled the nameplate capacity to be upwardly revised from the previously reported capacity of 130,000 bbls/d.

The refinery processes primarily foreign conventional crude oil, with a flexible configuration that allows processing of light, sour and heavy grades of crude oil, as well as intermediate feedstocks. Crude oil is procured from the market on a spot basis or under contracts that can be terminated on short notice. Crude oil for the refinery is largely supplied by the Portland-Montreal Pipeline.

Production yield from the Montreal refinery includes 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. Refined products are delivered to distribution terminals in Ontario via the Trans-Northern Pipeline and delivered to customers directly by truck, rail and marine vessel.

The Sarnia refinery has a crude oil capacity of 85,000 bbls/d, processing both SCO supplied by the company's Oil Sands operations and conventional crude oil purchased from third parties on a spot basis or under contracts that can be terminated on short notice. Crude oil is supplied to the Sarnia refinery primarily via the Enbridge pipelines system. Suncor procures conventional crude oil feedstock primarily from Western Canada, but periodically supplements supply with purchases from the U.S. and other countries. Foreign crude oil is delivered to Sarnia via the Enbridge pipeline system from Montreal.

Production yield from the Sarnia refinery includes gasoline, distillates and petrochemicals, which are primarily distributed in Ontario. Refined products are delivered to distribution terminals in Ontario via the Sun-Canadian Pipeline, or delivered to customers directly via marine vessel and rail. The Sarnia refinery also has limited access to pipelines delivering refined product into the U.S.

To meet the demands of Suncor's marketing network in Eastern North America, the company also imports gasoline and distillates from refiners in Europe. Suncor enters into reciprocal exchange arrangements with other refiners in Eastern North America, primarily for gasoline and distillates, as a means of minimizing transportation costs and balancing product availability. Specialty products, such as asphalts and petrochemicals, are also exported to customers in the U.S.

Suncor holds a 51% interest in ParaChem Chemicals L.P. (ParaChem), which owns and operates a petrochemicals plant located adjacent to the Montreal refinery. Feedstock for the plant includes xylene and toluene produced by the Montreal and Sarnia refineries. The plant primarily produces up to 350,000 metric tons per year of paraxylene, which is used by customers to manufacture polyester textiles and plastic bottles. ParaChem also produces benzene, hydrogen and heavy aromatics. Benzene production is delivered back to the Montreal refinery to be marketed with production from that facility.

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

Western North America

The Edmonton refinery has a crude oil capacity of 135,000 bbls/d and has the potential to run entirely on feedstocks sourced from oil sands and heavy crude oil from Alberta. Feedstock is supplied from Suncor's Oil Sands Base operations, Syncrude operations (including volumes purchased by Suncor from other joint venture owners' share of production) and other producers from the Athabasca and Cold Lake regions of Alberta. The refinery can process directly 35,000 bbls/d of blended feedstock (comprised of 25,000 bbls/d of bitumen and 10,000 bbls/d of diluent) and process 45,000 bbls/d of sour SCO. The refinery can also process 55,000 bbls/d of sweet SCO through its synthetic train. Crude oil is supplied to the refinery via third-party pipelines.

Production yield from the Edmonton refinery includes primarily gasoline and distillates, which are delivered to distribution terminals across Western Canada via the Alberta Products Pipeline, the TransMountain Pipeline and the Enbridge pipeline system, as well as via truck and rail.

Effective January 1, 2012, the Commerce City refinery had a crude oil capacity of 98,000 bbls/d. The observed performance of the refinery, after improvements in reliability and operations, enabled the nameplate capacity to be upwardly revised from the previously reported capacity of 93,000 bbls/d.

The refinery processes primarily conventional crude oil, but also has the capability of processing up to 15,000 bbls/d of sour SCO from Suncor's Oil Sands Base operations. 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. Crude oil purchase contracts have terms ranging from month-to-month to multi-year. Approximately 60% of crude oil supplied to the refinery is transported via pipeline, with the remainder transported via truck.

Production yield from the Commerce City refinery includes primarily gasoline, diesel and asphalt. The majority of the refined products from the refinery are sold to commercial and wholesale customers in Colorado and Wyoming, and a retail network in Colorado. Refined products are distributed by truck, rail, and pipeline.

To support supply and demand balance in the Vancouver area, Suncor imports and exports finished products through its Burrard distribution terminal on the west coast of Canada. Suncor also enters into reciprocal exchange arrangements with other refiners in Western North America as a means of minimizing transportation costs and balancing product availability.

Refinery Throughputs, Utilizations and Yields

The following table summarizes the crude feedstock and utilizations for Suncor's refineries for the years ended December 31, 2011 and 2010. Refinery utilizations for 2011 include the impacts of planned maintenance events at the Sarnia, Edmonton and Commerce City refineries, and the impacts of a month-long disruption to third-party hydrogen supply at Edmonton.

Average Daily Crude Throughput	Montreal		Sarnia		Edmonton		Commerce City	
(mbbls/d, except as noted)	2011	2010	2011	2010	2011	2010	2011	2010
Oil Sands Base sweet synthetic	—	—	11.4	14.1	12.3	11.4	—	0.1
Oil Sands Base sour synthetic	—	—	25.2	17.4	41.2	42.5	7.7	9.4
Other synthetic	—	—	12.6	17.0	41.9	39.6	—	—
East Coast Canada light conventional [(1)]	23.0	41.5	—	—	—	—	—	—
Other light conventional	82.3	54.7	3.2	3.0	—	2.4	67.0	72.0
Sour conventional	10.2	6.4	18.6	19.3	—	—		
Heavy conventional	15.3	19.2	—	—	20.4	22.7	16.0	17.5
Total	130.8	121.8	71.0	70.8	115.8	118.6	90.7	99.0
Utilization [(2)] (%)	101	94	83	83	86	88	98	106

(1) Includes purchases of Suncor and third-party shares of production from East Coast Canada oilfields.

(2) Utilization rates for Montreal and Commerce City are determined based on refinery capacities in effect prior to January 1, 2012.

Refined petroleum production yield mix	Montreal		Sarnia		Edmonton		Commerce City	
(%)	2011	2010	2011	2010	2011	2010	2011	2010
Gasoline	40	42	44	53	46	42	51	51
Distillates	34	32	42	35	50	54	36	36
Other	26	26	14	12	4	4	13	13

Distribution Terminals and Pipelines

Suncor 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.

Suncor has ownership interests in the following pipelines:

Pipeline	Ownership	Type	Origin	Destinations
Portland-Montreal Pipeline	23.8%	Crude oil	Portland, Maine	Montreal, Quebec
Trans-Northern Pipeline	33.3%	Refined product	Montreal, Quebec	Ontario – Ottawa, Toronto, Oakville
Sun-Canadian Pipeline	55.0%	Refined product	Sarnia, Ontario	Ontario – Toronto, London, Hamilton
Alberta Products Pipeline	35.0%	Refined product	Edmonton, Alberta	Calgary, Alberta
Rocky Mountain Crude Pipeline	100.0%	Crude oil	Guernsey, Wyoming	Denver, Colorado
Centennial Pipeline	100.0%	Crude oil	Guernsey, Wyoming	Cheyenne, Colorado

Operations – Marketing

Suncor's retail service station network operates nationally in Canada under the Petro-Canada$_{TM}$ brand. As at December 31, 2011, Suncor's branded retail service station network consisted of 1,465 outlets across Canada. Most of Suncor's owned and operated Sunoco$_{TM}$-branded retail sites were re-branded to the Petro-Canada$_{TM}$ brand in 2010. In addition to marketing through proprietary retail outlets, petroleum product is marketed through independent dealers and joint arrangements. Suncor's network had annual sales of gasoline motor fuels averaging approximately 4.9 million litres per site in 2011 (2010 – 5.1 million litres per site) and attracted an estimated 18% share (2010 – 19% share) of the national retail market (based on data available from Statistics Canada for the period from January to August 2011). The decline in market share in 2011 primarily reflects the loss of volume associated with the disposal of numerous retail sites in 2010 as mandated by the Canadian Competition Bureau as a result of the merger.

Suncor's Colorado retail network consists of 44 owned outlets. Suncor has product supply agreements with an additional 195 Shell®-branded sites and 62 Phillips 66®-branded sites in Colorado.

Marketing activities also generate non-petroleum revenues from convenience stores and car washes.

Suncor's wholesale operations sell petroleum products into farm, home heating, paving, small industrial, commercial and truck markets. Through its PETRO-PASS network, Suncor is the leading national marketer to the commercial road transport segment in Canada. Suncor also sells large volumes of petroleum products directly to large industrial and commercial customers and independent marketers.

The following tables summarize the locations comprising Suncor's retail and wholesale network and the daily sales volumes and corresponding percentages of Refining and Marketing's operating revenues for the years ended December 31, 2011 and 2010.

Locations	As at December 31 2011	2010
Retail Service Stations – Canada		
Petro-Canada$_{TM}$-branded	1 456	1 447
Sunoco$_{TM}$-branded	9	10
	1 465	1 457
Retail Service Stations – Colorado		
Shell®-branded retail service stations	38	37
Phillips 66®-branded retail service stations	6	7
	44	44
Wholesale Cardlock Sites – Canada		
Petro-Canada$_{TM}$-branded cardlock sites (PETRO-PASS)	245	249

Sales Volumes	2011		2010	
	thousands of m^3/d	% operating revenues	thousands of m^3/d	% operating revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	20.9		22.2	
Western North America	18.8		18.9	
	39.7	45	41.1	48
Distillates (includes diesel and heating oils, and aviation jet fuels)				
Eastern North America	12.8		12.4	
Western North America	17.6		18.0	
	30.4	41	30.4	37
Other (includes heavy fuel oil, asphalts, lubricants, petrochemicals, other)				
Eastern North America	9.8		10.7	
Western North America	3.2		5.1	
	13.0	14	15.8	15
	83.1		87.3	

Sales volumes for specific products are somewhat impacted by seasonal cycles: gasoline sales are typically higher during the summer driving season; heating oil sales are typically higher during the winter season; diesel sales are typically higher during the drilling season at the beginning of the year in Western Canada, and during agricultural planting and harvest seasons in early spring and late summer, respectively; and asphalt sales are typically higher during the summer construction paving period. Suncor has the flexibility to modify refinery inputs and outputs to match production yields with anticipated product demands.

Sales volumes can also be impacted when refineries undergo planned maintenance events, which reduce production. Suncor is able to partially mitigate this impact through its integrated facilities: the Edmonton refinery and Oil Sands Base upgrading facilities in Western North America, and the Sarnia and Montreal refineries in Eastern North America. In addition, Suncor may purchase refined products from third-party suppliers.

Other Suncor Businesses

Energy Trading

Suncor's 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.

The Energy Trading business supports the company's Oil Sands production by optimizing price realizations, managing inventory levels during unplanned outages at Suncor's facilities and managing the impacts of external market factors, like pipeline disruptions or outages at refining customers. The Energy Trading business has entered into arrangements for other midstream infrastructure, such as pipeline and storage capacity, to optimize delivery of existing and future growth production, while generating trading earnings on select strategies and opportunities.

The Energy Trading business continues to evaluate additional pipeline agreements to support planned increases in production capacity. Until the company completes its Oil Sands growth projects, Suncor's Energy Trading business expects to optimize the capacities associated with existing arrangements.

Renewable Energy

Suncor's renewable energy interests include a corn-based ethanol facility in southwest Ontario and six wind power projects in operation. Suncor is a Canadian pioneer in wind power with its investments in wind farms, which have a gross generating capacity of 255 MW and reduce carbon dioxide (CO_2) emissions by approximately 470,000 tonnes each year, compared with traditional power generation sources. We continue to evaluate new opportunities to build our renewable energy portfolio, and have a number of potential wind power project sites in various stages of evaluation.

Wind Farm		Ownership Interest (%)	Size (MW)	Turbines	Commissioned
Operated by Suncor					
Wintering Hills	Drumheller, Alberta	70.0	88	55	2011
Kent Breeze	Thamesville, Ontario	100.0	20	8	2011
Non-operated					
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

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 in January 2011. In 2011, the plant produced 381.5 million litres of ethanol (2010 – 206.0 million litres).

SUNCOR EMPLOYEES

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

As of December 31	2011	2010
Oil Sands	5 464	4 753
Exploration and Production	768	898
Refining and Marketing	3 161	3 151
Corporate, Energy Trading and Renewable Energy	3 633	3 274
Total	13 026	12 076

Corporate includes employees from our Major Projects group, which supports the business units. In addition to our employees, the company also uses independent contractors to supply a range of services.

Approximately 36% of the company's employees were covered by collective bargaining agreements at the end of 2011. The Communications, Energy and Paperworkers Union (CEP) represented the majority of the company's unionized employees. A collective agreement with CEP Local 707 representing approximately 3,200 Oil Sands employees is in force and expires in May 2013. Collective agreements that will expire in January 2013 are also in place with the CEP for approximately 1,000 employees in the company's refinery, lubricants, natural gas, and terminal operations. A collective agreement with the CEP representing approximately 65 employees for the Terra Nova facility was renewed in 2011 and will expire in September 2013.

A collective agreement with the United Steel Workers Union representing approximately 260 employees at the Commerce City refinery was recently renewed and will expire in January 2015. An independent union, the Suncor Employee Bargaining Association, represents approximately 200 employees at the Sarnia refinery under an agreement that will expire in May 2012.

SIGNIFICANT POLICIES

Suncor has a Standards of Business Conduct Code (the Code), which applies to Suncor's directors, officers, employees and contractors. The Code requires strict compliance with legal requirements and sets Suncor's standards for the ethical conduct of our business. Topics addressed in the Code include competition, conflict of interest, the protection and proper use of corporate assets and opportunities, confidentiality, disclosure of material information, trading in shares and securities, communications to the public, improper payments, fair dealing in trade relations, and accounting, reporting and business controls. The Code is supported by detailed policy guidance and standards and a Code compliance program, under which every Suncor director, officer, employee and contract worker is required to annually read a summary of the Code and affirm that he or she has reviewed the summary, affirm that he or she understands the requirements of the Code, and provide confirmation of his or her compliance with the Code during the preceding year. Compliance is then reported to the Audit Committee.

Suncor has a Human Rights Policy, which affirms Suncor's responsibility to respect human rights and ensures that Suncor is not complicit in human rights abuses. Suncor is subject to the laws of the countries in which it operates and is committed to complying with all such laws while honouring the spirit of international human rights principles, such as those described in the Universal Declaration of Human Rights and the Voluntary Principles on Security and Human Rights. The policy includes principles committed to a harassment-free and violence-free working environment, which respects the cultures, customs and values of the communities in which we operate. The policy makes it clear that the scope of Suncor's human rights due diligence includes its own operations and, where we can influence our third-party business relationships, the operations of others.

Suncor has 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 an Aboriginal Affairs Policy, which affirms Suncor's desire to work in collaboration with Canada's Aboriginal People 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 People 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 People 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 has an Environment, Health and Safety (EH&S) policy, which affirms Suncor's aspirations to be a sustainable energy company by meeting or exceeding the environmental, social and economic expectations of our current and future stakeholders. The policy reflect Suncor's beliefs that our EH&S efforts are complementary and interdependent with our economic and social performance. The policy makes it clear that Suncor management is responsible for ensuring that employees under their direction are competent to manage their EH&S responsibilities and knowledgeable of the hazards and risks associated with their jobs, and that all Suncor employees and contractors are accountable for compliance with relevant acts, codes, regulations, standards and procedures, and for their own personal safety and the safety of their co-workers.

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 1, 2012, with an effective date of December 31, 2011. The preparation date of the information is as of February 16, 2012.

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).

The reserves data set forth in this section of the AIF for Suncor's Mining (includes Oil Sands Base and Syncrude, unless otherwise noted) and In Situ operations is based upon evaluations conducted by GLJ Petroleum Consultants Ltd. (GLJ) with an effective date of December 31, 2011, contained in their reports (the GLJ Reports). The reserves data set forth below for all other reserves, which includes Suncor's interests in its conventional natural gas assets primarily located in Western Canada (North America Onshore), conventional assets offshore Newfoundland and Labrador (East Coast Canada), conventional assets offshore the U.K. (North Sea), and conventional assets in Syria and Libya (collectively, Other International), is based upon evaluations conducted by Sproule Associates Limited or Sproule International Limited (collectively, Sproule) with an effective date of

December 31, 2011 contained in their reports (the Sproule Reports). Each of GLJ and Sproule (collectively, the Evaluators) are independent qualified reserves evaluators as defined in NI 51-101. All factual data supplied to the Evaluators was accepted as presented. For general interest purposes, GLJ conducted field tours of Suncor's Millennium mine and the Syncrude Aurora North mine. No other field inspections were deemed necessary by the Evaluators.

The reserves data summarizes Suncor's SCO, bitumen, light and medium oil, NGL 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, and general and administrative expenses. Net present values of future revenues include the impact of certain abandonment costs. For more information on abandonment costs, see the Future Net Revenues Tables and Notes – Abandonment and Reclamation Costs section of this AIF.

Future net revenues are presented on before-tax and after-tax bases. The reserves data conforms to the requirements of NI 51-101. See also the Notes to Reserves Data Tables and the Definitions for Reserves Data Tables discussions presented subsequently in this section of the AIF.

Advisories – Future Net Revenues

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. There is no guarantee that the estimates for SCO, bitumen, light and medium oil, NGL and natural gas reserves provided herein will be recovered. Actual SCO, bitumen, light and medium oil, NGL and natural gas reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in the Notes to Reserves Data Tables, Definitions for Reserves Data Tables and Notes to Future Net Revenues Tables discussions in conjunction with the following notes and tables.

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 as a result of newly acquired technical data, technology improvements, or changes in historical performance, pricing, economic conditions, market availability, and regulatory requirements. Additional technical information regarding geology, reservoir properties, reservoir fluid properties and well performance are obtained through seismic programs, drilling programs, updated reservoir performance studies and analysis, 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. Depending on the current business environment, higher commodity prices may result in higher reserves by making more projects economically viable and extending their economic life, while lower commodity prices may result in lower reserves, although this generally does not result for assets under Production Sharing Contracts. 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.

In 2011, the company's assets in Syria were impacted by political unrest. As a result of the current situation in Syria, reserves previously reported as proved developed producing and probable developed producing have been reclassified to the respective non-producing categories. In addition, estimated 2012 production from Syria has not been included as reserves, but has been reflected as contingent resources, as current sanctions prohibit Suncor from receiving payment for any production that may occur during the force majeure period.

For more information as to the risks involved when estimating reserves and resources, see the Risk Factors – Uncertainty of Reserves and Resources Estimates section in this AIF.

Disclosure of Resources Data

GLJ conducted an independent evaluation of Best Estimate contingent resources volumes for all of Suncor's Mining properties and for Suncor's In Situ properties for which they also evaluated reserves. For Suncor's In Situ properties without attributed reserves, GLJ audited Suncor's internal evaluation of Best Estimate contingent resources volumes. Best Estimate contingent resources for conventional properties were prepared by Suncor's qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation (COGE) Handbook. For more information on contingent resources, see the discussion in the Additional Information Relating to Reserves Data – Contingent Resources section of this AIF.

Oil and Gas Reserves Tables and Notes

Summary of Oil and Gas Reserves [(1)(2)(3)]
as at December 31, 2011
(forecast prices and costs)

	SCO		Bitumen		Light & Medium Oil		Natural Gas		NGLs		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcf	bcf	mmbbls	mmbbls	mmboe	mmboe
Proved Developed Producing												
Mining	2 022.5	1 722.1	—	—	—	—	—	—	—	—	2 022.5	1 722.1
In Situ	203.0	191.0	47.7	39.4	—	—	—	—	—	—	250.7	230.4
East Coast Canada	—	—	—	—	48.1	38.2	—	—	—	—	48.1	38.2
North America Onshore	—	—	—	—	11.2	9.2	805.7	688.8	6.3	4.6	151.7	128.6
Total Canada	2 225.5	1 913.1	47.7	39.4	59.3	47.4	805.7	688.8	6.3	4.6	2 473.0	2 119.3
North Sea	—	—	—	—	71.5	71.5	3.3	3.3	0.3	0.3	72.3	72.3
Other International	—	—	—	—	96.0	35.7	—	—	—	—	96.0	35.7
Total Proved Developed Producing	**2 225.5**	**1 913.1**	**47.7**	**39.4**	**226.8**	**154.6**	**809.0**	**692.1**	**6.6**	**4.9**	**2 641.3**	**2 227.3**
Proved Developed Non-Producing												
Mining	—	—	—	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—	—	—	—
North America Onshore	—	—	—	—	0.1	0.1	40.5	31.3	0.2	0.1	7.0	5.4
Total Canada	—	—	—	—	0.1	0.1	40.5	31.3	0.2	0.1	7.0	5.4
North Sea	—	—	—	—	21.4	21.4	1.1	1.1	0.1	0.1	21.6	21.6
Other International	—	—	—	—	36.6	14.3	334.5	206.9	11.9	7.0	104.2	55.8
Total Proved Developed Non-Producing	**—**	**—**	**—**	**—**	**58.1**	**35.8**	**376.1**	**239.3**	**12.2**	**7.2**	**132.8**	**82.8**
Proved Undeveloped												
Mining	—	—	—	—	—	—	—	—	—	—	—	—
In Situ	502.0	430.0	661.1	572.4	—	—	—	—	—	—	1 163.1	1 002.4
East Coast Canada	—	—	—	—	26.6	20.7	—	—	—	—	26.6	20.7
North America Onshore	—	—	—	—	0.3	0.3	78.7	72.8	0.1	—	13.5	12.4
Total Canada	502.0	430.0	661.1	572.4	26.9	21.0	78.7	72.8	0.1	—	1 203.2	1 035.5
North Sea	—	—	—	—	43.3	43.3	2.7	2.7	0.1	0.1	43.8	43.8
Other International	—	—	—	—	5.8	2.4	—	—	—	—	5.8	2.4
Total Proved Undeveloped	**502.0**	**430.0**	**661.1**	**572.4**	**76.0**	**66.7**	**81.4**	**75.5**	**0.2**	**0.1**	**1 252.8**	**1 081.7**
Proved												
Mining	2 022.5	1 722.1	—	—	—	—	—	—	—	—	2 022.5	1 722.1
In Situ	705.0	621.0	708.8	611.8	—	—	—	—	—	—	1 413.8	1 232.8
East Coast Canada	—	—	—	—	74.7	58.9	—	—	—	—	74.7	58.9
North America Onshore	—	—	—	—	11.5	9.6	924.9	792.9	6.6	4.7	172.3	146.4
Total Canada	2 727.5	2 343.1	708.8	611.8	86.2	68.5	924.9	792.9	6.6	4.7	3 683.3	3 160.2
North Sea	—	—	—	—	136.2	136.2	7.1	7.1	0.5	0.5	137.9	137.9
Other International	—	—	—	—	138.4	52.4	334.5	207.1	11.9	7.0	206.1	93.9
Total Proved	**2 727.5**	**2 343.1**	**708.8**	**611.8**	**360.8**	**257.1**	**1 266.5**	**1 007.1**	**19.0**	**12.2**	**4 027.3**	**3 392.0**
Probable												
Mining	552.7	478.4	—	—	—	—	—	—	—	—	552.7	478.4
In Situ	1 271.9	1 061.2	693.9	552.0	—	—	—	—	—	—	1 965.8	1 613.2
East Coast Canada	—	—	—	—	275.3	201.0	—	—	—	—	275.3	201.0
North America Onshore	—	—	—	—	5.0	4.1	320.4	262.8	2.9	2.1	61.3	50.0
Total Canada	1 824.6	1 539.6	693.9	552.0	280.3	205.1	320.4	262.8	2.9	2.1	2 855.1	2 342.6
North Sea	—	—	—	—	36.1	36.1	2.9	2.9	0.1	0.1	36.7	36.7
Other International	—	—	—	—	104.9	40.3	405.5	168.8	14.5	7.0	187.0	75.4
Total Probable	**1 824.6**	**1 539.6**	**693.9**	**552.0**	**421.3**	**281.5**	**728.8**	**434.5**	**17.5**	**9.2**	**3 078.8**	**2 454.7**
Proved Plus Probable												
Mining	2 575.2	2 200.5	—	—	—	—	—	—	—	—	2 575.2	2 200.5
In Situ	1 976.9	1 682.2	1 402.7	1 163.8	—	—	—	—	—	—	3 379.6	2 846.0
East Coast Canada	—	—	—	—	350.0	259.9	—	—	—	—	350.0	259.9
North America Onshore	—	—	—	—	16.5	13.7	1 245.3	1 055.7	9.5	6.8	233.6	196.5
Total Canada	4 552.1	3 882.7	1 402.7	1 163.8	366.5	273.6	1 245.3	1 055.7	9.5	6.8	6 538.4	5 502.9
North Sea	—	—	—	—	172.3	172.3	10.0	10.0	0.6	0.6	174.5	174.5
Other International	—	—	—	—	243.3	92.7	740.0	375.9	26.4	14.0	393.0	169.3
Total Proved Plus Probable	**4 552.1**	**3 882.7**	**1 402.7**	**1 163.8**	**782.1**	**538.6**	**1 995.3**	**1 441.6**	**36.5**	**21.4**	**7 105.9**	**5 846.7**

Please see Notes (1) through (3) 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, 2011
(constant prices and costs)

	SCO		Bitumen		Light & Medium Oil		Natural Gas		NGLs		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcf	bcf	mmbbls	mmbbls	mmboe	mmboe
Proved Developed Producing												
Mining	2 022.5	1 718.2	—	—	—	—	—	—	—	—	2 022.5	1 718.2
In Situ	202.9	194.0	47.7	40.2	—	—	—	—	—	—	250.6	234.2
East Coast Canada	—	—	—	—	48.1	37.2	—	—	—	—	48.1	37.2
North America Onshore	—	—	—	—	11.2	9.6	731.8	640.1	6.1	4.4	139.2	120.7
Total Canada	2 225.4	1 912.2	47.7	40.2	59.3	46.8	731.8	640.1	6.1	4.4	2 460.4	2 110.3
North Sea	—	—	—	—	71.7	71.7	3.3	3.3	0.3	0.3	72.5	72.5
Other International	—	—	—	—	96.3	36.4	—	—	—	—	96.3	36.4
Total Proved Developed Producing	**2 225.4**	**1 912.2**	**47.7**	**40.2**	**227.3**	**154.9**	**735.1**	**643.4**	**6.4**	**4.7**	**2 629.2**	**2 219.2**
Proved Developed Non-Producing												
Mining	—	—	—	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—	—	—	—
North America Onshore	—	—	—	—	0.1	0.1	18.3	14.7	0.2	0.1	3.3	2.6
Total Canada	—	—	—	—	0.1	0.1	18.3	14.7	0.2	0.1	3.3	2.6
North Sea	—	—	—	—	21.7	21.7	1.1	1.1	0.1	0.1	22.0	22.0
Other International	—	—	—	—	36.7	14.3	338.6	199.0	12.0	6.7	105.1	54.2
Total Proved Developed Non-Producing	**—**	**—**	**—**	**—**	**58.5**	**36.1**	**358.0**	**214.8**	**12.3**	**6.9**	**130.4**	**78.8**
Proved Undeveloped												
Mining	—	—	—	—	—	—	—	—	—	—	—	—
In Situ	502.0	446.5	661.1	584.0	—	—	—	—	—	—	1 163.1	1 030.5
East Coast Canada	—	—	—	—	26.6	20.2	—	—	—	—	26.6	20.2
North America Onshore	—	—	—	—	0.3	0.3	11.5	10.5	—	—	2.2	2.1
Total Canada	502.0	446.5	661.1	584.0	26.9	20.5	11.5	10.5	—	—	1 191.9	1 052.8
North Sea	—	—	—	—	43.9	43.9	2.7	2.7	0.1	0.1	44.4	44.4
Other International	—	—	—	—	5.8	2.4	—	—	—	—	5.8	2.4
Total Proved Undeveloped	**502.0**	**446.5**	**661.1**	**584.0**	**76.6**	**66.8**	**14.2**	**13.2**	**0.1**	**0.1**	**1 242.1**	**1 099.6**
Proved												
Mining	2 022.5	1 718.2	—	—	—	—	—	—	—	—	2 022.5	1 718.2
In Situ	704.9	640.5	708.8	624.2	—	—	—	—	—	—	1 413.7	1 264.7
East Coast Canada	—	—	—	—	74.7	57.4	—	—	—	—	74.7	57.4
North America Onshore	—	—	—	—	11.5	10.0	761.6	665.3	6.3	4.5	144.7	125.4
Total Canada	2 727.4	2 358.7	708.8	624.2	86.2	67.4	761.6	665.3	6.3	4.5	3 655.6	3 165.7
North Sea	—	—	—	—	137.3	137.3	7.1	7.1	0.5	0.5	138.9	138.9
Other International	—	—	—	—	138.8	53.1	338.6	199.0	12.0	6.7	207.3	93.0
Total Proved	**2 727.4**	**2 358.7**	**708.8**	**624.2**	**362.3**	**257.8**	**1 107.3**	**871.4**	**18.8**	**11.7**	**4 001.8**	**3 397.6**
Probable												
Mining	552.7	480.0	—	—	—	—	—	—	—	—	552.7	480.0
In Situ	1 271.9	1 114.5	693.9	566.0	—	—	—	—	—	—	1 965.8	1 680.5
East Coast Canada	—	—	—	—	275.3	197.1	—	—	—	—	275.3	197.1
North America Onshore	—	—	—	—	5.0	4.3	227.4	197.1	2.3	1.6	45.2	38.8
Total Canada	1 824.6	1 594.5	693.9	566.0	280.3	201.4	227.4	197.1	2.3	1.6	2 839.0	2 396.4
North Sea	—	—	—	—	35.6	35.6	2.9	2.9	0.1	0.1	36.2	36.2
Other International	—	—	—	—	104.5	37.7	401.4	157.0	14.4	6.6	185.8	70.5
Total Probable	**1 824.6**	**1 594.5**	**693.9**	**566.0**	**420.4**	**274.7**	**631.7**	**357.0**	**16.8**	**8.3**	**3 061.0**	**2 503.1**
Proved Plus Probable												
Mining	2 575.2	2 198.2	—	—	—	—	—	—	—	—	2 575.2	2 198.2
In Situ	1 976.8	1 755.0	1 402.7	1 190.2	—	—	—	—	—	—	3 379.5	2 945.2
East Coast Canada	—	—	—	—	350.0	254.5	—	—	—	—	350.0	254.5
North America Onshore	—	—	—	—	16.5	14.3	989.0	862.4	8.6	6.1	189.9	164.2
Total Canada	4 552.0	3 953.2	1 402.7	1 190.2	366.5	268.8	989.0	862.4	8.6	6.1	6 494.6	5 562.1
North Sea	—	—	—	—	172.9	172.9	10.0	10.0	0.6	0.6	175.1	175.1
Other International	—	—	—	—	243.3	90.8	740.0	356.0	26.4	13.3	393.1	163.5
Total Proved Plus Probable	**4 552.0**	**3 953.2**	**1 402.7**	**1 190.2**	**782.7**	**532.5**	**1 739.0**	**1 228.4**	**35.6**	**20.0**	**7 062.8**	**5 900.7**

Please see Notes (1) through (3) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Oil Reserves [1][2][3]

as at December 31, 2011
(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, 2010									
Mining	2 084.3	541.5	2 625.8	—	36.7	36.7	—	—	—
In Situ	821.6	461.5	1 283.1	397.3	1 849.9	2 247.2	—	—	—
East Coast Canada	—	—	—	—	—	—	80.8	148.7	229.5
North America Onshore	—	—	—	—	—	—	10.5	6.5	17.0
Total Canada	2 905.9	1 003.0	3 908.9	397.3	1 886.6	2 283.9	91.3	155.2	246.5
North Sea	—	—	—	—	—	—	117.9	57.4	175.3
Other International	—	—	—	—	—	—	140.5	100.7	241.2
Total	**2 905.9**	**1 003.0**	**3 908.9**	**397.3**	**1 886.6**	**2 283.9**	**349.7**	**313.3**	**663.0**
Extensions & Improved Recovery [4]									
Mining	—	—	—	—	—	—	—	—	—
In Situ	93.8	(93.8)	—	87.1	(87.1)	—	—	—	—
East Coast Canada	—	—	—	—	—	—	2.2	143.7	145.9
North America Onshore	—	—	—	—	—	—	1.3	(0.4)	0.9
Total Canada	93.8	(93.8)	—	87.1	(87.1)	—	3.5	143.3	146.8
North Sea	—	—	—	—	—	—	—	—	—
Other International	—	—	—	—	—	—	1.2	1.5	2.7
Total	**93.8**	**(93.8)**	**—**	**87.1**	**(87.1)**	**—**	**4.7**	**144.8**	**149.5**
Technical Revisions [5]									
Mining	33.8	11.2	45.0	—	(36.7)	(36.7)	—	—	—
In Situ [8]	(191.3)	904.2	712.9	233.2	(1068.9)	(835.7)	—	—	—
East Coast Canada	—	—	—	—	—	—	15.7	(17.1)	(1.4)
North America Onshore	—	—	—	—	—	—	0.6	(1.1)	(0.5)
Total Canada	(157.5)	915.4	757.9	233.2	(1105.6)	(872.4)	16.3	(18.2)	(1.9)
North Sea	—	—	—	—	—	—	26.3	(25.8)	0.5
Other International	—	—	—	—	—	—	1.8	2.8	4.6
Total	**(157.5)**	**915.4**	**757.9**	**233.2**	**(1105.6)**	**(872.4)**	**44.4**	**(41.2)**	**3.2**
Discoveries [6]									
Mining	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—
North America Onshore	—	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	—	—
North Sea	—	—	—	—	—	—	24.6	13.8	38.4
Other International	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**24.6**	**13.8**	**38.4**

Please see Notes (1) through (8) 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, 2011
(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	—	—	—	—	—	—	—	—	—
North America Onshore	—	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	—	—
North Sea	—	—	—	—	—	—	—	—	—
Other International	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Dispositions									
Mining	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—
North America Onshore	—	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	—	—
North Sea	—	—	—	—	—	—	(15.7)	(9.4)	(25.1)
Other International	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**(15.7)**	**(9.4)**	**(25.1)**
Economic Factors [7]									
Mining	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—
North America Onshore	—	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	—	—
North Sea	—	—	—	—	—	—	—	—	—
Other International	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Production									
Mining	(95.6)	—	(95.6)	—	—	—	—	—	—
In Situ	(19.2)	—	(19.2)	(8.8)	—	(8.8)	—	—	—
East Coast Canada	—	—	—	—	—	—	(24.0)	—	(24.0)
North America Onshore	—	—	—	—	—	—	(0.9)	—	(0.9)
Total Canada	(114.8)	—	(114.8)	(8.8)	—	(8.8)	(24.9)	—	(24.9)
North Sea	—	—	—	—	—	—	(16.9)	—	(16.9)
Other International	—	—	—	—	—	—	(5.1)	—	(5.1)
Total	**(114.8)**	**—**	**(114.8)**	**(8.8)**	**—**	**(8.8)**	**(46.9)**	**—**	**(46.9)**
December 31, 2011									
Mining	2 022.5	552.7	2 575.2	—	—	—	—	—	—
In Situ	704.9	1 271.9	1 976.8	708.8	693.9	1 402.7	—	—	—
East Coast Canada	—	—	—	—	—	—	74.7	275.3	350.0
North America Onshore	—	—	—	—	—	—	11.5	5.0	16.5
Total Canada	2 727.4	1 824.6	4 552.0	708.8	693.9	1 402.7	86.2	280.3	366.5
North Sea	—	—	—	—	—	—	136.2	36.0	172.2
Other International	—	—	—	—	—	—	138.4	105.0	243.4
Total	**2 727.4**	**1 824.6**	**4 552.0**	**708.8**	**693.9**	**1 402.7**	**360.8**	**421.3**	**782.1**

Please see Notes (1) through (8) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Natural Gas and NGL Reserves [1][2][3]

as at December 31, 2011
(forecast prices and costs)

	Natural Gas			NGLs		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	bcf	bcf	bcf	mmbbls	mmbbls	mmbbls
December 31, 2010						
Canada – North America Onshore	1 113.2	373.9	1 487.1	8.0	3.4	11.4
North Sea	11.5	4.4	15.9	0.8	0.3	1.1
Other International	251.1	281.1	532.2	7.9	9.2	17.1
Total	**1 375.8**	**659.4**	**2 035.2**	**16.7**	**12.9**	**29.6**
Extensions & Improved Recovery [4]						
Canada – North America Onshore	5.1	11.1	16.2	0.1	—	0.1
North Sea	—	—	—	—	—	—
Other International	—	—	—	—	—	—
Total	**5.1**	**11.1**	**16.2**	**0.1**	**—**	**0.1**
Technical Revisions [5]						
Canada – North America Onshore	41.4	(1.0)	40.4	0.2	(0.3)	(0.1)
North Sea	(0.1)	(2.3)	(2.4)	—	(0.2)	(0.2)
Other International	114.7	125.3	240.0	5.4	5.3	10.7
Total	**156.0**	**122.0**	**278.0**	**5.6**	**4.8**	**10.4**
Discoveries [6]						
Canada – North America Onshore	—	—	—	—	—	—
North Sea	1.5	1.2	2.7	—	—	—
Other International	—	—	—	—	—	—
Total	**1.5**	**1.2**	**2.7**	**—**	**—**	**—**
Acquisitions						
Canada – North America Onshore	0.2	—	0.2	—	—	—
North Sea	—	—	—	—	—	—
Other International	—	—	—	—	—	—
Total	**0.2**	**—**	**0.2**	**—**	**—**	**—**
Dispositions						
Canada – North America Onshore	(55.6)	(31.5)	(87.1)	(0.6)	(0.2)	(0.8)
North Sea	(4.0)	(0.4)	(4.4)	(0.2)	—	(0.2)
Other International	—	—	—	—	—	—
Total	**(59.6)**	**(31.9)**	**(91.5)**	**(0.8)**	**(0.2)**	**(1.0)**
Economic Factors [7]						
Canada – North America Onshore	(52.2)	(32.1)	(84.3)	(0.1)	—	(0.1)
North Sea	—	—	—	—	—	—
Other International	(2.1)	(0.9)	(3.0)	(0.1)	—	(0.1)
Total	**(54.3)**	**(33.0)**	**(87.3)**	**(0.2)**	**—**	**(0.2)**
Production						
Canada – North America Onshore	(127.2)	—	(127.2)	(1.0)	—	(1.0)
North Sea	(1.8)	—	(1.8)	(0.1)	—	(0.1)
Other International	(29.2)	—	(29.2)	(1.3)	—	(1.3)
Total	**(158.2)**	**—**	**(158.2)**	**(2.4)**	**—**	**(2.4)**
December 31, 2011						

Canada – North America Onshore	924.9	320.4	1 245.3	6.6	2.9	9.5
North Sea	7.1	2.9	10.0	0.5	0.1	0.6
Other International	334.5	405.5	740.0	11.9	14.5	26.4
Total	**1 266.5**	**728.8**	**1 995.3**	**19.0**	**17.5**	**36.5**

Please see Notes (1) through (8) 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, 2011

(1) The reserves data is based upon evaluations by the Evaluators with an effective date of December 31, 2011.

(2) See the Notes to Future Net Revenues Tables discussion for information on forecast and constant prices and costs.

(3) Other International reserves, which include Libya and Syria, include quantities of crude oil and natural gas, which are expected to 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 the Definitions for Reserves Data Tables.

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

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

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

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

(8) Technical revisions for In Situ probable reserves included a large increase in SCO probable reserves and a large decrease in bitumen probable reserves due to the inclusion of an assumption that the company's upgrading capacity will require significantly more bitumen from In Situ assets when Mining reserves are eventually depleted.

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 a working 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, NGL and natural gas reserves estimates presented are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is 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 (i) 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, or (ii) through installed extraction equipment and infrastructure that is operational at the time of the reserves estimate, if the extraction is by means not involving a well. The developed category may be subdivided into producing and non-producing.

(a) 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.

(b) 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 evaluator'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% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50% 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.

Future Net Revenues Tables and Notes

Net Present Value of Future Net Revenues Before Income Taxes

as at December 31, 2011
(forecast prices and costs)

	(in $ millions, discounted at % per year)					Unit Value [1]
	0%	5%	10%	15%	20%	$/boe
Proved Developed Producing						
Mining	65 036	40 083	27 354	20 207	15 843	15.88
In Situ	7 694	6 467	5 546	4 835	4 275	24.06
East Coast Canada	1 959	1 774	1 617	1 487	1 381	42.38
North America Onshore	3 026	2 136	1 657	1 361	1 158	12.89
Total Canada	77 715	50 460	36 174	27 890	22 657	17.07
North Sea	6 469	5 636	5 016	4 542	4 167	69.33
Other International	3 235	2 368	1 862	1 534	1 306	52.12
Total Proved Developed Producing	87 419	58 464	43 052	33 966	28 130	19.33
Proved Developed Non-Producing						
Mining	—	—	—	—	—	—
In Situ	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—
North America Onshore	65	46	34	26	19	6.34
Total Canada	65	46	34	26	19	6.34
North Sea	1 707	1 293	1 033	858	735	47.76
Other International	3 797	2 783	2 145	1 718	1 416	38.46
Total Proved Developed Non-Producing	5 569	4 122	3 212	2 602	2 170	38.80
Proved Undeveloped						
Mining	—	—	—	—	—	—
In Situ	23 112	10 338	4 649	1 928	543	4.64
East Coast Canada	1 070	742	542	410	316	26.15
North America Onshore	167	92	49	22	7	3.91
Total Canada	24 349	11 172	5 240	2 360	866	5.06
North Sea	2 629	1 860	1 338	972	706	30.55
Other International	135	91	62	43	29	25.88
Total Proved Undeveloped	27 113	13 123	6 640	3 375	1 601	6.14
Proved						
Mining	65 036	40 083	27 354	20 207	15 843	15.88
In Situ	30 806	16 805	10 195	6 763	4 819	8.27
East Coast Canada	3 029	2 516	2 159	1 897	1 696	36.67
North America Onshore	3 258	2 274	1 740	1 409	1 184	11.88
Total Canada	102 129	61 678	41 448	30 276	23 542	13.11
North Sea	10 805	8 789	7 387	6 372	5 608	53.61
Other International	7 167	5 242	4 069	3 295	2 751	43.33
Total Proved	120 101	75 709	52 904	39 943	31 901	15.60
Probable						
Mining	28 852	9 564	4 403	2 563	1 755	9.21
In Situ	70 038	19 720	7 052	3 055	1 503	4.37
East Coast Canada	15 139	8 910	5 745	3 957	2 867	28.58
North America Onshore	1 350	666	386	245	165	7.65
Total Canada	115 379	38 860	17 586	9 820	6 290	7.51
North Sea	3 347	2 265	1 639	1 247	987	44.67
Other International	6 257	3 468	2 126	1 406	983	28.19
Total Probable	124 983	44 593	21 351	12 473	8 260	8.70
Proved Plus Probable						
Mining	93 888	49 647	31 757	22 770	17 598	14.43
In Situ	100 844	36 525	17 247	9 818	6 322	6.06
East Coast Canada	18 168	11 426	7 904	5 854	4 563	30.41
North America Onshore	4 608	2 940	2 126	1 654	1 349	10.80
Total Canada	217 508	100 538	59 034	40 096	29 832	10.73
North Sea	14 152	11 054	9 026	7 619	6 595	51.73
Other International	13 424	8 710	6 195	4 701	3 734	36.59
Total Proved Plus Probable	245 084	120 302	74 255	52 416	40 161	12.70

(1) Unit values are future net revenues before income taxes, discounted at 10%, using net reserves.

Net Present Value of Future Net Revenues After Income Taxes

as at December 31, 2011
(forecast prices and costs)

	(in $ millions, discounted at % per year)				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	49 438	30 108	20 375	14 962	11 681
In Situ	6 845	5 746	4 925	4 295	3 801
East Coast Canada	1 486	1 377	1 243	1 138	1 052
North America Onshore	2 470	1 754	1 369	1 128	963
Total Canada	60 239	38 985	27 912	21 523	17 497
North Sea	2 086	1 850	1 663	1 515	1 397
Other International	1 132	842	671	561	483
Total Proved Developed Producing	63 457	41 677	30 246	23 599	19 377
Proved Developed Non-Producing					
Mining	—	—	—	—	—
In Situ	—	—	—	—	—
East Coast Canada	—	—	—	—	—
North America Onshore	48	33	23	16	12
Total Canada	48	33	23	16	12
North Sea	659	506	411	348	303
Other International	2 360	1 775	1 396	1 135	947
Total Proved Developed Non-Producing	3 067	2 314	1 830	1 499	1 262
Proved Undeveloped					
Mining	—	—	—	—	—
In Situ	16 996	7 154	2 851	839	(156)
East Coast Canada	790	515	376	279	208
North America Onshore	124	63	28	8	(4)
Total Canada	17 910	7 732	3 255	1 126	48
North Sea	1 010	731	537	397	293
Other International	58	40	28	19	13
Total Proved Undeveloped	18 978	8 503	3 820	1 542	354
Proved					
Mining	49 438	30 108	20 375	14 962	11 681
In Situ	23 841	12 900	7 776	5 134	3 645
East Coast Canada	2 276	1 892	1 619	1 417	1 260
North America Onshore	2 642	1 850	1 420	1 152	971
Total Canada	78 197	46 750	31 190	22 665	17 557
North Sea	3 755	3 087	2 611	2 260	1 993
Other International	3 550	2 657	2 095	1 715	1 443
Total Proved	85 502	52 494	35 896	26 640	20 993
Probable					
Mining	22 121	7 194	3 232	1 843	1 246
In Situ	51 925	14 182	4 837	1 932	823
East Coast Canada	11 081	6 063	3 932	2 676	1 893
North America Onshore	1 007	493	280	173	113
Total Canada	86 134	27 932	12 281	6 624	4 075
North Sea	1 284	885	651	504	405
Other International	2 911	1 566	934	601	410
Total Probable	90 329	30 383	13 866	7 729	4 890
Proved Plus Probable					
Mining	71 559	37 302	23 607	16 805	12 927
In Situ	75 766	27 082	12 613	7 066	4 468
East Coast Canada	13 357	7 955	5 551	4 093	3 153
North America Onshore	3 649	2 343	1 700	1 325	1 084
Total Canada	164 331	74 682	43 471	29 289	21 632
North Sea	5 039	3 972	3 262	2 764	2 398
Other International	6 461	4 223	3 029	2 316	1 853
Total Proved Plus Probable	175 831	82 877	49 762	34 369	25 883

Total Future Net Revenues
as at December 31, 2011
(forecast prices and costs)

(in $ millions, undiscounted)	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Expenses	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	223 537	33 649	88 270	36 582	—	65 036	15 598	49 438
In Situ	23 124	1 701	10 809	2 843	77	7 694	849	6 845
East Coast Canada	5 009	1 038	1 305	448	259	1 959	473	1 486
North America Onshore	6 719	897	2 639	14	143	3 026	556	2 470
Total Canada	258 389	37 285	103 023	39 887	479	77 715	17 476	60 239
North Sea	7 550	—	935	66	80	6 469	4 383	2 086
Other International	3 868	—	441	180	12	3 235	2 103	1 132
Total Proved Developed Producing	269 807	37 285	104 399	40 133	571	87 419	23 962	63 457
Proved Developed Non-Producing								
Mining	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—
North America Onshore	237	42	107	21	2	65	17	48
Total Canada	237	42	107	21	2	65	17	48
North Sea	2 342	—	629	—	6	1 707	1 048	659
Other International	5 835	749	1 205	80	4	3 797	1 437	2 360
Total Proved Developed Non-Producing	8 414	791	1 941	101	12	5 569	2 502	3 067
Proved Undeveloped								
Mining	—	—	—	—	—	—	—	—
In Situ	108 481	15 527	41 702	27 597	543	23 112	6 116	16 996
East Coast Canada	2 833	624	604	506	29	1 070	280	790
North America Onshore	515	36	127	168	17	167	43	124
Total Canada	111 829	16 187	42 433	28 271	589	24 349	6 439	17 910
North Sea	4 585	—	960	959	37	2 629	1 619	1 010
Other International	277	24	54	63	1	135	77	58
Total Proved Undeveloped	116 691	16 211	43 447	29 293	627	27 113	8 135	18 978
Proved								
Mining	223 537	33 649	88 270	36 582	—	65 036	15 598	49 438
In Situ	131 605	17 228	52 511	30 440	620	30 806	6 965	23 841
East Coast Canada	7 842	1 662	1 909	954	288	3 029	753	2 276
North America Onshore	7 471	975	2 873	203	162	3 258	616	2 642
Total Canada	370 455	53 514	145 563	68 179	1 070	102 129	23 932	78 197
North Sea	14 477	—	2 524	1 025	123	10 805	7 050	3 755
Other International	9 980	773	1 700	323	17	7 167	3 617	3 550
Total Proved	394 912	54 287	149 787	69 527	1 210	120 101	34 599	85 502
Probable								
Mining	80 974	11 289	29 877	10 956	—	28 852	6 731	22 121
In Situ	259 749	46 872	90 543	51 537	759	70 038	18 113	51 925
East Coast Canada	29 175	7 906	3 349	2 632	149	15 139	4 058	11 081
North America Onshore	3 377	498	1 329	177	23	1 350	343	1 007
Total Canada	373 275	66 565	125 098	65 302	931	115 379	29 245	86 134
North Sea	4 047	—	597	86	17	3 347	2 063	1 284
Other International	9 167	1 113	1 313	481	3	6 257	3 346	2 911
Total Probable	386 489	67 678	127 008	65 869	951	124 983	34 654	90 329
Proved Plus Probable								
Mining	304 511	44 938	118 147	47 538	—	93 888	22 329	71 559
In Situ	391 354	64 100	143 054	81 977	1 379	100 844	25 078	75 766
East Coast Canada	37 017	9 568	5 258	3 586	437	18 168	4 811	13 357
North America Onshore	10 848	1 473	4 202	380	185	4 608	959	3 649
Total Canada	743 730	120 079	270 661	133 481	2 001	217 508	53 177	164 331
North Sea	18 524	—	3 121	1 111	140	14 152	9 113	5 039
Other International	19 147	1 886	3 013	804	20	13 424	6 963	6 461
Total Proved Plus Probable	781 401	121 965	276 795	135 396	2 161	245 084	69 253	175 831

Future Net Revenues by Production Group
as at December 31, 2011
(forecast prices and costs)

(before income taxes, discounted at 10% per year)

	$ millions	$/boe [1]
Proved Producing		
Unconventional – Mining	27 354	15.88
Unconventional – In Situ	5 546	24.06
Total Unconventional [2]	32 900	16.85
Light & Medium Oil [3]	8 822	56.02
Natural Gas [4]	1 330	11.34
Total Proved Producing	43 052	19.33
Proved		
Unconventional – Mining	27 354	15.88
Unconventional – In Situ	10 195	8.27
Total Unconventional [2]	37 549	12.71
Light & Medium Oil [3]	12 466	47.95
Natural Gas [4]	2 889	16.32
Total Proved	52 904	15.60
Proved Plus Probable		
Unconventional – Mining	31 757	14.43
Unconventional – In Situ	17 247	6.06
Total Unconventional [2]	49 004	9.71
Light & Medium Oil [3]	21 432	39.48
Natural Gas [4]	3 819	14.82
Total Proved Plus Probable	74 255	12.70

(1) Per unit values use net reserves.

(2) Total Unconventional includes SCO and bitumen.

(3) Light & Medium Oil includes associated byproducts, including solution gas and NGLs.

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

Notes to Future Net Revenues Tables

Prices Realized

For prices realized by Suncor during 2011, please see the Production History section contained within this Statement of Reserves Data and Other Oil and Gas Information.

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, 2012, 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 included a US$/Cdn$ exchange rate of 0.98, a Cdn$/€ exchange rate of 1.35 and a Cdn$/£ exchange rate of 1.60. Forecast costs included a 2% inflation factor, except for costs for Mining, which included 4% inflation for 2013-2015, 3% inflation for 2016 and 2% thereafter.

Constant Prices and Costs

For purposes of comparison to those issuers who are required to report reserves estimates using constant prices and costs in accordance with the rules and regulations of the U.S. Securities and Exchange Commission (SEC), Suncor also presents reserves estimates using 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 arithmetic average of the first-day-of-the-month price for the product for each month of 2011.

Constant prices included a US$/Cdn$ exchange rate of 1.02, a Cdn$/€ exchange rate of 1.38 and a Cdn$/£ exchange rate of 1.58.

Prices used in Reserves Tables (1)

Forecast	WTI (2)	WCS (3)	Pentanes (4)	AECO (5)	Light Sweet (6)	Brent (7)	NBP (8)	B.C. Gas (9)
Year	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/bbl	US$/bbl	Cdn$/mmbtu	Cdn$/mmbtu
2012	97.00	81.61	107.76	3.49	97.96	105.00	9.32	3.29
2013	100.00	82.63	108.09	4.13	101.02	105.00	9.74	3.93
2014	100.00	82.63	105.06	4.59	101.02	102.00	9.91	4.39
2015	100.00	82.63	105.06	5.05	101.02	100.00	10.20	4.85
2016	100.00	82.63	105.06	5.51	101.02	100.00	10.20	5.31
2017	100.00	82.63	105.06	5.97	101.02	100.00	10.20	5.77
2018	101.35	83.75	106.49	6.21	102.40	101.35	10.34	6.01
2019	103.38	85.44	108.65	6.33	104.47	103.38	10.55	6.13
2020	105.45	87.16	110.84	6.46	106.58	105.45	10.76	6.26
2021	107.56	88.92	113.08	6.58	108.73	107.56	10.98	6.38
2022+	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year
Constant	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/bbl	US$/bbl	Cdn$/mmbtu	Cdn$/mmbtu
All years	96.19	78.81	105.28	3.71	96.04	111.85	9.43	3.32

(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) NYMEX WTI crude oil at Cushing, Oklahoma. Price used when determining SCO reserves presented as In Situ and Mining reserves.

(3) WCS stream at Hardisty, Alberta. Price used when determining bitumen reserves presented as In Situ reserves.

(4) Edmonton pentanes plus. Price used when determining the cost of diluent associated with bitumen reserves presented as In Situ reserves. A bitumen/diluent ratio of approximately 2:1 was used. Price also used when determining certain NGL reserves.

(5) Natural gas price at AECO. Price used when determining natural gas reserves (primarily in Alberta) presented as North America Onshore reserves. Price also used when determining natural gas input costs for the production of SCO and bitumen reserves.

(6) Light sweet crude oil (40 API, 0.3% sulphur) at Edmonton, Alberta. Price used when determining light and medium oil reserves presented as North America Onshore reserves.

(7) Brent blend crude oil FOB North Sea. Price used when determining light and medium oil reserves presented as East Coast Canada reserves, North Sea reserves and Other International reserves.

(8) National Balancing Point (U.K.). Price used when determining natural gas reserves presented as North Sea reserves and Other International reserves.

(9) Natural gas prices at B.C. Westcoast Station 2. Price used when determining natural gas reserves (primarily in B.C.) presented as North America Onshore reserves.

Disclosure of After-Tax Net Present Values of Future Net Revenue

Values presented in the table for Net Present Value of Future Net Revenues After Income Taxes reflect income tax burdens of assets at an individual asset level (for Mining, In Situ and East Coast Canada) or at a business area or legal entity level (for North Sea and North America Onshore) based on tax pools associated with that business area or legal entity. Income taxes for Other International assets are determined by their respective PSCs. Suncor's actual corporate legal entity structure for income taxes and income tax planning have not been considered, and, therefore, the total value for income taxes presented in the table may not provide an estimate of the value at the corporate entity level, which may be significantly different. The 2011 audited Consolidated Financial Statements and the MD&A should be consulted for information on income taxes at the corporate entity level.

Future Development Costs
as at December 31, 2011
(forecast prices and costs)

($ millions)	2012	2013	2014	2015	2016	Remainder	Total	Discounted At 10%
Proved								
Mining	2 173	2 231	1 634	1 332	1 345	27 867	36 582	16 661
In Situ	1 643	1 337	1 048	1 130	1 521	23 761	30 440	13 426
East Coast Canada	515	129	111	17	47	135	954	794
North America Onshore	15	73	39	24	23	29	203	157
Total Canada	4 346	3 770	2 832	2 503	2 936	51 792	68 179	31 038
North Sea	406	318	183	77	41	—	1 025	899
Other International	118	132	47	11	10	5	323	282
Total Proved	4 870	4 220	3 062	2 591	2 987	51 797	69 527	32 219
Proved Plus Probable								
Mining	2 254	2 321	1 697	1 389	1 411	38 466	47 538	18 779
In Situ	1 600	1 681	1 974	3 099	2 873	70 750	81 977	21 419
East Coast Canada	741	661	648	441	352	743	3 586	2 656
North America Onshore	62	156	87	24	23	28	380	310
Total Canada	4 657	4 819	4 406	4 953	4 659	109 987	133 481	43 164
North Sea	406	318	213	102	72	—	1 111	963
Other International	118	283	111	106	106	80	804	632
Total Proved Plus Probable	5 181	5 420	4 730	5 161	4 837	110 067	135 396	44 759

Development costs include costs associated with both developed and undeveloped reserves. Significant development activities for 2012 are expected to include:

- For Mining, costs for mine train relocations and mine train replacements at Syncrude and new tailings management facilities for Oil Sands Base. Remaining development costs are sustaining capital investments, which maintain production capacities at existing facilities, and include costs for major maintenance, catalyst, truck and shovel replacement, and the replacements for utilities, roads and other facilities.
- For In Situ, facility and new well costs for the Firebag Stage 4 expansion and new wells at MacKay River and Firebag to sustain bitumen supply for existing central processing facilities.
- For East Coast Canada, costs for development drilling at Terra Nova, White Rose and Hibernia, procurement of subsea infrastructure for the HSEU, H_2S remediation activities, the FPSO swivel replacement and other dockside maintenance activities at Terra Nova, and early development activities for Hebron.
- For North Sea, costs for development drilling and facility upgrades at Buzzard, including accommodations, sand management, and produced water reinjection, and early development activities for Golden Eagle.
- For North America Onshore, costs for the development of the Wilson Creek and Ferrier fields in the Cardium oil formation.
- For Other International, costs for upgrades and maintenance to facilities in Libya. Due to the sanctions and suspension of operations in Syria, no development costs were included for 2012.

Management currently believes existing cash balances, internally generated cash flows 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.

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 no legal liability or constructive obligation for reclamation exists, potential costs have been excluded from the company's abandonment and reclamation cost estimates.

At December 31, 2011, Suncor estimated its undiscounted, uninflated abandonment and reclamation costs, net of estimated salvage value, for surface leases, wells, facilities and pipelines pertaining to its upstream assets to be approximately $7.2 billion (discounted at 10%, approximately $2.1 billion). Suncor estimates that it will incur $1.284 billion (undiscounted: 2012 – $408 million, 2013 – $463 million, 2014 – $413 million) of its identified abandonment and reclamation costs during the next three years, over 85% of which is associated with mining operations. This cost estimate does not include the company's estimated abandonment and reclamation costs for its Refining and Marketing assets ($71 million, undiscounted and uninflated).

Approximately $2.2 billion (undiscounted) 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 6,300 net reserves wells, including a forecasted number of future wells for undeveloped reserves, for our in situ and conventional activities. This figure counts in situ well pairs as one abandonment, whereas previous figures reported by Suncor counted in situ well pairs as two separate abandonments.

Abandonment and reclamation costs included in Suncor's $7.2 billion total that are excluded from the determination of future net revenues from reserves include, but are not limited to, costs related to the reclamation of disturbed land from oil sands mining activities, the treatment of oil sands tailings, the decommissioning of oil sands and natural gas processing facilities and well pads, lease sites, and the abandonment of wells to which no reserves have been assigned.

Additional Information Relating to Reserves Data

Gross Proved and Probable Undeveloped Reserves [(1)(2)]

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

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.

Gross Proved Undeveloped Reserves
(forecast prices and costs)

	Prior		2009		2010		2011	
	First Attributed	Total at December 31 2008	First Attributed	Total at December 31 2009	First Attributed	Total at December 31 2010	First Attributed	Total at December 31 2011
SCO (mmbbls)								
Mining	—	—	—	—	—	—	—	—
In Situ	766.0	766.0	121.0	564.0	14.0	651.0	—	502.0
Total SCO	766.0	766.0	121.0	564.0	14.0	651.0	—	502.0
Bitumen (mmbbls)								
Mining	—	—	—	—	—	—	—	—
In Situ	—	—	—	427.0	2.0	360.0	315.0	661.1
Total Bitumen	—	—	—	427.0	2.0	360.0	315.0	661.1
Light & Medium Oil (mmbbls)								
East Coast Canada	—	—	35.0	35.0	3.0	28.0	1.4	26.6
North America Onshore	0.1	0.1	0.2	0.3	—	0.2	0.1	0.3
Total Canada	0.1	0.1	35.2	35.3	3.0	28.2	1.5	26.9
North Sea [(3)]	—	—	68.0	68.0	—	19.0	24.6	43.3
United States [(4)]	—	—	8.3	8.3	—	—	—	—
Other International [(5)]	—	—	—	—	6.0	6.0	1.8	5.8
Total Light & Medium Oil	0.1	0.1	111.5	111.6	9.0	53.2	27.9	76.0
Natural Gas (bcf)								
North America Onshore – Canada	31.2	31.2	29.1	15.6	32.0	118.4	2.1	78.7
North Sea [(3)]	—	—	—	—	—	1.0	1.5	2.7
United States [(4)]	—	—	23.9	23.9	—	—	—	—
Other International [(5)]	—	—	413.0	413.0	—	—	—	—
Total Natural Gas	31.2	31.2	466.0	452.5	32.0	119.4	3.6	81.4
NGLs (mmbbls)								
North America Onshore – Canada	0.1	0.1	0.3	0.4	—	0.1	—	0.1
North Sea [(3)]	—	—	1.0	1.0	—	—	—	0.1
Other International [(5)]	—	—	9.0	9.0	—	—	—	—
Total NGLs	0.1	0.1	10.3	10.4	—	0.1	—	0.2
Total (mmboe)	771.4	771.4	320.5	1 188.4	30.4	1 084.2	343.5	1 252.8

Gross Probable Undeveloped Reserves
(forecast prices and costs)

	Prior		2009		2010		2011	
	First Attributed	Total at December 31 2008	First Attributed	Total at December 31 2009	First Attributed	Total at December 31 2010	First Attributed	Total at December 31 2011
SCO (mmbbls)								
Mining	617.0	617.0	264.0	264.0	—	215.0	—	263.0
In Situ	1 746.0	1 746.0	174.0	595.0	6.0	400.0	916.0	1 212.0
Total SCO	2 363.0	2 363.0	438.0	859.0	6.0	615.0	916.0	1 475.0
Bitumen (mmbbls)								
Mining	—	—	—	—	—	37.0	—	—
In Situ	—	—	—	1 550.0	8.0	1 835.0	38.0	669.0
Total Bitumen	—	—	—	1 550.0	8.0	1 872.0	38.0	669.0
Light & Medium Oil (mmbbls)								
East Coast Canada	—	—	80.0	80.0	7.0	85.0	143.2	217.4
North America Onshore	—	—	5.1	5.1	0.3	3.5	0.7	2.0
Total Canada	—	—	85.1	85.1	7.3	88.5	143.9	219.4
North Sea [3]	—	—	35.0	35.0	—	15.0	13.8	17.1
United States [4]	—	—	3.8	3.8	—	—	—	—
Other International [5]	—	—	62.0	62.0	8.0	11.0	3.8	14.5
Total Light & Medium Oil	—	—	185.9	185.9	15.3	114.5	161.5	251.0
Natural Gas (bcf)								
North America Onshore – Canada	76.3	76.3	235.2	233.2	75.2	136.2	3.2	86.9
North Sea [3]	—	—	50.0	50.0	—	1.0	1.2	1.5
United States [4]	—	—	12.0	12.0	—	—	—	—
Other International [5]	—	—	651.0	651.0	—	240.0	221.4	347.4
Total Natural Gas	76.3	76.3	948.2	946.2	75.2	377.2	225.8	435.8
NGLs (mmbbls)								
North America Onshore – Canada	0.2	0.2	0.9	1.0	0.1	1.0	—	0.8
North Sea [3]	—	—	1.0	1.0	—	—	—	—
Other International [5]	—	—	18.0	18.0	—	8.0	6.0	11.5
Total NGLs	0.2	0.2	19.9	20.0	0.1	9.0	6.0	12.3
Total (mmboe)	2 375.9	2 375.9	801.8	2 772.6	41.9	2 673.4	1 159.1	2 479.9

(1) The term First Attributed represents undeveloped reserves additions including acquisitions, discoveries and extensions pertaining to the year in which the events first occurred. Undeveloped reserves first attributed in 2009 primarily include those acquired as a result of the merger with Petro-Canada.

(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) In these tables, "North Sea" includes additional properties previously held by Suncor in the Netherlands portion of the North Sea.

(4) Undeveloped U.S. reserves were acquired in the merger with Petro-Canada in 2009 and subsequently disposed in 2010.

(5) In these tables "Other International" includes additional properties previously held by Suncor in Trinidad and Tobago.

Undeveloped In Situ reserves, which constitute approximately 93% of Suncor's gross proved undeveloped reserves and 76% of Suncor's gross probable undeveloped reserves, will take more than two years to develop. Management uses integrated plans to forecast future development. These detailed plans align current production, processing and pipeline capacities, capital spending commitments and future development for the next ten years, and are reviewed and updated annually for internal and external factors affecting planned activity. Reserves are developed as required to keep processing capacity full. The timing associated with developing undeveloped reserves is a function of the forecasts of the declining production from existing well pairs. Suncor has delineated In Situ reserves to a high degree of certainty through seismic data and core hole drilling, consistent with COGE guidelines. In most cases, proved reserves have been drilled to a density of 16 wells per section, well in excess of the eight wells per section required for regulatory approval. In order to determine the economic cutoffs of undeveloped reserves, geological information is tested against existing production analogues that use established technology.

Undeveloped Mining reserves, which constitute approximately 11% of Suncor's gross probable undeveloped reserves, relate solely to the Syncrude Aurora South mine, which has regulatory approvals substantially in place and is well-delineated by core hole drilling. The owners of the Syncrude joint venture do not expect that the Aurora South mine will come on-stream in this decade.

Undeveloped conventional (light and medium oil, natural gas and NGLs) reserves constitute approximately 7% of Suncor's gross proved undeveloped reserves and approximately 13% of Suncor's gross probable undeveloped reserves. As part of its active portfolio management process, Suncor reviews the economic viability of its conventional properties containing

undeveloped reserves using industry standard economic evaluation techniques and its 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 undeveloped 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.

Properties with no Attributed Reserves

The following table is a summary of properties to which no reserves are attributed as at December 31, 2011. 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.

Country	Gross Hectares	Net Hectares
Canada	5 093 830	3 740 853
Libya	2 950 978	1 339 489
U.S. – Alaska	1 161 123	387 002
Norway	501 791	209 691
Syria	345 194	345 194
U.K.	138 437	44 574
Australia (overriding royalty interest only)	113 027	—
Total	10 304 380	6 066 803

Suncor holds interests in a diverse portfolio of undeveloped petroleum assets in Canada and in several international areas. 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. Each year, as part of the company's active management process to review the economic viability of its conventional properties, 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 2012, Suncor's rights to explore, develop and exploit will expire for 189,374 net hectares in Canada, 131,308 net hectares in Alaska and 39,840 net hectares in the U.K. portion of the North Sea. No land tenure expiries are scheduled to occur for either Mining or In Situ properties for 2012. Substantial portions of expiring lands may have their tenure continued beyond 2012 through the conduct of work programs and/or the payment of prescribed fees to the rights owner.

Oil and Gas Properties and Wells

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

Suncor's Oil Sands operations recover 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 NGLs 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 operated and non-operated oil and gas wells associated with the company's reserves as at December 31, 2011:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	253.0	236.9	134.0	130.7	4 268.0	2 916.4	206.0	168.6
British Columbia	15.0	9.6	6.0	5.8	235.0	200.5	87.0	70.2
Saskatchewan	–	–	–	–	738.0	268.1	91.0	43.5
Newfoundland	61.0	15.6	2.0	0.8	–	–	–	–
North Sea	26.0	7.8	4.0	1.2	–	–	–	–
Other International	213.0	106.5	77.0	40.0	–	–	6.0	6.0
Total	568.0	376.4	223.0	178.5	5 241.0	3 385.0	390.0	288.3

There are no production wells associated with Mining properties. Suncor has no proved developed non-producing reserves or probable developed 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, which require further capital for completion and tie in to facilities to bring the wells on-stream. This capital requirement is significant enough that the reserves are not classified as developed. SAGD well pairs are counted as one well.

In Syria, wells previously reported as producing have been reclassified to non-producing, consistent with the reclassification of proved developed producing reserves and probable developed producing reserves to their respective non-producing categories.

The majority of remaining conventional non-producing reserves have been in their current non-producing state for less than four years and are forecast to be brought on-stream within the next two years. These remaining non-producing reserves are primarily associated with:

- Recently drilled wells to be brought on production in 2012;
- Secondary zones forecast to be brought on-stream over the next two years;
- Wells requiring workovers;
- Wells temporarily shut in due to operational issues at facilities; and
- Gas production being re-injected to maintain gas cap pressure on oil producing zones until depletion of the oil zones.

Costs Incurred

The table below summarizes the company's capital expenditures related to its reserves activities for the year ended December 31, 2011.

($ millions)	Exploration Costs	Proved Property Acquisition Costs	Unproved Property Acquisition Costs	Development Costs	Total
Canada – Mining and In Situ	57	—	200	4 362	4 619
Canada – East Coast Canada and North America Onshore	77	—	1	476	554
North Sea	97	—	29	74	200
Other International	36	—	—	37	73
Total	267	—	230	4 949	5 446

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, 2011.

Total number of wells completed	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Canada				
Oil	—	—	73.0	64.6
Natural Gas	1.0	0.5	105.0	52.3
Dry Hole	2.0	2.0	2.0	1.2
Service	—	—	8.0	5.0
Stratigraphic Test	22.0	13.8	617.0	311.6
Total	25.0	16.3	805.0	434.7
North Sea				
Oil	—	—	4.0	1.2
Natural Gas	—	—	—	—
Dry Hole	1.0	0.3	—	—
Service	—	—	1.0	0.3
Stratigraphic Test	—	—	—	—
Total	1.0	0.3	5.0	1.5
Other International				
Oil	—	—	4.0	2.5
Natural Gas	—	—	—	—
Dry Hole	1.0	0.5	1.0	1.0
Service	—	—	—	—
Stratigraphic Test	—	—	—	—
Total	1.0	0.5	5.0	3.5

Significant exploration and development wells completed in 2011 included:

- For Mining, core hole drilling programs and other survey work at Oil Sands Base and Syncrude to provide additional information on areas the company expects to mine in the near term.
- For In Situ, infill wells at Firebag Stage 1 and Stage 2 well pads, new wells at MacKay River and Firebag to help sustain bitumen supply for existing central processing facilities, and core hole drilling at Firebag, MacKay River and Meadow Creek to further delineate reserves and resources.
- For East Coast Canada, the Ballicatters exploration well, a production well at Terra Nova, and development drilling for Hibernia, the HSEU and the White Rose Extensions.
- For International, exploration drilling on the Butch prospect in the Norway portion of the North Sea, development drilling at Buzzard, oil development wells in Libya, and one oil development well in Syria (prior to sanctions related to oil investment and, later, the suspension of operations).
- For North America Onshore, development drilling of the Wilson Creek and Ferrier fields in the Cardium oil formation, the Medicine Hat shallow gas region, and the Kobes area of the Montney shale gas formation.

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 and Other International. Average price realized is net of transportation costs, but before royalties.

	2011			
	Three months ended			
	Mar 31	Jun 30	Sept 30	Dec 31
Canada				
Oil Sands [1]				
Average total production (mbbls/d)	360.6	277.2	362.5	356.8
Average In Situ bitumen production (mbbls/d)	87.3	85.8	83.8	101.4
Average price realized ($/bbl)	83.74	93.16	86.40	98.01
Royalties ($/bbl)	(3.33)	(5.49)	(6.28)	(8.17)
Total cash operating costs ($/bbl)	(36.42)	(49.73)	(37.06)	(40.42)
In Situ cash operating costs ($/bbl)	(22.00)	(24.15)	(27.05)	(29.15)
Light & Medium Oil				
Average total production (mbbls/d)	65.0	65.0	69.1	63.4
Average price realized ($/bbl)	104.01	112.19	111.30	111.77
Royalties ($/bbl)	(32.04)	(34.99)	(33.56)	(36.95)
Production costs ($/bbl)	(8.14)	(7.26)	(6.69)	(9.36)
Netback ($/bbl)	63.83	69.94	71.05	65.46
Natural Gas [2]				
Average total production (mmcfe/d)	411	402	375	365
Average price realized ($/mcfe)	4.52	4.90	4.56	4.31
Royalties ($/mcfe)	(0.44)	(0.54)	(0.48)	(0.48)
Production costs ($/mcfe)	(1.49)	(1.35)	(1.71)	(1.66)
Netback ($/mcfe)	2.59	3.01	2.37	2.17
North Sea				
Light & Medium Oil [3]				
Average total production (mboe/d)	65.7	32.7	33.1	55.0
Average price realized ($/boe)	93.74	113.24	111.60	106.41
Royalties ($/boe)	(0.00)	(0.00)	(0.00)	(0.00)
Production costs ($/boe)	(6.86)	(6.66)	(6.34)	(3.64)
Netback ($/boe)	86.88	106.58	105.26	102.77
Other International				
Light & Medium Oil				
Average total production (mboe/d)	24.2	—	—	24.8
Average price realized ($/boe)	99.07	—	—	109.58
Royalties ($/boe)	(80.75)	—	—	(61.85)
Production costs ($/boe)	(2.85)	—	—	(8.12)
Netback ($/boe)	15.47	—	—	39.61
Natural Gas [4]				
Average total production (mboe/d)	17.1	16.9	18.9	16.0
Average price realized ($/boe)	84.58	95.28	95.49	91.69
Royalties ($/boe)	(32.04)	(38.54)	(43.28)	(35.11)
Production costs ($/boe)	(6.19)	(7.66)	(6.06)	(8.20)
Netback ($/boe)	46.35	49.08	46.15	48.38

(1) Suncor tracks cash operating cost for its Oil Sands operations, which includes more expenses than strictly 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. Amounts presented include results from the company's share in the Syncrude joint venture.

(2) Volumes include NGLs and crude oil from natural gas wells.

(3) Volumes include field production for natural gas and NGLs.

(4) Volumes include approximate annual oil production of 1.5 mboe/d from Syria.

The following table provides the production volumes for each of Suncor's important fields for the year ended December 31, 2011.

	SCO and Bitumen	Light & Medium Oil	Natural Gas	NGLs	Total
	mbbls/d	mbbls/d	mmcfe/d	mbbls/d	mboe/d
Mining – Suncor [1]	228.6	—	—	—	228.6
Mining – Syncrude [1]	34.6	—	—	—	34.6
Firebag [2]	48.1	—	—	—	48.1
MacKay River [2]	27.9	—	—	—	27.9
Buzzard	—	41.9	4.3	0.3	42.9
Hibernia	—	30.9	—	—	30.9
White Rose	—	18.5	—	—	18.5
Terra Nova	—	16.2	—	—	16.2

(1) All production attributed to Mining represents SCO.

(2) Estimates of production representing a mixture of upgraded SCO and non-upgraded bitumen.

Production Estimates

The table below outlines the volume of the company's production of gross proved and gross proved plus probable reserves estimated for the year ending December 31, 2012, 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. Production estimates for 2012 for proved plus probable reserves from: Suncor's mining operations (excluding Syncrude) are 232 mbbls/d of SCO, approximately 47% of total estimated production for 2012; and from Firebag are 72 mbbls/d of SCO and bitumen, approximately 15% of total estimated production for 2012.

	SCO		Bitumen		Light & Medium Oil		Natural Gas		NGLs	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	mbbls/d	mbbls/d	mbbls/d	mbbls/d	mboe/d	mboe/d	mmcfe/d	mmcfe/d	mboe/d	mboe/d
Canada										
Proved	325.3	296.9	21.2	19.4	40.9	32.9	287.1	243.9	2.3	1.7
Probable	24.2	21.7	0.4	(0.7)	14.3	10.3	8.7	7.1	0.2	0.1
Proved Plus Probable	349.5	318.6	21.6	18.7	55.2	43.2	295.8	251.0	2.5	1.8
North Sea										
Proved	—	—	—	—	54.0	54.0	5.8	5.8	0.5	0.5
Probable	—	—	—	—	—	—	—	—	—	—
Proved Plus Probable	—	—	—	—	54.0	54.0	5.8	5.8	0.5	0.5
Other International										
Proved	—	—	—	—	37.0	13.8	—	—	—	—
Probable	—	—	—	—	—	—	—	—	—	—
Proved Plus Probable	—	—	—	—	37.0	13.8	—	—	—	—

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, 2011. These commitments run through 2013 and are primarily for conducting seismic programs and drilling exploration wells.

Country/Area ($ millions)	2012	Total
Canada	1	24
North Sea	158	216
Other International	128	369

Forward Contracts and Transportation Obligations

Suncor may use financial derivatives to manage its exposure to fluctuations in commodity prices; however, Suncor did not have any such material financial derivative transactions in 2011. A description of Suncor's use of such instruments is provided in the 2011 audited Consolidated Financial Statements and related MD&A for the year ended December 31, 2011.

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.

Tax Horizon

In 2011, 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 the majority of its Canadian earnings. Suncor's 2011 audited Consolidated Financial Statements were prepared using the 2014 effective Canadian tax rate to record income taxes, as this rate would apply to the reversal of long-term temporary differences. Based on projected future net earnings, Suncor may be cash taxable in Canada by 2013.

Contingent Resources

GLJ conducted an independent assessment of Best Estimate contingent resources volumes for all of Suncor's Mining properties and for Suncor's In Situ properties to which reserves are attributed (Firebag and MacKay River). For In Situ properties without attributed reserves, GLJ audited assessments of Best Estimate contingent resources volumes (approximately 41% of In Situ contingent resources) prepared by Suncor's internal qualified reserves evaluators. Best Estimate contingent resources for other properties were prepared by Suncor's internal qualified reserves evaluators. All contingent resources estimates were conducted in accordance with the COGE Handbook.

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 recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or lack of infrastructure or markets. 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.

There is no certainty that all or any portion of the contingent resources will be commercially viable to produce. 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. For movement of contingent resources to reserves categories, all projects must have an economic depletion plan and may require, among other things, additional delineation drilling, regulatory applications, or sanction from the company's Board and any joint venture owners to proceed with development.

In general, significant factors that may change contingent resources estimates include further delineation drilling, which could change the estimates either positively or negatively, future technology improvements, which would positively affect the estimates, and additional processing capacity that could affect the volumes recoverable or type of production. 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 there is a high level of certainty of receiving all regulatory and corporate approvals, and all other contingencies are removed, the resources may then be reclassified as reserves.

Effective December 31, 2011, Suncor's Best Estimate of gross contingent resources is set out in the table below. Volumes represent Suncor's working interest in properties with contingent resources.

Best Estimate Gross Contingent Resources	SCO	Bitumen	Light & Medium Oil	Natural Gas	NGLs	Total
	mmbbls	mmbbls	mmbbls	bcf	mmbbls	mmboe
Mining	4 582	2 156	—	—	—	6 738
In Situ	6 432	6 020	—	—	—	12 452
East Coast Canada	—	—	247	2 203	—	614
North America Onshore [1]	—	—	116	8 017	13	1 465
Total Canada	11 014	8 176	363	10 220	13	21 269
North America Onshore – U.S.	—	—	—	133	—	22
North Sea [2]	—	—	45	36	—	52
Other International	—	—	481	245	1	522
As at December 31, 2011	11 014	8 176	889	10 634	14	21 865
As at December 31, 2010	12 462	5 291	956	10 370	17	20 454

(1) Contingent resources include offshore fields in the Arctic Islands.

(2) Contingent resources are offshore Norway.

Contingent resources increased to 21,865 mmboe at December 31, 2011 from 20,454 mmboe at December 31, 2010. Increases to contingent resources included extensions of the MacKay River and Meadow Creek leases, acquisition of additional leases in the Audet area, technical revisions for In Situ assets, recognition of potential Hibernia secondary zones, and volumes attributed to discoveries in the Ballicatters, Butch and Wilson Creek areas. The net effects of Suncor's transactions with Total E&P, which included the acquisition of an interest in Joslyn, the partial disposition of our interest in Fort Hills and a change in assumption that reclassified remaining Fort Hills reserves from SCO to bitumen, also increased total contingent resources. These increases were partially offset by the transfer of resources to proved plus probable reserves for Golden Eagle and Hebron, and asset dispositions.

Suncor has assumed that some 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 resources volumes would be higher because of the yield factor applied to bitumen volumes when upgraded into SCO. Conversely, to the extent that more volumes are upgraded, total contingent resources volumes would be lower.

Generally, the timing for the economic assessments of contingent resources will be determined by Suncor's long-term resource development plan and its forecast for economic conditions. Management uses integrated plans to forecast future development of resources. These plans align current and planned production, current and forecasted market conditions, processing and pipeline capacities, capital spending commitments and related future development plans. These plans are reviewed and updated annually for internal and external factors affecting these planned activities. In particular, as Suncor's Oil Sands reserves base depletes, the company anticipates that it will look to develop its other Mining and In Situ properties, at which time the assessment of the economic viability of specific properties with contingent resources will be made.

Details of Suncor's contingent resources and a categorization of the contingencies ascribed to these resources are provided below.

Mining Contingent Resources

Mining contingent resources comprise approximately 31% of Suncor's total contingent resources, with 59% of these contingent resources on properties in which Suncor has a 100% working interest and the remainder forming part of joint arrangements where Suncor has working interests varying from 12% to 40.8%.

Economic Contingencies

GLJ has tested the economic viability of the Fort Hills and Joslyn North projects, which constitute approximately 25% of total Mining contingent resources, and determined them to be economic. The economic status of remaining Mining contingent resources is currently undetermined; however, the company anticipates that the contingent resources will be economic to develop under current market conditions, as the potential development of these contingent resources would reflect the application of established technology and reasonable assumptions for mine pit design.

Non-Technical Contingencies

Given the concern within the industry with respect to the potential cost escalation of large mining projects, the reclassification of Mining contingent resources to reserves is largely contingent upon an assessment that development will be sanctioned and

commence within a reasonable time frame. The Fort Hills and Joslyn North mining projects have substantially all regulatory approvals in place, but final investment decisions based on development plans currently being finalized await decision by the joint venture owners, and, as a result, it is Suncor's view that the development of these contingent resources in the near term is not sufficiently assured to support reclassification to reserves. For Suncor's remaining Mining contingent resources, regulatory permits must be obtained before a project sanction decision by Suncor's Board and joint venture owners, as applicable, is considered.

In Situ Contingent Resources

In Situ contingent resources comprise approximately 57% of Suncor's total contingent resources, with 59% of these contingent resources on properties in which Suncor has a 100% working interest and the remainder forming part of joint arrangements where Suncor has working interests varying from 10% to 75%. These contingent resources are all in the Athabasca oil sands area and over 80% of the contingent resources are in, or immediately adjacent to, existing MacKay River or Firebag operations.

The primary risk associated with developing In Situ contingent resources relates to actual production performance versus performance estimated based on the geological data used in the production forecast. The geological data varies substantially as a result of the density of core holes used in the analysis. The density can be as low as one well per section, and as high as 16 wells per section.

Economic Contingencies

The economic status of In Situ contingent resources is currently undetermined; however, the company anticipates that the contingent resources will be economic to develop under current market conditions. Technical net pay cutoffs are consistent with, and based upon, the same fiscal conditions as those used in the determination of proved plus probable reserves for Firebag and MacKay River, or are analogous to existing in situ operations successfully developed by other entities in the oil sands industry. Suncor anticipates that its In Situ contingent resources will be recoverable using established SAGD processes.

Contingent resources have been assigned to certain sections associated with Firebag and MacKay River development areas. These volumes have not been classified as proved plus probable reserves in part because drilling density is inadequate for reliable mapping of effective pay intervals. However, the company has two-dimensional seismic control, minimum mapped effective pay thicknesses of 15 metres for Firebag and 14 metres for MacKay River, and drilling density greater than or equal to one vertical well per section (except when that section is bound by sections with greater than or equal to one well per section). The company expects that an assessment of the economic viability of these resources will be undertaken when drilling density has increased such that it is adequate for reliable mapping of effective pay intervals and as the company's long-term plans require additional bitumen to keep existing processing capacities associated with these assets full.

Contingent resources for other In Situ properties (Chard, Kirby, Lewis, Meadow Creek and MacKay River outside of the development areas noted above) were assigned to sections with core holes, or lands within two legal subdivisions of a delineation well and having net continuous bitumen pay greater than 15 metres. These contingent resources require the completion of further reservoir studies and delineation drilling, as well as the preparation of development plans and facility designs prior to reserves being assigned. The company expects that an assessment of the economic viability of these contingent resources will be undertaken as the company's long-term plans require additional bitumen.

Non-Technical Contingencies

The reclassification of In Situ contingent resources to reserves is also largely contingent upon an assessment that development will be sanctioned and commence within a reasonable time frame. The contingent resources associated with development areas for Firebag and MacKay River have regulatory approvals in place, but a final investment decision is subject to an assessment of economic viability and approval by Suncor's Board. For remaining In Situ contingent resources, the company must still obtain regulatory approvals and project sanction by Suncor's Board and joint venture owners, as applicable.

Other Contingent Resources

Other contingent resources are mainly conventional sources of oil and gas associated with Suncor's Exploration and Production segment. These other contingent resources comprise approximately 12% of Suncor's total contingent resources and are anticipated to be recoverable using established technologies. These other contingent resources primarily include:

- For North America Onshore, discovered resources in the Arctic Islands, Mackenzie Delta, Mackenzie Corridor, Beaufort Sea, and in the Alaska Foothills, and a tight oil play in the Gilby/Wilson area of Alberta.
- For East Coast Canada, extensions of existing producing oilfields and Hebron, natural gas resources associated with existing producing oilfields, and other hydrocarbon accumulations that are not currently producing, including those offshore Newfoundland and Labrador.
- For North Sea, discoveries offshore Norway.
- For Other International, in both Libya and Syria, undeveloped portions within existing producing fields and other discovered hydrocarbon accumulations that are not currently producing, and, for Syria, 2012 production estimates.

Economic Contingencies

Except as noted below, the economic status of other contingent resources is undetermined. In general, further reservoir studies and delineation drilling, and preparation of development plans and facility designs are required to make a determination as to whether these contingent resources would be economic or not under current conditions.

For North America Onshore, contingent resources associated with the Gilby/Wilson tight oil play have been determined to be economic. The economic status of contingent resources associated with certain fields in the Arctic Islands is undetermined, but anticipated to be economic provided the natural gas resources are able to be delivered to markets outside of North America. Remaining North America Onshore contingent resources are primarily in geographically remote areas and are sub-economic due to lack of processing and transportation infrastructure in these areas. These areas require commitments to identify the existence of sufficient resources for economic development, following which construction of processing facilities and/or transportation infrastructure would be required, which is not anticipated to occur within the next five years.

For East Coast Canada, contingent resources for Hebron and some for Terra Nova have been determined to be economic. The company anticipates that it will assess the economic viability of contingent resources for Hibernia and White Rose within the next five years and that these contingent resources will be economic to develop under current market conditions. Timing for completion of economic evaluation of remaining contingent resources is not anticipated to occur within the next five years.

For the North Sea, contingent resources are in the appraisal stage. The economic status of these contingent resources is undetermined, but the company anticipates that it will assess their economic viability within the next five years and that these contingent resources will be economic to develop under current market conditions.

For Other International, contingent resources in Syria are currently sub-economic, but would be economic in the absence of force majeure under the company's contractual obligations. In Libya, contingent resources associated with producing fields are economic, while the economic viability of resources associated with non-producing fields is undetermined, but the company anticipates that it will complete economic assessments for these fields in the next five years.

Non-Technical Contingencies

The reclassification of contingent resources associated with the Exploration and Production segment to proved plus probable reserves is primarily contingent upon the receipt of appropriate regulatory approvals, and an assessment that development will be sanctioned by Suncor's Board and joint venture partners, as applicable, and commence within a reasonable time frame. Contingent resources for some North America Onshore properties in geographically remote areas are also contingent upon the development of a suitable regulatory framework.

The estimated production for Syria for 2012 has been classified as contingent resources, contingent upon Suncor being able to record production and receive payment. In order for this to occur, sanctions that are applicable to Suncor and that were initiated as a result of political unrest in Syria must be lifted so that the company can conduct business with its joint venture partner in Syria. For remaining contingent resources associated with Suncor's Syrian assets, a daily contract quantity for production, which limits the rate at which gas can be produced, is the primary contingency. This production constraint prevents a portion of the resources from being produced within the contract period. This contingency could be removed through contract extension or a higher daily contract quantity at a sufficient sales price.

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, as well as 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 unable to predict what additional legislation or amendments may be enacted. The following discussion outlines some of the principal aspects of legislation, regulations and agreements governing Suncor's operations.

Pricing, Marketing and Exporting Crude 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 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 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 apportionment of capacity on 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.

Recently, pipeline capacity to support the growth of the oil sands industry in Canada has been the subject of political and environmental debate. Suncor supports the responsible development of pipeline infrastructure that would open access to other markets.

Royalties, Incentives and Income Taxes

Canada

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 SCO, bitumen, crude oil, NGL 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 revenues received from 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 was 16.5% effective January 1, 2011 for active business income, including resource income, and decreased to 15% on January 1, 2012. The average provincial income tax rate for Suncor in 2011 was 10.69%, which is expected to decrease to 10.39% in 2014 when enacted provincial income tax rate reductions become effective.

Other Jurisdictions

Operations in the U.S are subject to the U.S. federal tax rate of 35% and various state-level taxes, primarily 4.63% in Colorado.

There are no royalties on production from the U.K. portion of the North Sea; however, the income tax rate on oil and gas profits is 62%. This rate increased from 50% effective March 23, 2011 after the U.K. government announced an increase in its supplementary charge from 20% to 32%.

Suncor earns refundable tax credits related to eligible exploration spending in Norway at a rate of 78%.

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.

Under our EPSAs in Libya, income taxes are payable. Suncor prepares corporate income tax declarations that are processed by the NOC who, in turn, obtains a tax clearance certificate from tax authorities that is forwarded to Suncor. The NOC remits taxes on Suncor's behalf. Until tax certificates are received, Suncor records both an income tax payable to the taxation authority and an offsetting income tax receivable from the NOC.

For our PSCs in Syria, Suncor has been advised that income taxes are not payable until the Ebla project reaches payout. When payable, income taxes shall be assumed, paid and discharged on behalf of Suncor by the GPC.

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, grant tenure in the form of exploration, significant discovery and production licences.

In many other international jurisdictions, 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, this legislation requires that the company abandon and reclaim well and facility sites to the satisfaction of provincial authorities and, in some cases, this burden may remain with the company even after disposition of an asset to a third party. Compliance with such legislation can require significant expenditures, and a breach of these 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 greenhouse gas (GHG) emissions 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, including the recently announced Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring. These statutes, regulations and frameworks relate to such issues as tailings management, water use and land use. While the financial implications of statutes, regulations and frameworks under development 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 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 the nature of any future 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, persisting with land reclamation activities, installing new emissions abatement equipment and working to advance other environmental technologies such as carbon capture and sequestration.

The scope of recent environmental regulation and initiatives has had an impact on many areas important to Suncor's operations, some of which are summarized in the following subsections:

Climate Change

Suncor operates in many jurisdictions that have regulated, or have proposed to regulate, industrial GHG emissions. Those jurisdictions that have regulated GHG emissions generally support policies based on (i) caps on the intensity of GHG emissions, (ii) a carbon price, possibly through a cap-and-trade system, (iii) a tax, (iv) a hybrid of a tax and a cap-and-trade system, and (v) policies including other measures such as low carbon fuel and renewable fuel standards. Suncor participates in the consultation process for the design of proposed regulations and other efforts to harmonize regulations across jurisdictions within North America, both directly and indirectly through industry associations.

Suncor believes that the responsibility for managing environmental and 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. Suncor's CEO and COO hold top executive responsibility for sustainability issues. Together with the Vice President, Sustainable Development, the business units and selected internal technical representatives are responsible for setting operational sustainability goals and assessing progress, including energy efficiency across all areas of our business.

The Environment, Health, Safety and Sustainable Development Committee of the Board of Directors meets quarterly to review 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 emissions reduction plans given legal, industry and community standards. Management systems are maintained by the committee to implement such policies and ensure compliance with them.

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. To signify agreement with the Copenhagen Accord, 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, the Copenhagen Accord does not contain any binding commitments for reducing CO_2 emissions, nor does it include any discussion of compliance mechanisms. The other focal point of the Copenhagen Accord was a commitment by all major emitting countries to provide funding, including $30 billion from 2010 to 2012, for developing countries for climate change mitigation and adaptation.

During COP 17 in Durban, South Africa, several nations, including Canada, Japan and Russia, announced their intentions not to commit to a second period under the Kyoto Protocol; however, Canada reaffirmed commitments for GHG reductions and funding under the Copenhagen Accord.

Canadian Federal GHG Regulations

The Canadian federal government has started to address 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 thermal 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 that 2% of diesel supply come from bio-diesel. The Canadian federal government has stated that it will align its approach to GHG regulation with the approach of the U.S. and, in 2011, entered into preliminary discussions with the Canadian oil and gas industry on proposed regulations for the sector.

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 GHG 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 July 2007, pursuant to the *Specified Gas Emitters Regulation* enacted under the *Climate Change and Emissions Management Act (Alberta)*, facilities emitting more than 100,000 tonnes of CO_2 equivalent (CO_{2e}) per year are subject to intensity limits (GHG emissions per unit of production) and are required to reduce their intensity limits by 12% from an established baseline. Five facilities operated by Suncor in Alberta (Oil Sands Base plants, MacKay River operations, Firebag operations, the Edmonton refinery and the Hanlan gas processing plant) are subject to, and continue to comply with, this legislation. In 2010, the total cost to comply with the Alberta regulations was approximately $11 million. Compliance in 2010 was achieved through reduced emissions per unit of production, purchase and retirement of offset credits and payments to Alberta's Climate Change and Emissions Management Fund (Alberta Technology Fund). In March 2012, Suncor expects to file compliance reports that show what actions the company took during 2011 to demonstrate that each facility either met its intensity target or took action to offset its emissions intensity. Compliance options available to Suncor include reducing emissions, using Alberta-sanctioned

offset projects, or contributing to the Alberta Technology Fund. For the compliance period of January 1 to December 31, 2011, the compliance costs to Suncor are estimated to be between $10 million and $15 million, based on a cost of $15/tonne, which was in effect for 2011. Future costs may be subject to change, given that late in 2011, the *Specified Gas Emitters Regulation* was amended by the Government of Alberta, such that the contribution cost is no longer specified at the $15/tonne level. Instead, the contribution cost will be established by Order of the Minister.

Several Canadian provinces (including British Columbia, Ontario and Quebec) are members of the Western Climate Initiative (WCI), a multi-jurisdictional partnership created in 2007 to address climate change. Effective January 1, 2010, the *Greenhouse Gas Reduction Act (Cap and Trade)* enabled the British Columbia government to participate in the trading system being implemented by the WCI. Draft regulations, as well as offset regulations, have been posted by the British Columbia Climate Action Secretariat, but have yet to be finalized. The Province of British Columbia also enacted a carbon tax in 2008, which began at $10/tonne of CO_{2e} and escalates at $5/tonne per year until 2012 when it reaches its maximum of $30/tonne. This carbon tax is carbon neutral, in that revenues are recycled back to taxpayers via tax reductions and is applied on consumption. Under these regulations, Suncor's natural gas production and gathering facilities in B.C. are classified as one facility, which in aggregate exceed the 100,000 tonne threshold that requires the reporting of emissions to be verified by third parties. Suncor's refined product distribution terminals in B.C. are required to report emissions, but do not exceed the threshold that requires third-party verification.

In 2007, Quebec introduced a tax on hydrocarbon production and imports, with the revenues going into a Green Fund, to support transit and other emissions-reducing projects. This tax impacts Suncor's refining and marketing activities in the province.

During 2011, Quebec introduced regulations for a cap-and-trade system for GHG emissions. This system required Suncor to register as an emitter because the Montreal refinery produces more than 25,000 tonnes of CO_{2e} per year. Emitters must verify their emissions during specified compliance periods (the first period commencing January 1, 2013 and ending December 31, 2014), and must either reduce their emissions or purchase eligible compliance mechanisms to cover their emissions above a specified cap. Quebec is responsible for setting the cap for the province and allocating allowances to emitters in its jurisdiction. Quebec has deemed 2012 a transition year, with no cap imposed. Allowances are fungible across the WCI, such that Quebec-issued allowances can be bought and sold with the larger trading system, which currently consists solely of Quebec and California. It is anticipated that the Green Fund will eventually be merged with the cap-and-trade system.

Ontario is also a member of the WCI and implemented mandatory reporting regulations beginning with 2010 emissions, but has delayed action on any further GHG emissions regulations.

U.S. GHG Regulations

Several attempts were made during the past two years to enact GHG legislation in the United States, none of which made it through both the Senate and the House. In an effort to build a green economy, the President has opted to push for a clean energy standard that would reduce GHG emissions from the power sector and increase the use of cleaner sources of energy, including natural gas, nuclear power and "clean" coal. In addition, the President is pressing ahead by endorsing the U.S. Environmental Protection Agency (EPA) to regulate GHG emissions under the Clean Air Act. The implications of industry being regulated under the EPA and the timing of such regulation 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, which includes Suncor's Commerce City refinery.

The EPA has also mandated Renewable Fuel Standards 2, which encourages 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.

The State of California has passed AB32, which provides for a Low Carbon Fuel Standard (LCFS). In December 2011, the United States District court ruled against California's LCFS, stating that it was in violation of the Commerce Clause of the United States Constitution. Suncor does not actively market into California; however, there were two aspects of the ruling that are pertinent to Suncor – the discrimination against out-of-state producers (in this case, those that are reliant on coal-fired electrical power generation for the production of ethanol), and the attempt by California to use a life-cycle analysis as the basis for the LCFS that includes exploration and production processes outside of the State's jurisdiction. The State of California has stated that it will appeal the ruling. The outcome of this appeal is anticipated during 2012.

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.

Land Use

In 2011, the Government of Alberta issued its draft Lower Athabasca Regional Plan (LARP), which covers the Lower Athabasca Region and includes Suncor's Oil Sands segment. The LARP, developed as part of the Land-Use Framework under the Alberta Land Stewardship Act, identifies new conservation areas, as well as management frameworks for the quality of air, surface water and groundwater. The new conservation areas do not overlap any of Suncor's leases. The management frameworks formalize a number of regulatory tools that are already used by the government to manage environmental aspects of oil sands development, and may require Suncor to have greater participation in the evaluation of environmental issues. The frameworks include the following:

- **Air.** The framework is designed to maintain flexibility and to manage cumulative effects of development on air quality within the region, setting triggers and limits for nitrogen dioxide (NO_2) and sulphur dioxide (SO_2). The framework includes ambient air quality triggers and limits. Management actions are required when triggers are exceeded or limits are reduced.

- **Surface water.** The framework builds on, but does not replace, existing provincial legislation and policy on water quality, and provides a framework in which to monitor and manage long-term, cumulative changes in water quality within the lower Athabasca River. The framework includes quality limits and triggers for various indicators, based on existing Alberta, Canadian Council of Ministers of the Environment, Health Canada and U.S. EPA guidelines. Management actions are required when triggers or limits are reached.

- **Groundwater.** The framework aims to manage non-saline groundwater resources in a sustainable manner and protect resources from contamination and over-use. The framework aims to ensure timely detection of key changes to indicators and describes the management response that will be initiated if triggers or limits, including site-specific measures, are reached.

Reclamation and Tailings

In February 2009, the ERCB released Directive 74 *Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes* . The directive establishes performance criteria for tailings operations and requirements for the approval, monitoring and reporting of tailings ponds and plans. Suncor is in the final stages of its transition from a consolidated tailings management plan to TRO_{TM} operations, which is Suncor's new tailings management strategy. TRO_{TM} was approved by the ERCB in June 2010. Suncor's mine plan is designed to facilitate the implementation of TRO_{TM} through providing space for the drying of tailings and ensuring adequate and timely storage capacity for extraction tailings from both the Millennium and NSE mines.

The Government of Alberta also has in place the Mine Financial Security Program (MFSP), which holds oil sands miners responsible for all aspects of the suspension, abandonment, remediation and surface reclamation work at their mine sites, and custody of the site until a reclamation certificate has been issued by the government. The MFSP requires a base amount of security for each project in the form of letters of credit, which would provide the funds necessary to safely secure the site. Additional security is required under other conditions, such as failure to meet current reclamation plans or when the estimated remaining production life of the mine reaches certain levels; however, Suncor has not been required to provide any additional security. In 2011, the Government of Alberta finalized changes to the MFSP, but these changes did not significantly impact Suncor's existing or near-term requirements for providing additional security.

Hydraulic Fracturing

Hydraulic fracturing is the process of pumping a fluid or a gas under pressure down a well, which causes the surrounding rock to crack or fracture. The fluid, typically consisting of water, sand, chemicals and other additives, flows into the cracks where the sand remains to keep the cracks open and allow natural gas or liquids to be recovered. Fracturing fluids are produced back to the surface through the wellbore and are stored for reuse or future disposal in accordance with regional regulations, which may include injection into underground wells.

The Government of Canada manages use of chemicals through its Chemical Management Plan and New Substances Program. Some provinces require the details of fracturing fluids to be submitted to regulators. In Alberta, the ERCB requires that all fracturing operations submit regarding the quantity of fluids and additives.

While this process has been in use and improved upon for many generations, the proliferation of fracturing in recent years to access hydrocarbons in unconventional reservoirs, such as shale formations, has raised concerns about the interaction of fracturing fluids with the water supply. In the U.S., the process is regulated by state and local governments, but the EPA is considering undertaking a broad study as it pertains to the national Clean Water Act. Any U.S. rules on hydraulic fracturing could influence other jurisdictional regulation and force oil and gas companies, including Suncor, to cease using the process or to add pollution control technology to their operations. The implications of this activity being regulated under the EPA are as yet unknown.

Industry Collaboration Initiatives

For areas of environmental concern, the need for energy companies to increase collaboration with each other, and with their respective stakeholders, is a particularly critical issue for the oil sands industry. As part of the Oil Sands Leadership Initiative (OSLI), Suncor is working closely with like-minded companies to make tangible improvements to environmental, social and economic performance in the oil sands industry. These companies have come together to pool financial resources and expertise. In 2010, members of OSLI investigated new technologies to improve industry-wide reuse of tailings waste water and to make oil recovery more energy efficient, while also engaging new stakeholders and opinion leaders.

In addition, Suncor and six other oil sands companies announced the creation of the Oil Sands Tailings Consortium in December 2010, and agreed to work together in a unified effort to advance tailings management. Each company has pledged to share its existing tailings research and technology and to remove barriers to collaborating on future tailings research and development. In turn, the companies are committing to future research investments to further accelerate tailings technology advances.

Suncor's Sustainability Commitment

Suncor remains committed to reducing overall GHG emissions 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 OSLI. For further information, please see our Sustainability Report at www.suncor.com.

RISK FACTORS

The company is committed to a proactive program of enterprise risk management intended to enable decision-making through consistent identification of risks inherent to the assets and activities of Suncor. The company's enterprise risk committee (ERC), comprised of senior representatives from business and functional groups across Suncor, oversees entity-wide processes to identify, assess and report on the company's principal risks. A principal risk is an exposure that has the potential to materially impact the ability of one of our businesses or functions to meet or support a Suncor objective.

Commodity Price Volatility

Our financial performance is closely linked to prices for crude oil in our upstream business and prices for refined petroleum products in our downstream business, and, to a lesser extent, to natural gas prices in our upstream business, where natural gas is both an input and output of production processes. The values for all of these commodity prices can be influenced by global and regional supply and demand factors.

Crude oil prices are also affected by, among other things, global economic health and global economic growth (particularly in emerging markets), political developments, compliance or non-compliance with quotas imposed on OPEC members, access to markets for crude oil and weather. These factors impact the various types of crude oil and refined products differently and can impact differentials between light and heavy grades of crude oil (including blended bitumen), and between conventional and synthetic crude oil.

Suncor anticipates higher production of non-upgraded bitumen in future years, due mainly to expansion at Firebag. Due to its low viscosity, bitumen is blended with a light diluent or SCO and sold as a heavy crude oil. The markets for heavy crude are more limited than those for light crude, making them more susceptible to supply and demand changes. Heavy crude oil receives lower market prices than light crude, due principally to the lower quality and value of the refined product yield, and the higher cost to transport the more viscous product on pipelines. The price differential between light crude and WCS is particularly important for Suncor. WCS is a pool of heavy crude oil and blended bitumen production from Western Canada. The market price for WCS is influenced by regional supply and demand factors, including the availability and price of diluent, and by the availability and cost of accessing primary markets through pipeline systems. Future price differentials are uncertain and widening light/heavy differentials could have a negative impact on our business, especially price realizations for bitumen that Suncor is unable to upgrade.

Refined petroleum product prices and refining margins are also affected by, among other things, crude oil prices, the availability of crude oil and other feedstocks, levels of refined product inventories, regional refinery availability, marketplace competitiveness, and other local market factors.

Natural gas prices in North America are affected primarily by supply and demand, and by prices for alternative energy sources. All of these factors are beyond our control and can result in a high degree of price volatility.

Commodity prices and refining margins have fluctuated widely in recent years. Given the recent global economic uncertainty, we expect continued volatility and uncertainty in commodity prices in the near term, with the possibility that crude oil and

refined petroleum products prices could revert to the low levels experienced in 2008 and 2009. A prolonged period of low prices could affect the value of our upstream and downstream assets and the level of spending on growth projects, could result in the curtailment of production on some properties and include an impairment of carrying value. Accordingly, low commodity prices, particularly for crude oil, could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Government Policy

Suncor operates under federal, provincial, state and municipal legislation in numerous countries. The company is also subject to regulation and intervention by governments in oil and gas industry matters, such as land tenure, royalties, taxes (including income taxes), government fees, production rates, environmental protection controls, safety performance, the reduction of GHG and other emissions, the export of crude oil, natural gas and other products, the company's interactions with foreign governments, the awarding or acquisition of exploration and production rights, oil sands leases 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.

Changes in government policy or regulation have a direct impact on Suncor's business, financial condition, results of operations and cash flow, as evidenced by such initiatives as the Alberta government's royalty review program in 2007, and, more recently, by trade sanctions in Libya and Syria imposed by Canadian and other international governments, and increased production taxes in the U.K. Changes in government policy or regulation can also have an indirect impact on Suncor, such as opposition to new North American pipeline systems, such as Keystone XL, or incrementally over time, through increasingly stringent environmental regulations or unfavourable income tax and royalty regimes. The result of such changes can also lead to additional compliance costs and staffing and resource levels, and also increase exposure to other principal risks of Suncor, including environmental or safety non-compliance and permit approvals.

Environmental Regulation

Changes in environmental regulation could have a material adverse effect on our business, financial condition, results of operations and cash flow by impacting the demand, formulation or quality of our products, or by requiring increased capital expenditures or distribution costs, which may or may not be recoverable in the marketplace. The complexity and breadth of changes in environmental regulation make it extremely difficult to predict the potential impact to Suncor. 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. Failure to comply with environmental regulation may result in the imposition of significant 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.

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;
- The use of hydraulic fracturing to assist in the recovery and production of oil and natural gas;
- Issues relating to land reclamation, restoration and wildlife habitat protection;
- Reformulated gasoline to support lower vehicle emissions;
- U.S. state or federal calculation and regulation of fuel life-cycle carbon content; and
- Regulation or policy by foreign governments or other organizations to limit purchases of oil produced from unconventional sources, such as the oil sands.

Climate Change Regulation

Future laws and regulations may impose significant liabilities on a failure to comply with their requirements; however, Suncor expects the cost of meeting new environmental and climate change regulations will not be so high as to cause material disadvantage to the company or material damage to its competitive positioning. While it currently appears 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.

As part of our ongoing business planning, Suncor assesses potential costs associated with CO_2 emissions in our evaluation of future projects, based on our current understanding of pending and possible GHG 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. In the future, 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 a price range of $15-$45 per tonne of CO_2 equivalent as a base case, applied against a range of regulatory policy options and price sensitivities.

Although Suncor does not actively market into California, the implications of other states or countries adopting similar LCFS legislation could pose a significant barrier to our exports of oil sands crude if the importing jurisdictions do not acknowledge efforts undertaken by the oil sands industry to meet the emissions intensity reductions legislated by the Government of Alberta.

In general, there remains uncertainty around the outcome and impacts of proposed or potential future climate change and other related environmental regulation. The Canadian federal government has gone on record as saying that it will align GHG emissions legislation with the U.S. Although it remains unclear what approach the U.S. will take, or when, the Canadian federal government has indicated a preference for a sector specific approach; however, it is unclear what form any regulation will take for the oil and gas sector, and what type of compliance mechanisms will be available to large emitters. At this time, the company does not believe it is possible to predict the nature of any requirements or the impact on Suncor's business, financial condition, results of operations and cash flow. The impact of developing regulations cannot be quantified at this time given the current lack of detail on how systems will operate.

Land Reclamation

There are risks associated specifically with our ability to reclaim tailings ponds containing mature fine tailings with TRO $_{TM}$ or other methods and technologies. Suncor expects that TRO_{TM} will help the company reclaim existing tailings ponds by reducing tailings. The success of TRO $_{TM}$ or any other methods or technology and the time to reclaim tailings ponds could increase or decrease our decommissioning and restoration cost estimates. Our failure or inability to adequately implement our reclamation plans, including our planned implementation of TRO_{TM}, could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow. In recent years, Suncor has increased collaboration with other participants in the oil sands industry to share technology and knowledge and to research alternative methods for tailings management.

Royalties

Royalties can be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs, by changes to existing legislation or PSCs, and by results of regulatory audits of prior year filings and other unexpected events. Some of the issues where settlement with regulatory bodies may cause royalties expense or royalties payable to differ materially from provisions currently recorded include:

- For Suncor's mining operations (not including Syncrude), the BVM is based on the terms of Suncor's RAA, which we believe places certain limitations on the interim BVM as recently enacted, which modified the BVM for additional quality and transportation adjustments. For the years 2009 to 2010, Suncor filed non-compliance notices with the Alberta government, citing that reasonable quality adjustments in the determination of the Suncor BVM were not considered by the Alberta government as permitted by Suncor's RAA. Suncor has also filed with the Alberta government a Notice of Commencement of Arbitration under the Suncor RAA. The owners of the Syncrude joint venture have also filed a non-compliance notice in respect of the determination of the bitumen value under its 2008 agreements with the Alberta government.

- Suncor has also appealed the disallowance of certain costs under the New Royalty Framework in Alberta and certain costs under royalty agreements in Newfoundland and Labrador, such as insurance premiums.

The final determination of these matters may have a material impact on royalties payable to the respective governments and on the company's royalties expense.

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 and other uncertainties arising from foreign government sovereignty over the company's international operations, 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;

- Compliance with existing and emerging anti-corruption laws, including the Foreign Corrupt Practices Act of the United States, the Corrupt Foreign Officials Act of Canada and the United Kingdom Bribery Act;

- Renegotiation of contracts with governmental entities and quasi-governmental agencies;
- Changes in laws and policies governing operations of foreign-based companies; and
- Economic and legal sanctions (such as restrictions against countries experiencing political violence, or countries that other governments may deem to sponsor terrorism).

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. In addition, 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.

In 2011, operations in both Libya and Syria were suspended as a result of the outbreak of political unrest and the resulting sanctions imposed by international governments. Discussions with the Libyan authorities continue on the status of existing contract terms, including production volumes and exploration commitments. There is still sufficient unpredictability underlying operations in this region, including the ramp up of production, the sustainability of current production rates and the extent of damage to the company's assets, which has not yet been fully assessed. As a result, there is no assurance that production will return to previous levels or continue at current levels.

In response to sanctions and escalating political unrest in Syria, Suncor declared force majeure in December 2011, withdrew its expatriate staff and stopped recording production from Syria. Suncor's assessment of the situation as at December 31, 2011 did not require the company to record an impairment charge against its assets in Syria; however, should the current situation persist or worsen, such that Suncor is unable to resume operations in the near term, the company believes its assets in Syria could be impaired in the future. There is no assurance as to when Suncor's production from Syrian assets will resume or return to previous levels. Suncor's operations in Syria represented approximately 3% of the company's consolidated net earnings and 3% of the company's cash flow from operations in 2011. The carrying value of Suncor's net assets in Syria at December 31, 2011 was approximately $900 million.

The impact that future potential terrorist attacks, regional hostilities or political violence may have on the oil and gas industry, and on our operations in particular, is not known at this time. This uncertainty may affect operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly crude oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or collateral damage of, an act of terror, political violence or war. We may be required to incur significant costs in the future to safeguard our assets against terrorist activities or to remediate potential damage to our facilities. There can be no assurance that we will be successful in protecting ourselves against these risks and the related financial consequences.

EHS Regulatory Non-Compliance

The company is required to comply with a large number of EHS regulations under a variety of Canadian, U.S., U.K. and other foreign, federal, provincial, territorial, state and municipal laws and regulations, as described in the Industry Conditions – Environmental Regulation section of this AIF. Failure to comply with these regulations may result in the imposition of fines and penalties, censure, liability for cleanup costs and damages, and the loss of important licences and permits, which could also have a material adverse effect on our business, financial condition, results of operations and cash flow. Compliance can be affected by the loss of skilled staff, inadequate internal processes and compliance auditing.

Operational Outages and Major Environmental or Safety Incidents

Each of our primary operating businesses – Oil Sands, Exploration and Production, and Refining and Marketing – demand significant levels of investment in the design, operation and maintenance of facilities, and, therefore, carry the additional economic risk associated with operating reliably or enduring a protracted operational outage. These businesses also carry the risks associated with environmental and safety performance, which is closely scrutinized by governments, the public and the media, and could result in a suspension of or inability to obtain regulatory approvals and permits, or, in the case of a major environmental or safety incident, civil suits or charges against the company.

Generally, our operations are subject to operational hazards and risks such as fires, explosions, blow-outs, power outages, severe winter climate conditions, and the migration of harmful substances such as oil spills, gaseous leaks, or a release of tailings into water systems, any of which can interrupt operations or cause personal injury or death, or damage to property, equipment, the environment, and information technology systems and related data and control systems.

The reliable operation of production and processing facilities at planned levels and our ability to produce higher value products can also be impacted by failure to follow operating procedures or operate within established operating parameters, equipment failure through inadequate maintenance, unanticipated erosion or corrosion of facilities, manufacturing and engineering flaws, and labour shortage or interruption. We are also subject to operational risks such as sabotage, terrorism, trespass, theft and malicious software or network attacks.

The efficient operation of our business is dependent on computer hardware and software systems. Information systems are vulnerable to security breaches by computer hackers and cyberterrorists. We rely on industry accepted security measures and technology to securely maintain confidential and proprietary information stored on our information systems. However, these measures and technology may not adequately prevent security breaches. In addition, the unavailability of the information systems or the failure of these systems to perform as anticipated for any reason could disrupt our business and could result in decreased performance and increased operating costs, causing our business and results of operations to suffer. Any significant interruption or failure of our information systems or any significant breach of security could adversely affect our business and results of 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. Disruptions in pipeline service could adversely affect commodity prices, Suncor's price realizations, refining operations and sales volumes, or limit our ability to deliver production. These interruptions may be caused by the inability of the pipeline to operate or by the oversupply of feedstock into the system that exceeds pipeline capacity. There can be no certainty that short-term operational constraints on pipeline systems arising from pipeline interruption and/or increased supply of crude oil will not occur. In addition, planned or unplanned shutdowns or closures of our refinery customers may limit our availability to deliver feedstock. All of these events could have negative implications on sales and cash from operating activities.

For Suncor's Oil Sands operations, mining oil sands ore, extracting bitumen from mined ore, producing bitumen through in situ methods, 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. 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, Suncor has two upgrader facilities that include three secondary upgrading units, which provide us with the flexibility to conduct periodic planned maintenance events on one facility while continuing production from the other.

For Suncor's upstream businesses, there are risks and uncertainties associated with drilling for oil and natural gas, the operation and development of such properties and wells (including encountering unexpected formations, pressures, ore grade qualities, or the presence of H_2S), premature declines of reservoirs, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, other accidents, and pollution and other environmental risks.

Our Exploration and Production 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 and other extreme weather conditions. 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 consequence of catastrophic events, such as blow-outs, occurring in offshore operations can be more difficult and time-consuming to remedy. 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. Successful remediation of these events may be adversely affected by the water depths, pressures and cold temperatures encountered in the ocean, shortages of equipment and specialists required to work in these conditions, or the absence of appropriate technology to resolve the event. Damage to the environment, particularly through oil spillage or extensive, uncontrolled fires or death, could result from these offshore operations. Our offshore operations could also be affected by the actions of our contractors and agents that could result in similar catastrophic events at their facilities, or could be indirectly affected by catastrophic events occurring at other third-party offshore operations. In either case, this could give rise to liability, damage to our equipment, harm to individuals, force a shutdown of our facilities or operations, or result in a shortage of appropriate equipment or specialists required to perform our planned operations.

In particular, East Coast Canada operations can be impacted by winter storms, pack ice, icebergs and fog. 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. During the spring, pack ice and icebergs drifting in the area of our offshore facilities have resulted in precautionary shut in of FPSO production and drilling delays. In late spring and early summer, fog also impacts our ability to transfer personnel to the offshore facilities by helicopter.

Our Refining and Marketing operations are subject to all of the risks normally inherent in the operation of refineries, terminals, pipelines and other distribution facilities and service stations, including loss of product, slowdowns due to equipment failures, unavailability of feedstock, price and quality of feedstock or other incidents.

Losses resulting from the occurrence of any of these risks identified above could have a material adverse effect on Suncor's 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. It is possible that our insurance coverage will not be sufficient to address the costs arising out of the allocation of liabilities and risk of loss arising from offshore operations. Suncor also has a captive insurance entity to provide additional business interruption coverage for potential losses.

Project Execution and Partner Risk

There are certain risks associated with the execution of our major projects and the commissioning and integration of new facilities within our existing asset base, the occurrence of which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Project execution risk consists of three related primary risks:

- Engineering – a failure in the specification, design or technology selection;
- Construction – a failure to build the project in the approved time and at the agreed cost; and
- Commissioning and start-up – a failure of the facility to meet agreed performance targets, including operating costs, efficiency, yield and maintenance costs.

Management believes the execution of major projects presents issues that require prudent risk management. Suncor may provide cost estimates for major projects at the conceptual stage, prior to commencement or completion of the final scope design and detailed engineering necessary to reduce the margin of error of such cost estimates. Accordingly, actual costs can vary from estimates, and these differences can be material. Project execution can also be impacted by:

- Failure to comply with Suncor's project implementation model;
- The availability, scheduling and cost of materials, equipment and qualified personnel;
- The complexities associated with integrating and managing contractor staff and suppliers in a confined construction area;
- Our ability to obtain the necessary environmental and other regulatory approvals;
- 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.

Other entities operate a portion of the assets in which Suncor has ownership interests. Suncor's dependence on its partners – the operator and other working interest owners for these assets – and its limited ability to influence operations and associated costs could materially adversely affect Suncor's business, financial condition, results of operations and cash flow. The success and timing of Suncor's activities on assets operated by others depend upon a number of factors that are outside of Suncor's control, including the timing and amount of capital expenditures, the timing and amount of operational and maintenance expenditures, the operator's expertise, financial resources and risk management practices, the approval of other participants, and the selection of technology.

These partners may have objectives and interests that do not coincide with and may conflict with Suncor's interests. Major capital decisions affecting jointly owned assets may require agreement among the partners, while certain operational decisions may be made solely at the discretion of the operator of the applicable assets. While the partners generally seek consensus with respect to major decisions concerning the direction and operation of the assets, no assurance can be provided that the future demands or expectations of either party relating to such assets will be met satisfactorily or in a timely manner. Failure to satisfactorily meet demands or expectations by either party may affect our participation in the operation of such assets, our ability to obtain or maintain necessary licences or approvals, or the timing for undertaking various activities.

Corporate Reputation

The public perception of integrated oil and gas companies and their operations may pose issues related to development and operating approvals or market access for products, which may have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Development of the oil sands has figured prominently in recent political, media and activist commentary on the subjects of pipeline transportation, climate change, GHG emissions, water usage and environmental damage, which may directly or indirectly harm the profitability of our current oil sands projects and the viability of future oil sands projects in a number of ways, including:

- Creating significant regulatory uncertainty that challenges economic modelling of future projects and potentially delays sanctioning;
- Motivating extraordinary environmental and emissions regulation of those projects by governmental authorities that could result in changes to facility design and operating requirements, thereby potentially increasing the cost of construction, operation and abandonment; and

- Compelling legislation or policy that limits the purchase of crude oil produced from the Athabasca oil sands by governments and other institutional consumers that, in turn, limits the market for this crude oil and reduces its price.

Concerns such as those raised above may also harm our corporate reputation and limit our ability to transport our products or access land and joint venture opportunities in other jurisdictions throughout the world. Investors may respond by applying a discount to Suncor's shares, thereby diminishing the company's value, or may hinder Suncor in its ability to influence government policy.

Permit Approvals

Before proceeding with most major projects, including significant changes to existing operations, Suncor must obtain various federal, provincial or state permits and regulatory approvals. Suncor must also obtain licences to operate certain assets. These processes can involve, among other things, stakeholder consultation, environmental impact assessments and public hearings, and may be subject to conditions, including security deposit obligations and other commitments. Suncor can also be indirectly impacted by a third party's inability to obtain regulatory approval for a shared infrastructure project.

Failure to obtain regulatory approvals, or failure to obtain them on a timely basis or 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 Suncor's business, financial condition, results of operations and cash flow.

Skills and Resource Shortage

The successful operation of Suncor's businesses and our ability to expand operations will depend upon the availability of, and competition for, skilled labour and materials supply. There is a risk that we may have difficulty sourcing the required labour for current and future operations. The risk could manifest itself primarily through an inability to recruit new staff without a dilution of talent, to train, develop and retain high quality and experienced staff without unacceptably high attrition, and to satisfy an employee's work/life balance and desire for competitive compensation. The labour market in Alberta is particularly tight due to the growth of the oil sands industry and higher crude oil prices. The increasing age of our existing workforce adds further pressure to this situation. Materials may also 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.

Change Capacity

In order to achieve Suncor's business objectives, the company must operate efficiently, reliably and safely, and, at the same time, deliver growth and sustaining projects safely, on budget and on schedule. The ability to balance these two sets of objectives is critically important to Suncor to deliver value to shareholders and stakeholders. These objectives demand a large number of improvement initiatives that compete for resources, and may negatively impact the company should there be inadequate screening of project requests or consideration of the cumulative impacts of prior and parallel initiatives on people, processes and systems. There is a risk that these objectives may exceed Suncor's capacity to adopt and implement change.

Cost Management

Production from oil sands through mining, upgrading and in situ recovery is, relative to most major conventional hydrocarbon reserves, a higher cost resource to develop and produce. There is also a perception among many stakeholders that the oil sands industry, including Suncor, has little ability to control costs. Suncor is exposed to the risks of growing or uncontrollable operating costs, which could reduce profitability and cash flow that might otherwise be directed towards growth or dividends, and major project capital costs, which could constrain Suncor's ability to execute high quality projects that deliver lower operating costs. Factors contributing to these risks include, but are not limited to, the skills and resource shortage, the long-term success of existing and new in situ technologies, and the geology and reserves characterization of in situ reserves that can lead to higher SORs and lower production.

Exchange Rate Fluctuations

Our audited Consolidated Financial Statements are presented in Canadian dollars. The majority of Suncor's revenues from the sale of oil and natural gas are based on prices that are determined by, or referenced to, U.S. dollar benchmark prices, while the majority of Suncor's expenditures are realized in Canadian dollars. The company also holds substantial amounts of U.S. dollar debt. Suncor's results, therefore, can be affected significantly by the exchange rates between the Canadian dollar and the U.S. dollar. The company also undertakes operations administered through international subsidiaries, and so, to a lesser extent, Suncor's results can be affected by the exchange rates between the Canadian dollar and the euro, and the Canadian dollar and the British pound. These exchange rates may vary substantially and may give rise to favourable or unfavourable foreign currency exposure, which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Reliance on Key Personnel

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

Labour Relations

Hourly employees at our Oil Sands facilities near Fort McMurray, Alberta, all of our refineries, certain of our lubricants operations, certain of our terminalling and distribution operations, and our Terra Nova FPSO are represented by labour unions or employee associations. Approximately 36% of our employees are members of the Communications, Energy and Paperworkers Union. Any work interruptions involving our employees, contract trades utilized in our projects or operations, or any joint venture facilities operated by another entity could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

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.

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 upgraded production of synthetic crude oil from bitumen – all of which may vary considerably from actual results. The accuracy of any reserves and resources estimates is a matter of interpretation and judgment and is a function of the quality and quantity of available data, which may have been gathered over time.

Reserves and resources estimates are based upon a geological assessment, including drilling and laboratory tests. Mining reserves and resources estimates also consider production capacity and upgrading yields, mine plans, operating life and regulatory constraints. In Situ reserves and resources estimates are also based upon the testing of core samples and seismic operations, trends of well performance, and demonstrated commercial success of in situ processes. 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.

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.

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 the risk of recovery, prepared by different engineers or by the same engineers at different times, may vary.

Need to Replace Conventional Reserves

In our Exploration and Production business, conventional oil and natural gas reserves and future production are highly dependent on the successful discovery or acquisition of additional reserves, without which production rates will decline as reserves are depleted. Decline rates will vary with the nature of the reservoir, the life cycle of the well and other factors, and 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/or 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 constrained. In addition, the long-term performance of the Exploration and Production business is dependent on our ability to consistently and competitively find and develop low cost, high quality reserves that can be brought on-stream economically.

In Situ Recovery and Other 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 application of new technologies may differ from simulated or test environments. The success of projects incorporating new technologies, such as in situ technology, cannot be assured.

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 in the industry, 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.

Energy Trading and Risk Management Activities and the Exposure to Counterparties

The nature of energy trading and risk management activities, which may make use of hedging and derivative financial instruments, creates exposure to significant financial risks, which include, but are not limited to, the following:

- 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;
- Loss as a result of human error or deficiency in our systems or controls; and
- Loss as a result of contracts being unenforceable or transactions being inadequately documented.

In the normal course of business, the company enters into contractual relationships with counterparties in the energy industry and other industries, including counterparties for interest rate, foreign exchange and commodity hedging arrangements. If such counterparties do not fulfil their contractual obligations, the company 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.

Suncor has adopted a Trading Risk Management Policy (the Trading Policy), which requires all trading activities to occur in the group responsible for trading, so that trading risks can be properly monitored, controlled and reported. The Board has set the trading commodities, trading term limits, value-at-risk limits and stop-loss limits under the Trading Policy. Any changes to the foregoing require Board approval. The Board reviews and monitors Suncor's compliance with the Trading Policy through the Audit Committee, which receives a quarterly report that summarizes Suncor's trading activities and provides an assessment of Suncor's financial exposure to risk from these activities.

To reduce exposure to unfavourable movements in commodity prices, interest rates and foreign exchange rates, the company also periodically enters into contracts involving derivative financial instruments. 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.

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 Suncor's business, financial condition, results of operations and cash flow.

Control Environment

Based on their evaluation as of December 31, 2011, 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, 2011, 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, 2011 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.

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 company's Board considers relevant. There can be no assurance that we will continue to pay dividends in the future, at current levels, or at all.

Interest Rate Risk

We are exposed to fluctuations in short-term Canadian and U.S. interest rates as Suncor maintains a portion of its debt capacity in revolving and floating rate bank facilities and commercial paper, and invests surplus cash in short-term debt instruments. We are also exposed to interest rate risk when debt instruments are maturing and require refinancing, or when new debt capital needs to be raised.

Capital Markets

Suncor expects that future capital expenditures will be financed out of cash generated from operations and borrowings. This ability is dependent on, among other factors, commodity prices, 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. The 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. To the extent that external sources of capital become limited or unavailable or available on unfavourable terms, our ability to make capital investments and maintain existing properties may be constrained, and, as a result, Suncor's business, financial condition, results of operations and cash flow may be materially adversely affected.

At December 31, 2011, we had approximately $4.4 billion of unused credit available under bank credit facilities. Based on current cash and cash equivalents balances and expected cash from operations, we believe that we have sufficient funds available to fund our planned capital expenditures for 2012. If cash flow from operations is lower than expected, if capital expenditures in 2012 exceed current estimates, or if we incur major unanticipated expenses related to the development or maintenance of our existing assets, Suncor may need to re-evaluate its capital program or 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. Choosing to seek additional capital might adversely affect our credit ratings. Either of these events could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Issuance of Debt and Debt Covenants

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 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 an unfavourable cost 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 credit ratings, which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Suncor currently has $5.8 billion in credit facilities, the majority of which matures in 2016, with the remainder maturing in 2013 or on demand. At December 31, 2011, Suncor's total debt was $10.8 billion. 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, capital structure and/or dividend policy to comply with covenants under the credit facilities. If Suncor does not comply with the covenants under its credit facilities and debt securities, repayment could be required and/or the company's access to capital could be restricted or only be available on unfavourable terms, all of which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Suncor's debt instruments are rated by various credit rating agencies. These ratings affect Suncor's ability to gain access to reasonably priced debt financing. If any of Suncor's credit rating agencies downgrade Suncor's debt instruments, it may restrict Suncor's ability to issue debt and may also increase the cost of borrowing, including under existing credit facilities.

Rating agencies regularly evaluate the company and our subsidiaries. Their ratings of our long-term and short-term debt are based on a number of factors, including our financial strength, as well as factors not entirely within our control, including conditions affecting the oil and gas industry generally, and the wider state of the economy. We cannot be assured that one or

more of our credit ratings will not be downgraded. Our borrowing costs and ability to raise funds are directly impacted by our credit ratings. In addition, credit ratings may be important to customers or counterparties when we compete in certain markets and when we seek to engage in certain transactions, including transactions involving over-the-counter derivatives.

It is our objective to maintain high quality credit ratings appropriate for our business activities. A credit-rating downgrade could potentially limit our access to private and public credit markets and increase the costs of borrowing under existing facilities. A reduction in our credit ratings also could have a significant impact on certain trading revenues, particularly in those businesses where counterparty creditworthiness is critical. It could trigger collateralization requirements related to physical and financial derivative liabilities with certain marketing counterparties and facility construction contracts. The occurrence of any of the foregoing could adversely affect our ability to execute portions of our business strategy and could have a material adverse effect on our liquidity and capital position.

Competition

The global petroleum industry is highly competitive in many 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 refined petroleum products. We compete in virtually every aspect of our business with other energy companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers. We believe the primary competition for our crude oil production is other major international oil and natural gas producers and integrated companies.

For Suncor's Oil Sands segment, 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. During recent years, a global focus on the oil sands through increasing industry consolidation that has created competitors with financial capacity has significantly increased the supply of bitumen, SCO and heavy crude oil in the marketplace and increased land values and the number of new oil sands leases available. The impact of this level of activity on regional infrastructure, including pipelines, has placed stress on the availability and cost of all resources required to build and run new and existing oil sands operations.

For Suncor's Refining and Marketing businesses, 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.

Land Claims

First Nations people have claimed Aboriginal title and rights to portions of Western Canada. In addition, First Nations people have filed claims against industry participants relating in part to land claims, which may affect our business. At the present time, we are unable to assess the effect, if any, that these land claims may have on our business.

DIVIDENDS

Suncor's 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. The company's Board approved an increase in the quarterly dividend to $0.11 per share from $0.10 per share in the second quarter of 2011. Dividends are paid subject to applicable law, if, as and when declared by the Board. 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	2011	2010	2009
Cash dividends per common share ($)	0.43	0.40	0.30

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, 2011, there were 1,558,636,368 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 company's Board 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.

Petro-Canada Public Participation Act

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 company's Board 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 or 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.

Credit 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 for growth projects 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, 2011. 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.

	Senior Unsecured	Outlook	Cdn$ Commercial Paper	US$ Commercial Paper
Standard & Poor's (S&P)	BBB+	Stable	A-1 (low)	A-2
Dominion Bond Rating Service (DBRS)	A (low)	Stable	R-1 (low)	Not rated
Moody's Investors Service (Moody's)	Baa2	Positive	Not rated	P-2

S&P credit ratings on long-term debt are on a rating scale that ranges from AAA to D, representing the range of such securities rated from highest to lowest quality. A rating of BBB by S&P is the fourth highest of 10 categories and indicates that the obligor had adequate capacity to meet its financial commitments. 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 the rating indicates the relative standing within a particular rating category. S&P credit ratings on commercial paper are on a short-term debt rating scale that ranges from A-1 (High) to C, representing the range of such securities rated from highest to lowest quality. A rating of A-1 (low) by S&P is the third highest of seven categories, with a (low) designation after the rating indicating a slightly higher susceptibility to the adverse effects of changes in circumstances and economic conditions, although 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 qualify for a rating of A-2 on the S&P global short-term rating scale. A rating of A-2 by S&P means the obligor is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than the A-1 rating, but the obligor's capacity to meet its financial commitment is satisfactory.

DBRS credit ratings on long-term debt are on a rating scale that ranges from AAA to D, representing the range of such securities rated from highest to lowest. A rating of A by DBRS is the third highest of 10 categories and is assigned to debt securities considered to be of good credit quality, with the capacity for the payment of financial obligations being substantial, but of a lesser credit quality than an AA rating. Entities in the A category may be vulnerable to future events, but qualifying negative factors are considered manageable. All rating categories other than AAA and D also contain designations for (high) and (low). The absence of either a (high) or (low) designation indicates the rating is in the middle of the category. The assignment of a (high) or (low) designation within a rating category indicates relative standing within that category. DBRS's credit ratings on commercial paper are on a short-term debt rating scale that ranges from R-1 (high) to D, representing the range of such securities rated from highest to lowest quality. 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 good credit quality. The capacity for the payment of short-term financial obligations as they become due is substantial, with overall strength not as favourable as higher rating categories. Entities in this category may be vulnerable to future events, but qualifying negative factors are considered manageable. Certain commercial paper categories are further denoted by (high), (medium) and (low) designations.

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 Baa 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. For certain ratings, 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. A rating of P-2 by Moody's for commercial paper is the second highest of four rating categories and indicates a strong ability to repay short-term obligations.

MARKET FOR SECURITIES

Our common shares are listed on the TSX in Canada, and on the NYSE in the U.S. The price ranges and the volumes traded on the TSX and NYSE for the year ended December 31, 2011, are as follows:

TSX

	Price Range (Cdn$)		
	High	Low	Trading Volume (000's)
2011			
January	41.73	36.31	86 963
February	47.27	39.64	113 291
March	47.09	39.91	114 219
April	44.78	40.61	78 958
May	44.56	37.94	97 689
June	40.70	36.31	88 738
July	39.60	36.35	64 996
August	36.81	28.71	152 854
September	31.56	25.61	130 795
October	33.10	23.97	124 137
November	33.75	28.07	110 485
December	31.87	27.30	98 747

NYSE

	Price Range (US$)		
	High	Low	Trading Volume (000's)
2011			
January	41.67	36.54	137 363
February	47.62	40.01	182 199
March	48.53	40.25	179 965
April	46.84	41.93	111 993
May	47.00	38.76	158 992
June	41.95	36.93	131 743
July	41.88	37.96	111 901
August	39.69	29.00	220 108
September	32.39	24.94	167 997
October	33.40	22.55	176 408
November	33.27	27.06	149 786
December	31.45	26.30	120 119

For information in respect of options to purchase common shares of Suncor and common shares issued upon the exercise of options and pursuant to our dividend reinvestment plan in 2011, see the Share Capital note to the 2011 audited 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. Richard L. George and Brian MacNeill are not standing for re-election at Suncor's 2012 annual general meeting, scheduled to be held on May 1, 2012.

Suncor Directors 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 Tenex Energy Inc. and a director of Winalta Inc. and Fort McKay Group of Companies, a community trust. He is also a director of Hull Child and Family Services, a non-profit organization.
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 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. and Strategy Summit Ltd. and until March 1, 2012 was a director of the Royal Bank of Canada. In addition, he is a member of the Order of Canada, a board member of the Alberta Bone and Joint Institute, an advisory member of the Canadian Institute for Advanced Research, Honorary 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 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 CEO of Suncor Energy Inc. He currently serves as a director of Canadian Pacific Railway and he chaired the 2008 Governor General's Canadian Leadership Conference. Mr. George was named a member of the Order of Canada in 2007.
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 is a strategic advisor to the law firm Heenan Blaikie LLP. He was the president and chief executive officer of SNC-Lavalin from 1996 to 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 director of the Royal Bank of Canada, PPP Canada Inc. and the Canadian Institute for Advanced Research, and as a member of the Engineering Institute of Canada, Engineers Canada and the Ordre des ingénieurs du Québec. Mr. Lamarre holds a Bachelor of Arts and a Bachelor of Arts and Science in Civil Engineering from Université Laval 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 Université Laval.
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 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 past 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, Nature Conservancy of Canada, Alberta chapter, and Royal Alexandra 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.
Eira M. Thomas [3][4] British Columbia, Canada	Director since 2006 Independent	Eira Thomas is a Canadian geologist with over twenty years of experience in the Canadian diamond business, including her previous roles as vice president of Aber Resources, now Harry Winston Diamond Corp., and as founder and CEO of Stornoway Diamond Corp. Currently, Ms. Thomas is a director of Lucara Diamond Corp. and Strongbow Exploration Inc. She also serves on the board of the Prospectors and Developers Association of Canada.

Steven W. Williams Alberta, Canada	Director since December 2011 Non-independent, management	Steve Williams has served as the chief operating officer of Suncor Energy Inc. since 2007. He was appointed as President of Suncor Energy Inc. in December of 2011. Mr. Williams is a fellow of the Institute of Chemical Engineers and is a member of the Institute of Directors. He is also co-chair of the Oil Sands Leadership Initiative (OSLI), a member of the CEO Committee of Syncrude Canada Limited, and a member of the Business Advisory Council, School of Business at the University of Alberta. In October of 2010, he was appointed to the Alberta Government Oil and Gas Economics Advisory Council.

(1) Human Resources and Compensation Committee

(2) Environment, Health, Safety and Sustainable Development Committee

(3) Audit Committee

(4) Governance Committee

Executive Officers

The following individuals are the executive officers of Suncor:

Name	Jurisdiction of Residence	Office
Richard L. George	Alberta, Canada	Chief Executive Officer
Steven W. Williams	Alberta, Canada	President and Chief Operating Officer
Bart W. Demosky	Alberta, Canada	Chief Financial Officer
Eric Axford	Alberta, Canada	Executive Vice President, Business Services
Boris Jackman	Ontario, Canada	Executive Vice President, Refining and Marketing
Mark Little	Alberta, Canada	Executive Vice President, Oil Sands and In Situ
Mike MacSween	Alberta, Canada	Executive Vice President, Major Projects
Steve Reynish	Alberta, Canada	Executive Vice President, Oil Sands Ventures
Paul Gardner	Alberta, Canada	Senior Vice President, Human Resources
Francois Langlois	Alberta, Canada	Senior Vice President, Exploration and Production
Janice Odegaard	Alberta, Canada	Senior Vice President, General Counsel and Corporate Secretary
Kris Smith	Alberta, Canada	Senior Vice President, Supply, Trading and Corporate Development

As at December 31, 2011, 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, no director or executive officer of Suncor is or has been within the last ten years a director, chief executive officer or chief financial officer of a company that: (a) was the subject of a cease trade or similar order, or an order that denied the relevant issuer access to any exemption under Canadian securities legislation that was in effect for a period of more than 30 consecutive days while the director or officer was acting in that capacity, other than Mr. MacNeill, who is presently a director of Oilsands Quest Inc. (Oilsands Quest), a company that has been subject to a cease trade order of the NYSE Amex since November 2011 for failure to meet certain NYSE Amex continued listing standards; or (b) was subject to a cease trade order or similar 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, that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in that capacity.

To the best of our knowledge, having made due inquiry, we confirm that, as at the date hereof, no director or executive officer of Suncor, or any of their respective personal holding companies, nor any shareholders holding a sufficient number of securities to affect materially the control of Suncor: (a) is, or has been within the last ten years, a director or executive officer of any company (including Suncor) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than: (i) Mr. Ford, a director of Suncor who is currently a director of USG Corporation, which 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; and (ii) Mr. MacNeill, a director of Suncor who is currently a director of Oilsands Quest, which is currently operating under the protection of the *Canada Companies' Creditors Arrangement Act*; or (b) has, within the last ten years, 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, executive officer or shareholder.

No director or executive officer of Suncor has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) 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.

AUDIT COMMITTEE INFORMATION

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

Composition of the Audit Committee

The Audit Committee is comprised of Mr. O'Brien (Chairman), Mr. D'Alessandro, Mr. MacNeill, Mr. Haseldonckx and Ms. Thomas. All members are independent and financially literate. The education and expertise of each member is described in the Directors and Executive Officers section of this AIF.

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 Mr. O'Brien and Mr. 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 practiced 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 company's financial statements and other financial information and to make knowledgeable and thorough inquiries whether the financial statements fairly present the financial condition, results of operations and cash flows of the company in accordance with generally accepted accounting principles, or whether the financial statements and other financial information, taken together, fairly present the financial condition, results of operations and cash flows of the company.

Audit Committee Financial Expert

An "Audit Committee Financial Expert" means a person who, in the judgment of the company's Board of Directors, has the following attributes:

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

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

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

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

(e) an understanding of audit committee functions.

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

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

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

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

(d) other relevant experience.

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 2011 and 2010, the nature of which are described below, were as follows:

($ thousands)	2011	2010
Audit Fees	6 145	4 873
Audit-Related Fees	423	637
Tax Fees	50	—
All Other Fees	9	4
Total	6 627	5 514

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 were paid for professional services rendered by the auditors for the review of quarterly financial statements and for the preparation of reports on specified procedures as they relate to joint venture audits and attest services not required by statute or regulation. Tax Fees for corporate tax filings and tax planning were paid in a foreign jurisdiction where Suncor has limited activity. All Other Fees

were subscriptions to auditor-provided and supported tools. The services described for Audit Fees, Audit-Related Fees and Tax 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. See Schedule "B" in this AIF for the company's Policy and Procedures for Pre-Approval of Audit and Non-Audit Services.

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 or executive officer, or any associate or affiliate of these persons has, or has had, any material interests, direct or indirect, 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, Alberta, Montreal, Quebec, Toronto, Ontario and Vancouver, British Columbia and Computershare Trust Company Inc. in Denver, Colorado.

MATERIAL CONTRACTS

During the year ended December 31, 2011, 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 *Continuous Disclosure Obligations*.

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 qualified reserves evaluators. The 2011 audited 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 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 four of the NYSE rules: (i) have an audit committee that satisfies the requirements of the United States *Securities Exchange Act of 1934*, as amended; (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; (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; and (iv) provide annual and, as required, written affirmations of compliance with applicable NYSE Corporate Governance rules. The company has disclosed in its 2012 management proxy circular, which is available on our 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 2011 audited Consolidated Financial Statements for our most recently completed financial year and in 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.

ADVISORY – FORWARD-LOOKING INFORMATION

This AIF contains certain forward-looking statements and other information based on information available at the time the statement was made and in light of Suncor's experience and perception of historical trends, including expectations and assumptions concerning the accuracy of reserves and resources 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. In addition, all other statements that address expectations or projections about the future, and other statements and information about Suncor's strategy for growth, expected and future expenditures or investment decisions, commodity prices, costs, schedules, production volumes, operating and financial results, future financing and capital activities, and expected impact of future commitments are forward-looking statements. Some of the forward-looking statements and information may be identified by words like "expects", "anticipates", "estimates", "plans", "scheduled", "intends", "believes", "projects", "indicates", "could", "focus", "vision", "goal", "outlook", "proposed", "target", "objective", "continue" and similar expressions.

Forward-looking statements in this AIF include references to:

Suncor's expectations about production volumes and the performance of its existing assets, including:

- *The TRO$_{TM}$ process is expected to significantly reduce the area required for tailings management, increase the speed at which Suncor is able to reclaim its tailings ponds, enable Suncor to meet the requirements of the Tailings Directive issued by the ERCB in 2009, eliminate the need for new tailings ponds at existing mining operations, improve tailings management going forward and, in the years ahead, reduce the number of tailings ponds presently in operation;*
- *Gross design capacities for Suncor's operated and non-operated facilities;*
- *Suncor's plans to develop its proved undeveloped reserves and its probable undeveloped reserves;*
- *Production estimates for 2012; and*
- *The company's expectation that, as production from the Firebag Stage 3 expansion increases, the Firebag SOR will decrease.*

The anticipated duration and impact of planned maintenance events, including:

- *Remaining H_2S remediation for Terra Nova that is anticipated to be completed concurrent with the dockside maintenance program, which includes the replacement of the FPSO swivel, scheduled to commence in the third quarter of 2012; and*
- *The 18-week off-station maintenance program for the White Rose FPSO scheduled to commence in the second quarter of 2012, primarily to address issues with the FPSO propulsion system.*

Suncor's expectations about where future capital expenditures will be directed, the timing for completion of growth and other significant projects, and the results of such projects, including:

- *Suncor's ten-year growth strategy to increase production to over one million boe/d by 2020, which is expected to include arrangements with respective joint venture owners for the development of the Fort Hills and Joslyn oil sands mining projects and the restart of construction of the Voyageur upgrader, the continued development of the company's Firebag and MacKay River in situ operations, and investments in and ongoing production from international and offshore operations;*
- *The company's expectations that the Voyageur South and Audet leases can be developed using mining techniques, and that the Meadow Creek, Lewis, Chard and Kirby leases can be developed using in situ techniques;*
- *Suncor's plans for the Firebag Stage 4 expansion, scheduled to be completed in 2013, which include two well pads, a central processing facility and two cogeneration units;*
- *The design capacities for the Firebag Stage 3 and Stage 4 expansions are 62,500 bbls/d of bitumen each;*
- *Suncor's expectation that the commissioning of the cogeneration units for Firebag Stage 3 will be completed in the first quarter of 2012;*
- *Suncor's integrated plans for the entire Firebag operation, such that steam and electricity generated by any of the central processing facilities and cogeneration units can be used to power operations at any of the well pads, and that bitumen extracted from any well pad can be processed at any of the central processing facilities;*
- *Plans for centrifuge technology at Syncrude that separates water from tailings;*
- *Preliminary designs for Fort Hills plan for 164,000 bbls/d of bitumen production (gross) and for Joslyn North plan for 100,000 bbls/d of bitumen production (gross);*
- *The company's expectations that bitumen production from the Fort Hills and Joslyn mines will be upgraded into SCO and other products by the Voyageur upgrader, and preliminary design plans for 200,000 bbls/d (gross) of upgrading capacity for the Voyageur upgrader;*
- *Development plans for the HSEU, which include drilling up to two additional producing wells and five water injection wells in a subsea glory hole;*
- *A water injection well to support initial production from the West White Rose Extension that is expected be completed in the second quarter of 2012;*
- *The plans of the joint venture owners of Hebron to make a decision to sanction the project in late 2012, and the company's expectations that initial production will occur in late 2017;*
- *Plans for Hebron that include a concrete GBS, integrated topsides deck, 1.2 mmbbls of oil storage capacity, and 52 well slots, with a gross oil production capacity of 150,000 bbls/d;*
- *Development plans for Golden Eagle, which include an initial gross production rate of 70,000 boe/d from 20 development wells, development cost of £2 billion (Cdn$3.3 billion) and the company's expectations that first production will occur late in 2014 or early 2015;*
- *Plans for the drilling of the third appraisal well for the Beta discovery, which is scheduled to commence in the second quarter of 2012;*
- *Plans to drill an exploration well in the Romeo prospect; and*
- *Suncor's future development costs and expected development activities identified in the Statement of Reserves Data and Other Oil and Gas Information section of this AIF.*

Also:

- *Anticipated abandonment and reclamation costs;*
- *Anticipated royalty and tax rates and the impact of these rates on Suncor;*
- *Suncor's expectations that the cost of meeting new environmental and climate change regulations will not be so high as to cause material disadvantage to the company or material damage to its competitive positioning, and that GHG regulation will evolve with a moderate carbon price signal, and that the price regime will progress cautiously;*
- *Suncor's expectations that it will continue to engage the appropriate governmental bodies in meaningful dialogue in an effort to develop a harmonized system for GHG emissions regulations that focuses on achieving actual reduction goals and sustainable resource development;*
- *Suncor's belief that it will have sufficient funds available to fund its planned expenditures for 2012;*
- *Suncor's belief that existing cash balances, internally generated cash flows and existing credit facilities are sufficient to fund future development activities;*
- *Suncor's estimates for its compliance costs for GHG regulations in Alberta will be between $10 million and $15 million; and*
- *Limitations on the interim BVM, as recently enacted.*

Forward-looking statements and information 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. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements, so readers are cautioned not to place undue reliance on them.

The financial and operating performance of the company's reportable operating segments, specifically Oil Sands, Exploration and Production, and Refining and Marketing, may be affected by a number of factors:

Factors that affect our Oil Sands segment include, but are not limited to, volatility in the prices for crude oil and other production, and the related impacts of fluctuating light/heavy and sweet/sour crude oil differentials; changes in the demand for refinery feedstock and diesel fuel, including the possibility that refiners that process our proprietary production will be closed, experience equipment failure or other accidents; our ability to operate facilities reliably in order to meet production targets; the output of newly commissioned facilities, the performance of which may be difficult to predict during initial operations; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; our dependence on pipeline capacity and other logistical constraints, which may affect our ability to distribute our products to market; our ability to finance growth and sustaining capital expenditures; the availability of bitumen feedstock for upgrading operations, which can be negatively affected by poor ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage, in situ reservoir and equipment performance, or the unavailability of third-party bitumen; inflationary pressures on operating costs, including labour, natural gas and other energy sources in oil sands processes; our ability to complete projects, including planned maintenance events, both on time and on budget, which could be impacted by competition from other projects (including other oil sands projects) for goods and services and demands on infrastructure in Fort McMurray and the surrounding area (including housing, roads and schools); risks and uncertainties associated with obtaining regulatory and stakeholder approval for exploration and development activities; changes to royalty and tax legislation and related agreements that could impact our business, such as our current dispute with the Alberta Department of Energy in respect of the Bitumen Valuation Methodology Regulation; the potential for disruptions to operations and construction projects as a result of our relationships with labour unions that represent employees at our facilities; and changes to environmental regulations or legislation.

Factors that affect our Exploration and Production segment include, but are not limited to, volatility in crude oil and natural gas prices; operational risks and uncertainties associated with oil and gas activities, including unexpected formations or pressures, premature declines of reservoirs, fires, blow-outs, equipment failures and other accidents, uncontrollable flows of crude oil, natural gas or well fluids, and pollution and other environmental risks; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; adverse weather conditions, which could disrupt output from producing assets or impact drilling programs, resulting in increased costs and/or delays in bringing on new production; political, economic and socio-economic risks associated with Suncor's foreign operations, including the unpredictability of operating in Libya and the possibility that operations in Syria may be constrained by civil and political unrest; risks and uncertainties associated with obtaining regulatory and stakeholder approval for exploration and development activities; the potential for disruptions to operations and construction projects as a result of our relationships with labour unions that represent employees at our facilities; and market demand for mineral rights and producing properties, potentially leading to losses on disposition or increased property acquisition costs.

Factors that affect our Refining and Marketing segment include, but are not limited to, fluctuations in demand and supply for refined products that impact the company's margins; market competition, including potential new market entrants; our ability to reliably operate refining and marketing facilities in order to meet production or sales targets; the possibility that completed

maintenance activities may not improve operational performance or the output of related facilities; risks and uncertainties affecting construction or planned maintenance schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period; and the potential for disruptions to operations and construction projects as a result of our relationships with labour unions or employee associations that represent employees at our refineries and distribution facilities.

Additional risks, uncertainties and other factors that could influence financial and operating performance of all of Suncor's operating segments and activities include, but are not limited to, changes in general economic, market and business conditions, such as commodity prices, interest rates and currency exchange rates; fluctuations in supply and demand for Suncor's products; the successful and timely implementation of capital projects, including growth projects and regulatory projects; 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; actions by government authorities, including the imposition of taxes or changes to fees and royalties, and changes in environmental and other regulations; the ability and willingness of parties with whom we have material relationships to perform their obligations to us; the occurrence of unexpected events such as fires, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; the potential for security breaches of Suncor's information systems by computer hackers or cyberterrorists, and the unavailability or failure of such systems to perform as anticipated as a result of such breaches; our ability to find new oil and gas reserves that can be developed economically; the accuracy of Suncor's reserves, resources and future production estimates; market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; maintaining an optimal debt to cash flow ratio; the success of the company's risk management activities using derivatives and other financial instruments; the cost of compliance with current and future environmental laws; risks and uncertainties associated with closing a transaction for the purchase or sale of an oil and gas property, including estimates of the final consideration to be paid or received, 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 that are customary to transactions of this nature; 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 that is needed to reduce the margin of error and increase the level of accuracy; failure to realize anticipated synergies or cost-savings; risks regarding the integration of Suncor and Petro-Canada after the merger; and incorrect assessments of the values of assets acquired and liabilities assumed in the merger with Petro-Canada. The foregoing important factors are not exhaustive.

Many of these risk factors and other assumptions related to Suncor's forward-looking statements and information are discussed in further detail throughout this AIF and in our MD&A. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files 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.

SCHEDULE "A"

AUDIT COMMITTEE MANDATE

The Audit Committee

The bylaws 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 and 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 bylaws, 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 judgments 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 Consolidated 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; and

    (B) providing information to the qualified reserves evaluators (the 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, and 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 (the 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, information technology, 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 February 1, 2011.

SCHEDULE "B"

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 (SEC) and the Ontario Securities Commission respectively have 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 SEC 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, which are reasonably related to the performance of the audit or review of financial statements and not categorized under Audit Services 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; and

(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 that 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; and

  (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 must be 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, worldwide, 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:

(f) Provide regular, detailed fee reporting including balances in the work in progress account; and

(g) 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.

Approved and Accepted April 28, 2004.

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 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 systems 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. Any of the following:

- 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, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2011, 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 revenues (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, 2011, 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 Revenues (before income taxes, 10% discount rate-$MM)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	Oil Sands In-Situ January 12, 2012	Canada	—	17 247	—	17 247
GLJ Petroleum Consultants	Oil Sands Mining January 12, 2012	Canada	—	31 757	—	31 757
						49 004

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

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 1, 2012

"Caralyn P. Bennett"

Caralyn P. Bennett, P. Eng.
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 the Company's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2011, 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 revenues (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, 2011, 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
Sproule Associates Limited	East Coast Canada February 16, 2012	Newfoundland Offshore, Canada	—	7 904	—	7 904
Sproule Associates Limited	North America Onshore February 16, 2012	Western Canada	—	2 126	—	2 126
Sproule International Limited	North Sea February 16, 2012	North Sea, United Kingdom	—	9 026	—	9 026
Sproule International Limited	Other International February 16, 2012	Libya, Syria	—	6 195	—	6 195
			—	**25 251**	**—**	**25 251**

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 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 1, 2012

"Harry J. Helwerda"

Harry J. Helwerda, P. Eng., FEC
Executive Vice-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 revenues as at December 31, 2011, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The reports 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
Chief Executive Officer

"*Bart W. Demosky*"
BART W. DEMOSKY
Chief Financial Officer

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

"*Michael W. O'Brien*"
MICHAEL W. O'BRIEN
Chair of the Audit Committee

March 1, 2012



Box 2844, 150 - 6th Avenue S.W., Calgary,
Alberta, Canada T2P 3E3
tel: (403) 296-6000 fax: (403) 296-
3030 info@suncor.com www.suncor.com

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

Suncor Energy Inc. (the "Registrant") undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the staff of the Securities and Exchange Commission ("SEC"), and to furnish promptly, when requested to do so by the SEC staff, information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises, or transactions in said securities.

B. Consent to Service of Process

The Registrant has filed previously with the SEC a Form F-X in connection with the Common Shares.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

See pages 79 and 80 of Exhibit 99-1 and page 70 of Exhibit 99-2.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See pages 81 and 82 of Exhibit 99-1.

AUDIT COMMITTEE FINANCIAL EXPERT

See pages 74 and 75 of Annual Information Form.

CODE OF ETHICS

See pages 25 and 77 of Annual Information Form.

FEES PAID TO PRINCIPAL ACCOUNTANT

See pages 75 and 76 of Annual Information Form.

AUDIT COMMITTEE PRE-APPROVAL POLICIES

See Schedule "B" of Annual Information Form.

APPROVAL OF NON-AUDIT SERVICES

See Schedule "B" of Annual Information Form.

OFF-BALANCE SHEET ARRANGEMENTS

See page 55 of Exhibit 99-2.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page 55 of Exhibit 99-2.

IDENTIFICATION OF THE AUDIT COMMITTEE

See page 74 of Annual Information Form.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

SUNCOR ENERGY INC.

DATE: March 1, 2012

PER: /s/ BART W. DEMOSKY

Bart W. Demosky
Chief Financial Officer

EXHIBIT INDEX

Exhibit No.	Description
99-1	Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2011
99-2	Management's Discussion and Analysis for the fiscal year ended December 31, 2011, dated February 23, 2012
99-3	Consent of PricewaterhouseCoopers LLP
99-4	Consent of GLJ Petroleum Consultants Ltd.
99-5	Consent of Sproule Associates Limited and Sproule International Limited
99-6	Certificate of Chief Executive Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-7	Certificate of the Chief Financial Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-8	Certificate of the Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99-9	Certificate of the Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

QuickLinks

ANNUAL INFORMATION FORM
UNDERTAKING AND CONSENT TO SERVICE OF PROCESS
DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING
ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM
AUDIT COMMITTEE FINANCIAL EXPERT
CODE OF ETHICS
FEES PAID TO PRINCIPAL ACCOUNTANT
AUDIT COMMITTEE PRE-APPROVAL POLICIES
APPROVAL OF NON-AUDIT SERVICES
OFF-BALANCE SHEET ARRANGEMENTS
TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS
IDENTIFICATION OF THE AUDIT COMMITTEE
SIGNATURES
EXHIBIT INDEX

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EXHIBIT 99-1

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2011

MANAGEMENT'S STATEMENT
OF RESPONSIBILITY FOR FINANCIAL REPORTING

The management of Suncor Energy Inc. is responsible for the presentation and preparation of the accompanying consolidated financial statements of Suncor Energy Inc. and all related financial information contained in the Annual Report, including Management's Discussion and Analysis.

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. They include certain amounts that are based on estimates and judgments.

In management's opinion, the consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies adopted by management. If alternate accounting methods exist, management has chosen those policies it deems the most appropriate in the circumstances. In discharging its responsibilities for the integrity and reliability of the financial statements, management maintains and relies upon a system of internal controls designed to ensure that transactions are properly authorized and recorded, assets are safeguarded against unauthorized use or disposition and liabilities are recognized. These controls include quality standards in hiring and training of employees, formalized policies and procedures, a corporate code of conduct and associated compliance program designed to establish and monitor conflicts of interest, the integrity of accounting records and financial information among others, and employee and management accountability for performance within appropriate and well-defined areas of responsibility.

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

The Audit Committee of the Board of Directors, composed of five independent directors, reviews the effectiveness of the company's financial reporting systems, management information systems, internal control systems and internal auditors. It recommends to the Board of Directors the external auditor to be appointed by the shareholders at each annual meeting and reviews the independence and effectiveness of their work. In addition, it reviews with management and the external auditor any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of management that may be material for financial reporting purposes. The Audit Committee appoints the independent reserve evaluators. The Audit Committee meets at least quarterly to review and approve interim financial statements prior to their release, as well as annually to review Suncor's annual financial statements and Management's Discussion and Analysis, Annual Information Form/Form 40-F, and annual reserves and resources estimates, and recommend their approval to the Board of Directors. The internal auditors and the external auditor, PricewaterhouseCoopers LLP, have unrestricted access to the company, the Audit Committee and the Board of Directors.



Richard L. George
Chief Executive Officer



Bart W. Demosky
Chief Financial Officer

February 23, 2012

The following report is provided by management in respect of the company's internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the U.S. Securities Exchange Act of 1934):

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

1. Management is responsible for establishing and maintaining adequate internal control over the company's financial reporting.

2. Management has used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework in Internal Control – Integrated Framework to evaluate the effectiveness of the company's internal control over financial reporting.

3. Management has assessed the effectiveness of the company's internal control over financial reporting as at December 31, 2011, and has concluded that such internal control over financial reporting was effective as of that date. Additionally, based on this assessment, management determined that there were no material weaknesses in internal control over financial reporting as at December 31, 2011. Because of inherent limitations, systems of internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

4. The effectiveness of the company's internal control over financial reporting as at December 31, 2011 has been audited by PricewaterhouseCoopers LLP, independent auditor, as stated in their report which appears herein.



Richard L. George
Chief Executive Officer



Bart W. Demosky
Chief Financial Officer

February 23, 2012

INDEPENDENT AUDITOR'S REPORT

TO THE SHAREHOLDERS OF SUNCOR ENERGY INC.

We have completed an integrated audit of Suncor Energy Inc.'s December 31, 2011 consolidated financial statements and its internal control over financial reporting as at December 31, 2011 and an audit of its December 31, 2010 consolidated financial statements. Our opinions, based on our audits, are presented below.

REPORT ON THE CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated financial statements of Suncor Energy Inc. ("the company"), which comprise the consolidated balance sheets as at December 31, 2011, December 31, 2010 and January 1, 2010 and the consolidated statements of comprehensive income, changes in shareholders' equity and cash flows for the years ended December 31, 2011 and December 31, 2010, and the related notes, which comprise a summary of significant accounting policies.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2011, December 31, 2010 and January 1, 2010 and its financial performance and its cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited the company's internal control over financial reporting as at December 31, 2011, based on criteria established in Internal Control – Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Management's responsibility for internal control over financial reporting

Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting.

Auditor's responsibility

Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on the company's internal control over financial reporting.

Definition of internal control over financial reporting

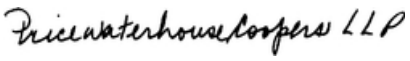
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Inherent limitations

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Opinion

In our opinion, the company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2011, based on criteria established in Internal Control – Integrated Framework issued by COSO.



PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

February 23, 2012

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 ($ millions)	**2011**	2010
Revenues and Other Income		
Operating revenues, net of royalties (note 7)	**39 337**	32 003
Other income (note 8)	**453**	601
	39 790	32 604
Expenses		
Purchases of crude oil and products	**18 723**	14 831
Operating, selling and general (notes 9 and 27)	**8 424**	7 984
Transportation	**736**	703
Depreciation, depletion, amortization and impairment (note 10)	**3 952**	3 803
Exploration	**116**	218
Loss (gain) on disposal of assets	**136**	(975)
Project start-up costs	**163**	77
Financing expenses (note 11)	**471**	187
	32 721	26 828
Earnings before Income Taxes	**7 069**	5 776
Income Taxes (note 12)		
Current	**1 121**	1 196
Deferred	**1 644**	751
	2 765	1 947
Net Earnings	**4 304**	3 829
Other Comprehensive Income (Loss)		
Foreign currency translation adjustment	**230**	(437)
Foreign currency translation adjustment relating to assets held for sale	**—**	(63)
Foreign currency translation reclassified to net earnings	**14**	49
Cash flow hedges reclassified to net earnings	**—**	(1)
Actuarial loss on employee retirement benefit plans, net of income taxes of $117 (2010 – $49)	**(339)**	(152)
Other Comprehensive Income (Loss)	**(95)**	(604)
Total Comprehensive Income	**4 209**	3 225
Per Common Share (dollars) (note 13)		
Net earnings – basic	**2.74**	2.45
Net earnings – diluted	**2.67**	2.43
Cash dividends	**0.43**	0.40

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Assets			
Current assets			
Cash and cash equivalents (note 14)	**3 803**	1 077	505
Accounts receivable	**5 412**	5 253	3 936
Inventories (note 16)	**4 205**	3 141	2 971
Income taxes receivable	**704**	734	587
Assets held for sale (note 17)	**—**	762	—
Total current assets	**14 124**	10 967	7 999
Property, plant and equipment, net (note 18)	**52 589**	49 958	51 556
Exploration and evaluation (note 19)	**4 554**	3 961	4 342
Other assets (note 20)	**311**	230	259
Goodwill and other intangible assets (note 21)	**3 139**	3 422	3 433
Deferred income taxes (note 12)	**60**	69	210
Total assets	**74 777**	68 607	67 799
Liabilities and Shareholders' Equity			
Current liabilities			
Short-term debt (note 22)	**763**	1 984	2 317
Current portion of long-term debt (note 22)	**12**	518	25
Accounts payable and accrued liabilities	**7 755**	6 443	5 773
Current portion of provisions (note 25)	**811**	608	882
Income taxes payable	**969**	929	1 274
Liabilities associated with assets held for sale (note 17)	**—**	586	—
Total current liabilities	**10 310**	11 068	10 271
Long-term debt (note 22)	**10 004**	9 829	11 679
Other long-term liabilities (note 23)	**2 392**	2 103	2 073
Provisions (note 25)	**3 752**	2 504	3 305
Deferred income taxes (note 12)	**9 719**	7 911	7 986
Shareholders' equity	**38 600**	35 192	32 485
Total liabilities and shareholders' equity	**74 777**	68 607	67 799

The accompanying notes are an integral part of the consolidated financial statements.

Approved on behalf of the Board of Directors:

Steven W. Williams
Director

Michael W. O'Brien
Director

February 23, 2012

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ millions)	**2011**	2010
Operating Activities		
Net earnings	**4 304**	3 829
Adjustments for:		
Depreciation, depletion, amortization and impairment	**3 952**	3 803
Deferred income taxes	**1 644**	751
Accretion	**157**	235
Unrealized foreign exchange loss (gain) on U.S. dollar denominated long-term debt	**183**	(426)
Change in fair value of derivative contracts	**(40)**	(285)
Loss (gain) on disposal of assets	**136**	(975)
Share-based compensation	**(102)**	113
Exploration	**28**	96
Other	**(516)**	(485)
Decrease (increase) in non-cash working capital (note 15)	**242**	(1 170)
Cash flow provided by operating activities	**9 988**	5 486
Investing Activities		
Capital and exploration expenditures	**(6 850)**	(6 010)
Acquisitions	**(842)**	—
Proceeds from disposal of assets	**3 074**	3 088
Other investments	**(6)**	3
Decrease (increase) in non-cash working capital (note 15)	**26**	(193)
Cash flow used in investing activities	**(4 598)**	(3 112)
Financing Activities		
Net change in short-term debt	**(1 221)**	(333)
Net change in long-term debt	**(4)**	(924)
Repayment of long-term debt	**(500)**	—
Issuance of common shares under share option plans	**213**	81
Purchase of common shares for cancellation (note 26)	**(500)**	—
Dividends paid on common shares	**(664)**	(611)
Cash flow used in financing activities	**(2 676)**	(1 787)
Increase in Cash and Cash Equivalents	**2 714**	587
Effect of foreign exchange on cash and cash equivalents	**12**	(15)
Cash and cash equivalents at beginning of period	**1 077**	505
Cash and Cash Equivalents at End of Period	**3 803**	1 077
Supplementary Cash Flow Information		
Interest paid	**672**	690
Income taxes paid	**885**	1 193

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

($ millions)	Share Capital	Contributed Surplus	Foreign Currency Translation	Cash Flow Hedge	Retained Earnings	Total	Number of Common Shares (thousands)
At January 1, 2010	20 053	536	—	15	11 881	32 485	1 559 778
Net earnings	—	—	—	—	3 829	3 829	—
Foreign currency translation adjustment	—	—	(451)	—	—	(451)	—
Net change in cash flow hedges	—	—	—	(1)	—	(1)	—
Actuarial loss on employee retirement benefit plans	—	—	—	—	(152)	(152)	—
Total comprehensive income (loss)	—	—	(451)	(1)	3 677	3 225	—
Dividends paid on common shares	—	—	—	—	(611)	(611)	—
Issued under share option plans	122	(33)	—	—	—	89	5 292
Issued under dividend reinvestment plan	13	—	—	—	(13)	—	419
Share-based compensation expense	—	4	—	—	—	4	—
At December 31, 2010	20 188	507	(451)	14	14 934	35 192	1 565 489
Net earnings	**—**	**—**	**—**	**—**	**4 304**	**4 304**	**—**
Foreign currency translation adjustment	**—**	**—**	**244**	**—**	**—**	**244**	**—**
Actuarial loss on employee retirement benefit plans	**—**	**—**	**—**	**—**	**(339)**	**(339)**	**—**
Total comprehensive income	**—**	**—**	**244**	**—**	**3 965**	**4 209**	**—**
Dividends paid on common shares	**—**	**—**	**—**	**—**	**(664)**	**(664)**	**—**
Issued under share option plans	**325**	**(57)**	**—**	**—**	**—**	**268**	**9 920**
Issued under dividend reinvestment plan	**12**	**—**	**—**	**—**	**(12)**	**—**	**355**
Purchase of common shares for cancellation (note 26)	**(222)**	**—**	**—**	**—**	**(278)**	**(500)**	**(17 128)**
Share-based compensation expense	**—**	**94**	**—**	**—**	**—**	**94**	**—**
Income tax benefit of stock option deduction in the U.S.	**—**	**1**	**—**	**—**	**—**	**1**	**—**
At December 31, 2011	**20 303**	**545**	**(207)**	**14**	**17 945**	**38 600**	**1 558 636**

The accompanying notes are an integral part of the consolidated financial statements.

1. REPORTING ENTITY AND DESCRIPTION OF THE BUSINESS

Suncor Energy Inc. (Suncor or the company) is an integrated energy company headquartered in Canada. Suncor's operations include oil sands development and upgrading, onshore and offshore oil and gas production, petroleum refining, and product marketing primarily under the Petro-Canada brand. The consolidated financial statements of the company comprise the company and its subsidiaries and the company's interests in associates and jointly controlled entities.

The address of the company's registered office is 150 - 6th Avenue S.W., Calgary, Alberta, Canada, T2P 3E3.

2. BASIS OF PREPARATION

(a) Statement of Compliance

These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) as issued by the Canadian Institute of Chartered Accountants. In 2010, Canadian GAAP was revised to incorporate International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board. Effective January 1, 2011, the company's consolidated financial statements have been prepared in accordance with IFRS, and IFRS 1 *First-Time Adoption of International Financial Reporting Standards* (IFRS 1) has been applied. In previous years, the company prepared its consolidated financial statements in accordance with Canadian generally accepted accounting principles in effect prior to January 1, 2011 (Previous GAAP). Comparative information has been restated from Previous GAAP to IFRS (see note 6).

The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as at February 23, 2012, the date the Board of Directors approved the statements.

(b) Basis of Measurement

The consolidated financial statements are prepared on a historical cost basis except as detailed in the accounting policies disclosed in note 3. The accounting policies described in note 3 have been applied consistently to all periods presented in these financial statements except for the opening IFRS consolidated balance sheet, which has utilized certain exemptions available under IFRS 1 (see note 6).

(c) Functional Currency and Presentation Currency

These consolidated financial statements are presented in Canadian dollars, which is the company's functional currency.

(d) Use of Estimates and Judgment

The timely preparation of financial statements requires that management make estimates and assumptions and use judgment. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Significant estimates and judgment used in the preparation of the financial statements are described in note 4.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Principles of Consolidation

The company consolidates its interest in entities it controls. Control comprises the power to govern an entity's financial and operating policies to obtain benefits from its activities. Suncor recognizes its share of assets, liabilities, income and expenses, on a line-by-line basis, of its jointly controlled entities and jointly controlled assets. Investments in entities over which the company has significant influence are accounted for using the equity method. All intercompany balances and transactions have been eliminated.

(b) Foreign Currency Translation

Functional currencies of the company's individual entities represent the currency of the primary economic environment in which the entity operates. Transactions in foreign currencies are translated to the appropriate functional currency at foreign exchange rates that approximate those on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the appropriate functional currency at foreign exchange rates at the balance sheet date. Foreign exchange

differences arising on translation are recognized in earnings. Non-monetary assets that are measured in a foreign currency at historical cost are translated using the exchange rate at the date of the transaction.

In preparing the company's consolidated financial statements, the financial statements of each entity are translated into Canadian dollars. The assets and liabilities of foreign operations are translated into Canadian dollars at exchange rates at the balance sheet date. Revenues and expenses of foreign operations are translated into Canadian dollars using foreign exchange rates that approximate those on the date of the underlying transaction. Foreign exchange differences are recognized in other comprehensive income.

If the company or any of its investments dispose of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the accumulated foreign currency translation gains or losses related to the foreign operation are recognized in net earnings.

(c) Revenues

Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products and refined petroleum products is recorded when title passes to the customer and collection is reasonably assured. Revenue from properties in which the company has an interest with other producers is recognized on the basis of the company's net working interest. Crude oil and natural gas sold below or above the company's working interest share of production results in production underlifts or overlifts. Underlifts are recorded as a receivable at market value with a corresponding increase to revenues, while overlifts are recorded as a payable at market value with a corresponding decrease to revenues. Revenue from oil and natural gas production is recorded net of royalty expense.

International operations conducted pursuant to exploration and production sharing agreements (EPSAs) are reflected in the consolidated financial statements based on the company's working interest. Under the EPSAs, the company and other non-governmental partners, if any, pay all exploration costs and a pro-rata share of costs to develop and operate the concessions. Each EPSA establishes specific terms for the company to recover these costs (Cost Recovery Oil) and to share in the production profits (Profit Oil). Cost Recovery Oil is determined in accordance with a formula that is generally limited to a specified percentage of production during each fiscal year. Profit Oil is that portion of production remaining after deducting Cost Recovery Oil and is shared between the joint venture partners and the respective government. Cost Recovery Oil and Profit Oil are reported as sales revenue. Income tax amounts that the company would pay under the laws of the respective countries are paid by the company's governmental joint venture partners on our behalf, and the company reports these amounts as sales revenues. All other government stakes are considered to be royalty interests.

Physical and financial contracts entered into for trading purposes are considered derivative financial instruments, and any changes in fair value are recorded on a net basis in Other Income.

(d) Cash and Cash Equivalents

Cash and cash equivalents consist primarily of cash in banks, term deposits, certificates of deposit and all other highly liquid investments at the time of purchase.

(e) Inventories

Inventories of crude oil and refined products, other than inventories held for trading purposes, are valued at the lower of cost, using the first-in, first-out method, and net realizable value. Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location. Materials and supplies are valued at the lower of average cost and net realizable value.

Inventories held for trading purposes in the company's energy supply and trading operations are carried at fair value less costs to sell, and any changes in fair value are recognized within Other Income.

(f) Exploration and Evaluation Assets

The costs to acquire non-producing oil and gas properties or licence to explore, exploratory well expenditures and the costs to evaluate the commercial potential of underlying resources, including related borrowing costs, are initially capitalized as Exploration and Evaluation assets. Certain exploration costs, including geological, geophysical, seismic, and sampling on oil sands properties, are charged to Exploration expense as incurred.

Exploration and evaluation assets are subject to technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. If an area or exploration well is no longer considered commercially viable, the related capitalized costs are charged to net earnings.

When management determines with reasonable certainty that an exploration and evaluation asset will be developed, as evidenced by the classification of proved or probable reserves and the appropriate internal and external approvals, the asset is transferred to Property, Plant and Equipment.

(g) Property, Plant and Equipment

Property, plant and equipment are recorded at cost.

The costs to acquire developed or producing oil and gas properties and to develop oil and gas properties, including completing geological and geophysical surveys and drilling development wells, and the costs to construct and install dedicated infrastructure, such as wellhead equipment and supporting assets, mine development, offshore platforms and subsea structures, are capitalized as oil and gas properties within Property, Plant and Equipment.

The costs to construct, install and commission, or acquire, oil and gas production equipment, including oil sands upgraders, extraction plants, mine equipment, in situ processing facilities, power generation, utility plants, and natural gas processing plants, and all renewable energy, refining, distribution, marketing assets and related decommissioning and restoration obligations, are capitalized as Property, Plant and Equipment. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the item will flow to the company, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized.

Stripping activity required to access oil sands mining resources incurred in the initial development phase is capitalized as part of the investment in the construction cost of the mine. Stripping costs incurred in the production phase are charged to expense as they normally relate to production for the period.

The costs of planned major inspection, overhaul and turnaround activities that maintain property, plant and equipment and benefit future years of operations are capitalized. Recurring planned maintenance activities performed on shorter intervals are expensed as operating costs. Replacements outside of a major inspection, overhaul or turnaround are capitalized when it is probable that future economic benefits will flow to the company and the associated carrying amount of the replaced asset is derecognized.

Leases that transfer substantially all the benefits and risks of ownership to the company are recorded as finance lease assets within Property, Plant and Equipment. Costs for all other leases are recorded as operating expense as incurred.

Borrowing costs relating to assets that take a substantial period of time to construct for their intended use are capitalized as part of Property, Plant and Equipment. Capitalization of borrowing costs ceases when the asset is in the location and condition necessary for it to be capable of operating as intended. Capitalization of borrowing costs is suspended when construction of an asset is ceased for extended periods.

(h) Depreciation, Depletion and Amortization

Exploration and evaluation assets are not subject to depreciation, depletion and amortization, with the exception of natural gas leases. Once transferred to Property, Plant and Equipment and commercial production commences, these costs are depleted on a unit-of-production basis over proved developed reserves with the exception of property acquisition costs which are depleted over proved reserves.

Capital expenditures associated with significant development projects are not depleted until assets are substantially complete and ready for their intended use.

Costs to develop oil and gas properties, and costs of dedicated infrastructure, such as wellhead equipment, offshore platforms and subsea structures, are depleted on a unit-of-production basis over proved developed reserves. A portion of these costs may not be depleted if they relate to undeveloped reserves.

Major components of Property, Plant and Equipment are depreciated on a straight-line basis over their expected useful lives.

Natural gas processing plants and transportation assets	15 to 25 years
Oil sands upgraders, extraction plants and mine facilities	20 to 40 years
Oil sands mine equipment	5 to 15 years
Oil sands in situ processing facilities	30 years
Power generation and utility plants	40 years
Refineries, ethanol and lubricants plants	20 to 40 years
Marketing and other distribution assets	20 to 40 years

The costs of major inspection, overhaul and turnaround activities that are capitalized are depreciated on a straight-line basis over the period to the next scheduled activity, which varies from two to five years.

Depreciation, depletion and amortization rates are reviewed annually, or when events or conditions occur that impact capitalized costs, reserves or estimated service lives.

(i) Goodwill and Other Intangible Assets

The company accounts for business combinations using the acquisition method. The excess of the purchase price over the fair value of the identifiable net assets represents goodwill, and is allocated to the cash-generating units (CGUs) or groups of CGUs expected to benefit from the business combination.

Other intangible assets include acquired customer lists and brand value.

Goodwill and brand value have indefinite useful lives and are not subject to amortization. Customer lists are amortized over their expected useful lives, which range from five to 10 years. Expected useful lives of goodwill and other intangible assets are reviewed on an annual basis.

(j) Impairment of Assets

Non-Financial Assets

Intangible assets that have an indefinite useful life are tested annually for impairment. Exploration and evaluation assets are tested for impairment immediately prior to costs being transferred to Property, Plant and Equipment. All other assets are tested for impairment whenever events or changes in circumstance indicate that the carrying amount may not be recoverable.

For the purposes of assessing impairment, assets are grouped into CGUs, defined as the lowest levels for which there are separately identifiable cash inflows. An impairment loss is recognized in Depreciation, Depletion, Amortization and Impairment for the amount by which the carrying amount of the individual asset or CGU exceeds its recoverable amount. The recoverable amount is the higher of the fair value less costs to sell and value-in-use. In determining fair value less costs to sell, recent market transactions are taken into account, if available. In the absence of such transactions, an appropriate valuation model is used. Value-in-use is assessed using the present value of the expected future cash flows of the relevant asset or CGU. Exploration and evaluation assets are tested with the producing CGU for which the activity can be attributed or to the segment level it relates to when a producing CGU does not exist for the exploration and evaluation activity.

Impairments are reversed for all CGUs and individual assets, other than goodwill, to the extent that events or circumstances give rise to changes in the estimate of recoverable amount since the period the impairment was recorded. Impairment reversals are recognized within Depreciation, Depletion, Amortization and Impairment.

Financial Assets

At each reporting date, the company assesses whether there is evidence that a financial asset is impaired. If a financial asset carried at amortized cost is impaired, the amount of the loss is measured as the difference between the amortized cost of the loan or receivable and its recoverable amount. The loss is recognized in Depreciation, Depletion, Amortization and Impairment.

(k) Assets Held For Sale

Assets and liabilities are classified as held for sale if their carrying amounts are expected to be recovered through a disposition rather than through continuing use. The assets or disposal groups are measured at the lower of their carrying amount and fair value less costs to sell. Impairment losses on initial classification as held for sale and subsequent gains or losses on remeasurement are recognized in Loss (Gain) on Disposal of Assets. Assets classified as held for sale are not depreciated, depleted or amortized.

(l) Provisions

Provisions are recognized by the company when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation.

Provisions are recognized for decommissioning and restoration obligations associated with the company's exploration and evaluation assets and property, plant and equipment. Provisions for decommissioning and restoration obligations are measured at the present value of management's best estimate of the future cash flows required to settle the present obligation, using the credit-adjusted risk-free interest rate. The value of the obligation is added to the carrying amount of the associated asset and amortized over the useful life of the asset. The provision is accreted over time through charges to Financing Expenses with actual

expenditures charged against the accumulated obligation. Changes in the future cash flow estimates resulting from revisions to the estimated timing or amount of undiscounted cash flows are recognized as a change in the decommissioning and restoration provision and related asset.

(m) Income Taxes

The company follows the liability method of accounting for income taxes whereby deferred income taxes may be recorded for the effect of differences between the accounting and income tax basis of an asset or liability. Deferred income tax assets and liabilities are measured using enacted or substantively enacted income tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are anticipated to be recovered or settled. Changes to these balances are recognized in earnings or in other comprehensive income in the period they occur. Investment tax credits are recorded as an offset to the related expenditures.

(n) Pensions and Other Post-Retirement Benefits

The company sponsors defined benefit pension plans, defined contribution pension plans and other post-retirement benefits.

Company contributions to the defined contribution pension plans are expensed as incurred. The cost of the defined benefit pension plans and other post-retirement benefits is actuarially determined using the projected unit credit method based on present pay levels and management's best estimates of demographic and financial assumptions. Costs are recorded in Operating, Selling and General expense. Any actuarial gains or losses are recognized immediately through Other Comprehensive Income and transferred directly to Retained Earnings.

The liability recognized on the balance sheet is the present value of the defined benefit obligations less the fair value of plan assets.

(o) Share-Based Compensation Plans

Under the company's share-based compensation plans, share-based awards are granted to executives, employees and non-employee directors. Compensation expense is recorded to Operating, Selling and General expense.

Stock options that give the holder the right to purchase common shares are accounted for as equity-settled plans. The expense is based on the fair value of the options at the time of grant and is recognized over the vesting periods of the respective options. A corresponding increase is recorded to Contributed Surplus. Consideration paid to the company on exercise of options is credited to Share Capital and the associated amount in Contributed Surplus is reclassified to Share Capital.

Share-based compensation awards that settle in cash or have the option to settle in cash or shares are accounted for as cash-settled plans. These are measured at fair value each reporting period and recognized as an expense over the vesting period, with a corresponding adjustment to liabilities. When awards are surrendered for cash, the cash settlement paid reduces the outstanding liability. When awards are exercised for common shares, consideration paid by the holder and the previously recognized liability associated with the options are recorded to Share Capital.

(p) Financial Instruments

All financial instruments are initially recognized at fair value on the balance sheet, net of any transaction costs (except for financial instruments classified as fair value through profit and loss, where transaction costs are expensed as incurred). Subsequent measurement of financial instruments is based on their classification:

Fair Value through Profit and Loss

Financial assets and liabilities that are held for trading or that are designated as fair value through profit and loss upon initial recognition. Changes in their fair value are recognized in earnings.

Loans and Receivables

Non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Measured at amortized cost using the effective interest method.

Held-to-Maturity

Consists of non-derivative financial assets that the company has the intent and ability to hold until maturity. Measured at amortized cost using the effective interest method.

Other Financial Liabilities

Financial liabilities not classified as fair value through profit and loss. Measured at amortized cost using the effective interest method.

Available for Sale

All other non-derivative financial assets are classified as available for sale, with changes in fair value recognized in other comprehensive income.

The company classifies its derivative financial instruments (except those designated as effective hedging instruments) as fair value through profit and loss, its cash and cash equivalents and accounts receivable as loans and receivables, its financial instruments included in other assets as available for sale, and its accounts payable and accrued liabilities, debt, and other long-term liabilities as other financial liabilities.

The company uses derivative financial instruments either to manage certain exposures to fluctuations in interest rates, commodity prices and foreign exchange rates, as part of its overall risk management program, or to earn trading revenues. Earnings impacts from derivatives used to manage a particular risk are reported as part of Other Income in the related operating segment. Gains or losses from trading activities are reported in Other Income as part of Corporate, Energy Trading and Eliminations.

Certain physical commodity contracts are deemed to be derivative financial instruments for accounting purposes. Physical commodity contracts entered into for the purpose of receipt or delivery in accordance with the company's expected purchase, sale or usage requirements are not considered to be derivative financial instruments.

Derivatives embedded in other financial instruments or other host contracts are recorded as separate derivatives when their risks and characteristics are not closely related to those of the host contract.

(q) Hedging Activities

The company may apply hedge accounting to arrangements that qualify for designated hedge accounting treatment. Documentation is prepared at the inception of a hedge relationship in order to qualify for hedge accounting. Designated hedges are assessed at each reporting date to determine if the relationship between the derivative and the underlying hedged exposure is still effective and to quantify any ineffectiveness in the relationship.

If the derivative is designated as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the hedged risk are recognized in earnings. If the derivative is designated as a cash flow hedge, the effective portions of the changes in fair value of the derivative are initially recorded in other comprehensive income and are recognized in earnings when the hedged item is realized. Ineffective portions of changes in the fair value of cash flow hedges are recognized in earnings immediately. Changes in the fair value of a derivative designated in a fair value or cash flow hedge are recognized in the same line item as the underlying hedged item.

(r) Share Capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects.

(s) Dividend Distributions

Dividends on common shares are recognized in the period in which the dividends are approved by the company's Board of Directors.

(t) Earnings per Share

Basic earnings per share is calculated by dividing the net earnings for the period by the weighted-average number of common shares outstanding during the period.

Diluted earnings per share is calculated by adjusting the weighted-average number of common shares outstanding for dilutive common shares related to the company's share-based compensation plans. The number of shares included is computed using the treasury stock method. For share-based compensation plans that may be settled in ordinary shares or cash at the holder's option, the more dilutive of cash settlement and share settlement is used in calculating diluted earnings per share.

4. SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGMENTS

Oil and Gas Reserves and Resources

Certain depletion, depreciation, impairment and decommissioning and restoration charges are measured based on the company's estimate of oil and gas reserves and resources. The estimation of reserves and resources is an inherently complex process and involves the exercise of professional judgment. All reserves and certain resources have been evaluated at December 31, 2011 by independent petroleum consultants in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. The reserves and resources estimates are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook.

Oil and gas reserves and resources estimates are based on a range of geological, technical and economic factors, including projected future rates of production, projected future commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Assumptions reflect market and regulatory conditions existing at December 31, 2011, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Exploration and Evaluation Costs

Certain exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. The company is required to make estimates and judgment about future events and circumstances regarding the economic viability of extracting the underlying resources. The costs are subject to technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. Unsuccessful drilling, or changes to project economics, resource quantities, expected production techniques, production costs and required capital expenditures, are important factors when making this determination. If a judgment is made that the extraction of resources is not viable, the associated exploration and evaluation costs are impaired and charged to net earnings.

Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of exploration and evaluation assets and property, plant and equipment. These provisions are based on estimated costs, which take into account the anticipated method and extent of restoration, technological advances and the possible future use of the site. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience, prices and closure plans. The expected timing of future decommissioning and restoration may change due to certain factors, including reserve life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

Deferred Income Taxes

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the company's estimate, the ability of the company to realize the deferred tax assets could be impacted.

Deferred tax liabilities are recognized when there are taxable temporary differences that will reverse and result in a future outflow of funds to a taxation authority. The company records a provision for the amount that is expected to be settled, which requires the application of judgment as to the ultimate outcome. Deferred tax liabilities could be impacted by changes in the company's estimate of the likelihood of a future outflow, the expected settlement amount, and the tax laws in the jurisdictions in which the company operates.

Pensions and Other Post-Retirement Benefits

The company provides benefits to employees, including pensions and other post-retirement benefits. The cost of defined benefit pension plans and other post-retirement benefits received by employees is determined based on actuarial valuation methods and assumptions. Changes to assumptions related to discount rates, expected return on plan assets and annual rates of compensation increases may have a material impact on the amounts presented.

Impairment of Assets

A cash-generating unit (CGU) is defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructures, and the way in which management monitors the operations.

The recoverable amounts of CGUs and individual assets have been determined based on the higher of fair value less costs to sell or value-in-use calculations. The key assumptions the company uses in estimating future cash flows for recoverable amounts are anticipated future commodity prices, expected production volumes, future operating and development costs, and refining margins. Changes to these assumptions will affect the recoverable amounts of CGUs and individual assets and may then require a material adjustment to their related carrying value.

Derivative Financial Instruments

When not directly observable in active markets, the company uses third-party models and valuation methodologies that utilize observable market data to estimate the fair value of derivative financial instruments. In addition to market information, the company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk.

5. RECENTLY ANNOUNCED ACCOUNTING PRONOUNCEMENTS

Financial Instruments: Recognition and Measurement

In November 2009, as part of the International Accounting Standards Board's (IASB) project to replace International Accounting Standard (IAS) 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the first phase of IFRS 9 *Financial Instruments*. It contained requirements for the classification and measurement of financial assets, and was updated in October 2010 to incorporate financial liabilities. The standard is applicable for annual periods starting on or after January 1, 2015. The full impact of this standard will not be known until the phases addressing hedging and impairments have been completed.

Fair Value Measurements

In May 2011, the IASB issued IFRS 13 *Fair Value Measurement*, which establishes a single source of guidance for all fair value measurements, clarifies the definition of fair value, and enhances the disclosures on fair value measurement. Prospective application of this standard is effective for fiscal years beginning on or after January 1, 2013, with early application permitted. The company does not anticipate significant changes to its fair value measurements and related disclosures as a result of this standard.

Reporting Entity

In May 2011, the IASB issued IFRS 10 *Consolidated Financial Statement*, IFRS 11 *Joint Arrangements*, IFRS 12 *Disclosures of Interests in Other Entities*, and amendments to IAS 27 *Separate Financial Statements* and IAS 28 *Investments in Associates and Joint Ventures*.

IFRS 10 creates a single consolidation model by revising the definition of control in order to apply the same control criteria to all types of entities, including joint arrangements, associates and special purpose vehicles. IFRS 11 establishes a principle-based approach to the accounting for joint arrangements by focusing on the rights and obligations of the arrangement and limits the application of proportionate consolidation accounting to arrangements that meet the definition of a joint operation. IFRS 12 is a comprehensive disclosure standard for all forms of interests in other entities, including joint arrangements, associates and special purpose vehicles.

Retrospective application of these standards with relief for certain transactions is effective for fiscal years beginning on or after January 1, 2013, with earlier application permitted if all five standards are collectively adopted. The company is currently assessing the impact of these standards.

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 *Employee Benefits*, which revises the recognition, presentation and disclosure requirements for defined benefit plans. The revised standard requires immediate recognition of actuarial gains and losses in other comprehensive income, eliminating the previous options that were available, and enhances the disclosure requirements for defined benefit plans. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2013, with early application permitted. The company does not anticipate significant impacts as a result of these amendments.

Production Stripping Costs

In October 2011, the IASB issued International Financial Reporting Interpretation Committee (IFRIC) 20 *Stripping Costs in the Production Phase of a Surface Mine*. This interpretation requires the capitalization and depreciation of stripping costs in the production phase if an entity can demonstrate that it is probable that future economic benefits will be realized, the costs can be reliably measured and the entity can identify the component of the ore body for which access has been improved. Retrospective application of this interpretation is effective for annual periods beginning on or after January 1, 2013, with earlier application permitted. The company does not anticipate significant impacts as a result of this interpretation.

6. FIRST-TIME ADOPTION OF IFRS

Effective January 1, 2011, the company began reporting under IFRS, and the accounting policies disclosed in note 3 to these consolidated financial statements have been applied in preparing the financial statements for the years ended December 31, 2011 and 2010 and in the preparation of the company's opening balance sheet at January 1, 2010 (Transition Date).

In previous years, the company prepared its consolidated financial statements in accordance with Previous GAAP. Reconciliations from Previous GAAP to IFRS for comparative periods are provided on the following pages.

Reconciliation of Equity at December 31, 2010

($ millions)	Previous GAAP [1]	Presentation Changes for Discontinued Operations [2]	Other Presentation Changes [3]	IFRS Adjustments [4]	IFRS
Assets					
Current assets					
Cash and cash equivalents	1 077	—	—	—	1 077
Accounts receivable	5 253	—	—	—	5 253
Inventories	3 141	—	—	—	3 141
Income taxes receivable	734	—	—	—	734
Deferred income taxes	210	—	(210)	—	—
Assets held for sale [5]	98	658	—	6	762
Total current assets	10 513	658	(210)	6	10 967
Property, plant and equipment, net [5][6][7][8][9][10][14]	55 290	—	(3 961)	(1 371)	49 958
Exploration and evaluation	—	—	3 961	—	3 961
Other assets	451	—	(221)	—	230
Goodwill	3 201	—	(3 201)	—	—
Goodwill and other intangible assets	—	—	3 422	—	3 422
Deferred income taxes	56	—	13	—	69
Assets of discontinued operations	658	(658)	—	—	—
Total assets	70 169	—	(197)	(1 365)	68 607
Liabilities and Shareholders' Equity					
Current liabilities					
Short-term debt	2	—	1 982	—	1 984
Current portion of long-term debt	518	—	—	—	518
Accounts payable and accrued liabilities [11][12]	6 942	—	(604)	105	6 443
Current portion of provisions	—	—	604	4	608
Income taxes payable	929	—	—	—	929
Deferred income taxes	37	—	(37)	—	—
Liabilities associated with assets held for sale [5][6][14]	98	484	—	4	586
Total current liabilities	8 526	484	1 945	113	11 068
Long-term debt [7]	11 669	—	(1 982)	142	9 829
Accrued liabilities and other	4 154	—	(4 154)	—	—
Other long-term liabilities [11][12]	—	—	1 861	242	2 103
Provisions [5][6]	—	—	2 293	211	2 504
Deferred income taxes [14]	8 615	—	(160)	(544)	7 911
Liabilities of discontinued operations	484	(484)	—	—	—
Shareholders' equity [5][6][7][8][9][10][11][12][13][14]	36 721	—	—	(1 529)	35 192
Total liabilities and shareholders' equity	70 169	—	(197)	(1 365)	68 607

See footnotes starting on page 98.

Reconciliation of Equity at January 1, 2010

($ millions)	Previous GAAP [1]	Presentation Changes [3]	IFRS Adjustments [4]	IFRS
Assets				
Current assets				
Cash and cash equivalents	505	—	—	505
Accounts receivable	3 936	—	—	3 936
Inventories	2 971	—	—	2 971
Income taxes receivable	587	—	—	587
Deferred income taxes	332	(332)	—	—
Total current assets	8 331	(332)	—	7 999
Property, plant and equipment, net [5][7][8][9][14]	57 485	(4 297)	(1 632)	51 556
Exploration and evaluation	—	4 342	—	4 342
Other assets	536	(277)	—	259
Goodwill	3 201	(3 201)	—	—
Goodwill and other intangible assets	—	3 433	—	3 433
Deferred income taxes	193	17	—	210
Total assets	69 746	(315)	(1 632)	67 799
Liabilities and Shareholders' Equity				
Current liabilities				
Short-term debt	2	2 315	—	2 317
Current portion of long-term debt	25	—	—	25
Accounts payable and accrued liabilities [11][12]	6 529	(882)	126	5 773
Current portion of provisions	—	882	—	882
Income taxes payable	1 274	—	—	1 274
Deferred income taxes	18	(18)	—	—
Total current liabilities	7 848	2 297	126	10 271
Long-term debt [7]	13 855	(2 315)	139	11 679
Accrued liabilities and other	5 062	(5 062)	—	—
Other long-term liabilities [11][12]	—	2 053	20	2 073
Provisions [5]	—	3 009	296	3 305
Deferred income taxes [14]	8 870	(297)	(587)	7 986
Shareholders' equity [5][7][8][9][11][12][13][14]	34 111	—	(1 626)	32 485
Total liabilities and shareholders' equity	69 746	(315)	(1 632)	67 799

See footnotes starting on page 98.

Reconciliation of Comprehensive Income for the Year Ended December 31, 2010

($ millions)	Previous GAAP [1]	Presentation Changes for Discontinued Operations [2]	Other Presentation Changes [3]	IFRS Adjustments [4]	IFRS
Revenues and Other Income					
Operating revenues	33 198	911	(2 106)	—	32 003
Less: Royalties	(1 937)	(41)	1 978	—	—
Operating revenues, net of royalties	31 261	870	(128)	—	32 003
Other income	491	—	110	—	601
	31 752	870	(18)	—	32 604
Expenses					
Purchases of crude oil and products	14 911	(62)	(18)	—	14 831
Operating, selling and general [7][11][12]	7 810	185	—	(11)	7 984
Transportation	656	47	—	—	703
Depreciation, depletion, amortization and impairment [5][7][8][9][10]	3 813	264	—	(274)	3 803
Accretion of asset retirement obligations	178	27	(205)	—	—
Exploration	197	21	—	—	218
Gain on disposal of assets [6]	(107)	(814)	—	(54)	(975)
Project start-up costs	77	—	—	—	77
Financing expenses (income) [5][7]	(30)	18	205	(6)	187
	27 505	(314)	(18)	(345)	26 828
Earnings before Income Taxes	4 247	1 184	—	345	5 776
Income Taxes					
Current	1 004	192	—	—	1 196
Deferred [14]	555	109	—	87	751
	1 559	301	—	87	1 947
Net Earnings from Continuing Operations	2 688	883	—	258	3 829
Net Earnings from Discontinued Operations	883	(883)	—	—	—
Net Earnings	3 571	—	—	258	3 829
Other Comprehensive Income (Loss)					
Foreign currency translation adjustment [5][11]	(503)	—	63	3	(437)
Foreign currency translation adjustment relating to assets held for sale	—	—	(63)	—	(63)
Foreign currency translation reclassified to net earnings [6]	53	—	—	(4)	49
Cash flow hedges reclassified to net earnings	(1)	—	—	—	(1)
Actuarial loss on employee retirement benefit plans [11][14]	—	—	—	(152)	(152)
Other Comprehensive Loss	(451)	—	—	(153)	(604)
Total Comprehensive Income	3 120	—	—	105	3 225

See footnotes starting on page 98.

Explanation of Significant Adjustments

(1) Represents amounts reported under Previous GAAP. Previous GAAP balances as at January 1, 2010 agree to December 31, 2009 balances reported in the company's 2009 Annual Report.

Energy Supply and Trading Activities Income and Expenses have been reclassified to conform to net basis presentation adopted in the second quarter of 2011, with net amounts now recorded in Other Income (see note 8).

(2) Certain assets held for sale reported as discontinued operations under Previous GAAP are not classified as such under IFRS.

(3) Represents other presentation changes to comply with IFRS. A description of significant reclassifications is as follows:

- Exploration and Evaluation assets reported within Property, Plant and Equipment under Previous GAAP are reflected as a separate line under IFRS.
- Short-term debt instruments supported by a revolving credit facility with a separate lender are classified as Short-Term Debt under IFRS. These short-term debt instruments were classified as Long-Term Debt under Previous GAAP.
- Liabilities encompassing significant uncertainty in timing or amount are reported as Provisions under IFRS. Under Previous GAAP, these liabilities were classified within Accounts Payable and Accrued Liabilities, and Accrued Liabilities and Other.

There were no presentation changes made to the Consolidated Statements of Cash Flows.

(4) Represents the impact on financial statements of transition to IFRS from Previous GAAP, except for presentation changes. The significant adjustments are described below, with the resulting impacts on income taxes described in paragraph (14).

(5) *Decommissioning and Restoration*

Under Previous GAAP, increases in the estimated cash flows were discounted using the current credit-adjusted risk-free rate, while downward revisions in the estimated cash flows were discounted using the credit-adjusted risk-free rate that existed when the original liability was recognized. Under IFRS, estimated cash flows are discounted using the credit-adjusted risk-free rate that exists at the balance sheet date.

In accordance with IFRS 1, the company elected to remeasure its decommissioning and restoration costs at the Transition Date and has estimated the related asset by discounting the liability to the date in which the liability arose and recalculated the accumulated depreciation, depletion and amortization under IFRS. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Assets held for sale	6	—
Property, plant and equipment, net	(688)	(690)
Liabilities associated with assets held for sale	27	—
Provisions	217	296
Foreign currency translation	1	—
Retained earnings	(927)	(986)
Depreciation, depletion, amortization and impairment	(40)	—
Financing expenses (income)	(19)	—
Foreign currency translation adjustment	1	—

(6) *Dispositions*

The net carrying values of disposed properties have been adjusted to reflect their respective IFRS adjustments, resulting in revised gains or losses upon disposal of the assets. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	22	—
Liabilities associated with assets held for sale	(18)	—
Provisions	(10)	—
Foreign currency translation	(4)	—
Retained earnings	54	—
Gain on disposal of assets	(54)	—
Foreign currency translation reclassified to net earnings	(4)	—

(7) *Leases*

In accordance with IFRS 1, the company elected to evaluate whether certain arrangements contain a lease based on the facts and circumstances existing at Transition Date. Pursuant to such evaluation, the company has accounted for certain arrangements as finance leases under IFRS. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	101	103
Long-term debt	142	139
Retained earnings	(41)	(36)
Operating, selling and general	(13)	—
Depreciation, depletion, amortization and impairment	5	—
Financing expenses (income)	13	—

(8) *Derecognition of Assets*

Under Previous GAAP, carrying amounts of property, plant and equipment assets were derecognized when no future economic benefits were expected from their use. Under IFRS, this derecognition of assets occurs at the component level. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	(141)	(113)
Retained earnings	(141)	(113)
Depreciation, depletion, amortization and impairment	28	—

(9) *Fair Value as Deemed Cost*

The company has applied the IFRS 1 election to record certain assets of property, plant and equipment at fair value on the Transition Date. The exemption has been applied to refinery assets located in Eastern Canada and certain natural gas assets in Western Canada. When estimating fair value, market information for similar assets was used, and where market information was not available, management relied on internally generated cash flow models using discount rates specific to the asset and long-term forecasts of commodity prices and refining margins. The aggregate of these fair values was $1.370 billion, resulting in a reduction of the carrying amount of property, plant and equipment as at January 1, 2010. Under Previous GAAP, impairment losses were recorded in the third quarter of 2010 for certain of these natural gas properties. There were no impairment losses recognized during 2010 under IFRS, as these properties were adjusted to fair value at the Transition Date. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	(527)	(906)
Retained earnings	(527)	(906)
Depreciation, depletion, amortization and impairment	(379)	—

(10) *Impairment of Assets*

Under Previous GAAP, an item of property, plant and equipment is deemed recoverable if the undiscounted future cash flows exceed the net carrying amount of the asset group. Under IFRS, recoverability of property, plant and equipment is based on the higher of fair value less costs to sell and value in use of the CGU.

Under IFRS, the company recognized impairment losses for certain CGUs within the Exploration and Production operating segment during 2010. The impaired natural gas assets are located within the Western Canadian Sedimentary Basin and were grouped into CGUs based on similar geological structure, shared infrastructure and similar exposure to market risks. Declining long-term natural gas prices have resulted in the carrying amounts for these CGUs exceeding their recoverable amounts. Recoverable amounts have been determined using the fair value less costs to sell method and based on internally generated

cash flow projections. In determining fair value less costs to sell, the company considered recent transactions within the industry, long-term views of natural gas prices, externally evaluated reserve volumes, and discount rates specific to the asset. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	(112)	—
Retained earnings	(112)	—
Depreciation, depletion, amortization and impairment	112	—

(11) *Employee Benefits*

Under Previous GAAP, unamortized actuarial gains and losses in respect of the company's defined benefit pension plans were recognized into earnings over the expected average remaining service life of employees. In accordance with IFRS 1, the company has elected to recognize all cumulative actuarial gains and losses directly in Retained Earnings at the Transition Date. Under IFRS, actuarial gains and losses incurred in the period are recorded in Other Comprehensive Income and then transferred directly to Retained Earnings.

Under Previous GAAP, the expense recognition period for other post-retirement benefit plans began on the employee's date of hire. Under IFRS, this period now commences when the employee reaches 45 years of age, the point at which the employee first starts accruing benefits under these plans.

The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Accounts payable and accrued liabilities	10	15
Other long-term liabilities	215	15
Foreign currency translation	2	—
Retained earnings	(227)	(30)
Operating, selling and general	(4)	—
Foreign currency translation adjustment	2	—
Actuarial loss on employee retirement benefit plans	(201)	—

(12) *Share-Based Compensation*

Under Previous GAAP, the company recorded obligations for cash-settled share-based compensation plans using the intrinsic value method. Under IFRS, obligations for these same plans are recorded as a liability using the fair value method. For equity-settled share-based compensations plans, the company accrues the cost of employee stock options over the vesting period using the graded method of amortization rather than the straight-line method, which the company used under Previous GAAP. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Accounts payable and accrued liabilities	95	111
Other long-term liabilities	27	5
Contributed surplus	2	10
Retained earnings	(124)	(126)
Operating, selling and general	(2)	—

(13) *Foreign Exchange*

In accordance with IFRS 1, the company elected at the Transition Date to transfer all foreign currency translation differences in respect of foreign operations that arose prior to the Transition Date to Retained Earnings. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Foreign currency translation	248	248
Retained earnings	(248)	(248)

(14) *Income Taxes*

The company recognized deferred income taxes primarily in respect of the above changes. The impacts on the financial statements were as follows:

($ millions)	As at and for the year ended Dec 31, 2010	As at Jan 1, 2010
Property, plant and equipment, net	(26)	(26)
Liabilities associated with assets held for sale	(5)	—
Deferred income taxes – liability	(544)	(587)
Retained earnings	523	561
Deferred income taxes – expense	87	—
Actuarial loss on employee retirement benefit plans	49	—

(15) *Earnings per Common Share*

Under Previous GAAP, the dilutive impact of options with tandem stock appreciation rights or cash payment alternatives was not included in the calculation of diluted earnings per share. Under IFRS, these awards are considered potentially dilutive and are included in the calculation of the company's diluted net earnings per share calculation if they have a dilutive impact in the period.

The impact on the net earnings amount used in the calculation of diluted earnings per share for the year ended December 31, 2010 can be seen in note 13.

(16) In addition to the IFRS 1 elections described in this note, the company has also applied the following elections:

- Business combinations and acquisitions of interests in associates and joint ventures that occurred prior to the Transition Date were not restated in accordance with IFRS. An impairment test of associated goodwill was performed as at the Transition Date and no impairment losses were identified.
- Borrowing costs capitalized for qualifying projects prior to the Transition Date were not restated for the specific measurement rules required by IFRS.

7. SEGMENTED INFORMATION

The company's operating segments are reported based on the nature of their products and services. The following summary describes the operations in each of the segments:

- Oil Sands includes the company's operations in northeast Alberta to develop and produce synthetic crude oil and related products, through the recovery and upgrading of bitumen from mining and in situ operations. This segment also includes the company's 12% ownership interest in the Syncrude oil sands mining and upgrading joint venture, located near Fort McMurray, Alberta.
- Exploration and Production includes exploration and production of natural gas, crude oil and natural gas liquids in Western Canada, offshore activity in East Coast Canada, with interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields, and the exploration and production of crude oil and natural gas in the United Kingdom (U.K.), Norway, Libya and Syria.
- Refining and Marketing includes the refining of crude oil products, and the distribution and marketing of these and other purchased products through refineries located in Canada and the United States (U.S.), as well as a lubricants plant located in Eastern Canada.

The company also reports activities not directly attributable to an operating segment under Corporate, Energy Trading and Eliminations. This includes investments in renewable energy projects, and results relating to energy trading activities.

In the first quarter of 2011, the company combined its International and Offshore and Natural Gas segments into one new segment, Exploration and Production. All prior periods have been reclassified to conform to these segment definitions.

Intersegment sales of crude oil and natural gas are accounted for at market values and included, for segmented reporting, in revenues of the segment making the transfer and expenses of the segment receiving the transfer. Intersegment amounts are eliminated on consolidation. The company has one customer that individually represents 11% of the consolidated revenues for the year ended December 31, 2011. No other customers represent more than 10% of the consolidated revenues for the year ended December 31, 2011 (2010 – nil).

For the years ended December 31 ($ millions)	Oil Sands		Exploration and Production		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
	2011	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Revenues and Other Income										
Gross revenues	**9 581**	7 052	**6 293**	6 326	**25 657**	20 653	**77**	30	**41 608**	34 061
Intersegment revenues	**3 420**	2 638	**491**	717	**56**	207	**(3 967)**	(3 562)	**—**	—
Less: Royalties	**(799)**	(681)	**(1 472)**	(1 377)	**—**	—	**—**	—	**(2 271)**	(2 058)
Operating revenues, net of royalties	**12 202**	9 009	**5 312**	5 666	**25 713**	20 860	**(3 890)**	(3 532)	**39 337**	32 003
Other income	**31**	415	**(3)**	261	**58**	21	**367**	(96)	**453**	601
	12 233	9 424	**5 309**	5 927	**25 771**	20 881	**(3 523)**	(3 628)	**39 790**	32 604
Expenses										
Purchases of crude oil and products	**1 381**	1 070	**585**	240	**20 547**	16 920	**(3 790)**	(3 399)	**18 723**	14 831
Operating, selling and general	**5 169**	4 537	**850**	933	**2 182**	2 200	**223**	314	**8 424**	7 984
Transportation	**399**	291	**116**	230	**219**	200	**2**	(18)	**736**	703
Depreciation, depletion, amortization and impairment	**1 374**	1 310	**2 035**	1 978	**444**	440	**99**	75	**3 952**	3 803
Exploration	**56**	6	**60**	212	**—**	—	**—**	—	**116**	218
Loss (gain) on disposal of assets	**122**	14	**31**	(998)	**(16)**	(30)	**(1)**	39	**136**	(975)
Project start-up costs	**163**	74	**—**	3	**—**	—	**—**	—	**163**	77
Financing expenses (income)	**74**	104	**65**	78	**13**	11	**319**	(6)	**471**	187
	8 738	7 406	**3 742**	2 676	**23 389**	19 741	**(3 148)**	(2 995)	**32 721**	26 828
Earnings (Loss) before Income Taxes	**3 495**	2 018	**1 567**	3 251	**2 382**	1 140	**(375)**	(633)	**7 069**	5 776
Income taxes	**892**	498	**1 261**	1 313	**656**	321	**(44)**	(185)	**2 765**	1 947
Net Earnings (Loss)	**2 603**	1 520	**306**	1 938	**1 726**	819	**(331)**	(448)	**4 304**	3 829
Capital and Exploration Expenditures	**5 100**	3 709	**874**	1 274	**633**	667	**243**	360	**6 850**	6 010

Total Assets ($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Oil Sands	**44 217**	39 382	36 657
Exploration and Production	**14 290**	15 899	19 218
Refining and Marketing	**13 150**	11 292	9 748
Corporate, Energy Trading and Eliminations	**3 120**	2 034	2 176
	74 777	68 607	67 799

Geographical Information

Operating Revenues, net of Royalties ($ millions)	**2011**	2010
Canada	**31 876**	24 053
Foreign	**7 461**	7 950
	39 337	32 003

Non-Current Assets [1] ($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Canada	**53 794**	50 033	50 348
Foreign	**6 799**	7 538	9 234
	60 593	57 571	59 582

(1) Excludes deferred income tax assets.

8. OTHER INCOME

Other Income consists of the following:

($ millions)	**2011**	2010
Risk management activities	**(22)**	89
Energy trading activities [1]		
Change in fair value of contracts	**301**	106
Unrealized losses on inventory valuation	**(19)**	(4)
Investment and interest income	**141**	44
Renewable energy grants	**64**	36
Other	**(12)**	35
Terra Nova redetermination [2]	**—**	295
	453	601

(1) In the second quarter of 2011, the company completed a review of its energy supply and trading activities. It was determined that the nature and purpose of transactions previously presented on a gross basis in Energy Supply and Trading Activities income and expenses in the Consolidated Statements of Comprehensive Income have evolved such that they are more appropriately reflected through net presentation. Realized and unrealized gains and losses, and the underlying settlement of these contracts, is now recognized and recorded on a net basis.

Prior period comparative figures have been reclassified for comparability with the current period presentation. The impact is as follows:

($ millions, increase/(decrease))	Year ended December 31, 2010
Energy supply and trading activities income	(2 700)
Other income	102
Energy supply and trading activities expenses	(2 598)
Net earnings	—

(2) In 2010, the joint owners of the Terra Nova oilfield finalized the redetermination of working interests 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 agreed to reimburse the company for its increased working interest from February 1, 2005 to December 31, 2010. As a result, the company recognized income of $295 million in 2010.

9. OPERATING, SELLING AND GENERAL

Operating, Selling and General expense consists of the following:

($ millions)	**2011**	2010
Contract services	**4 107**	3 997
Employee benefits [1]	**2 062**	2 149
Materials	**882**	1 175
Energy	**712**	546
Other	**661**	117
	8 424	7 984

(1) The company incurred $2.5 billion of employee benefits costs for the year ended December 31, 2011 (2010 – $2.4 billion), of which $2.1 billion (2010 – $2.1 billion) was recorded as employee benefits expense in Operating, Selling and General expense. Employee benefits expense includes salaries, benefits and share-based compensation.

10. ASSET IMPAIRMENT

Libya

In the second quarter of 2011, the company recognized impairment losses of $514 million related to Libyan assets in its Exploration and Production business. At that time, production had been shut-in due to political violence in Libya.

In calculating the company's impairment in the second quarter of 2011, the recoverable amount was determined using a value-in-use methodology. The company used an expected cash flow approach based on 2010 year-end reserves data updated for current price forecasts, with three scenarios representing i) resumption of normal operations after one year, ii) resumption of

normal operations after two years, and iii) total loss. These scenarios were probability-weighted based on the company's best estimates, and present valued using a risk-adjusted discount rate of 17%. The two scenarios where the company resumes production incorporated rebuilding costs.

The impairment losses were recorded as part of Depreciation, Depletion, Amortization and Impairment expense in the Consolidated Statements of Comprehensive Income, and charged against Property, Plant and Equipment ($259 million), Exploration and Evaluation assets ($211 million), and Inventories ($44 million) in the Consolidated Balance Sheets.

During the third quarter of 2011, a change in the Libyan government resulted in the lifting of certain sanctions that were impacting the company's operations in the country. In the fourth quarter of 2011, the company's joint venture partner restarted production in certain fields, and in January 2012 the company started to receive production payments. In addition, the joint venture partner confirmed the existence of crude oil written off in the second quarter of 2011, and the company reversed the $11 million impairment charge that related to crude oil inventories.

Discussions with the Libyan authorities have commenced on the status of existing contract terms, including production volumes and time frames for future exploration commitments. However, there is unpredictability around current production levels and ramp-up expectations, and the extent of the damage to the company's assets has not yet been fully assessed. Therefore, at December 31, 2011, there has been no change in the company's overall assessment of the impairment, and no reversal of impairment has been recognized except for the $11 million crude oil inventories.

Syria

In December 2011, the company suspended its operations with the Syrian General Petroleum Company and ceased recording production or revenues. These actions were taken as a result of sanctions announced by the European Union on December 2, 2011.

An impairment test was performed on the company's Syrian assets, which determined that the assets were not impaired at December 31, 2011. The recoverable amount was determined using the value-in-use methodology. The company used an expected cash flow approach based on current price forecasts and 2011 year-end reserves data, which take into account the long-term nature of natural gas reserves associated with these assets. The company used four scenarios representing i) resumption of normal operations after six months, ii) resumption of normal operations after one year, iii) resumption of normal operations after two years, and iv) total loss. These scenarios were probability-weighted based on the company's best estimates, and present valued using a risk-adjusted discount rate of 17%. The three scenarios where the company resumes normal operations assume that upon return the company will receive payment for any production during its absence.

The calculation of value-in-use is most sensitive to management's assumption on the timing of resumption of normal operations. If the probability weighting in the cash flow model was adjusted to reflect no probability of the company resuming normal operations within the next twelve months, the company's Syrian assets may be impaired.

The carrying value of the company's net assets in Syria at December 31, 2011 was approximately $900 million.

Other

During the fourth quarter of 2011, the company recognized a write-down of $100 million related to certain natural gas CGUs in the Exploration and Production business due to a decrease in price forecasts. The recoverable amount was determined using a fair value less costs to sell methodology, with the expected future cash flows based on 2011 year-end reserves data with third-party price forecasts and a discount rate of 12%.

During the second quarter of 2010, the company recognized a write-down of $189 million related to certain extraction equipment in the Oil Sands operating segment. These assets were being used in the development of an alternative extraction process to crush and slurry oil sands at the mine face, which the company has discontinued. Also during the second quarter of 2010, the company recognized a write-down of $44 million of certain land leases in the Exploration and Production operating segment. These assets are in areas of Western Canada and Alaska that the company does not plan to pursue given its strategic business alignment.

During the third quarter of 2010, the company recognized a write-down of $106 million related to certain North Sea assets in the Exploration and Production operating segment. An agreement to sell these assets was entered into during the quarter and the assets were written down to reflect fair value less cost to sell.

During the fourth quarter of 2010, the company recognized a charge of $112 million to reflect the write-down of certain assets in the Exploration and Production operating segment to reflect fair value based on discounted future cash flows.

These charges are included in Depreciation, Depletion, Amortization and Impairment expense in the Consolidated Statements of Comprehensive Income.

11. FINANCING EXPENSES

($ millions)	**2011**	2010
Interest on debt	**661**	704
Capitalized interest at 6.0% (2010 – 5.4%)	**(559)**	(301)
Interest expense	**102**	403
Accretion	**157**	235
Foreign exchange loss (gain) on U.S. dollar denominated long-term debt	**183**	(426)
Other foreign exchange loss (gain)	**29**	(25)
Total financing expenses	**471**	187

12. INCOME TAXES

Income Tax Expense

($ millions)	**2011**	2010
Current:		
Current year	**1 103**	1 172
Adjustments for prior years	**18**	24
Deferred:		
Origination and reversal of temporary differences	**1 258**	770
Adjustments for prior years	**(56)**	(4)
Changes in tax rates and legislation	**442**	(15)
	2 765	1 947

Tax Recognized in Other Comprehensive Income

($ millions)	**2011**	2010
Employee retirement benefit plans	**(117)**	(49)
	(117)	(49)

There was no income tax recognized directly in equity during 2010 and 2011.

Reconciliation of Effective Tax Rate

The provision for income taxes reflects an effective tax rate that differs from the statutory tax rate. A reconciliation of the difference is as follows:

($ millions)	**2011**	2010
Earnings before income tax	**7 069**	5 776
Canadian statutory tax rate	**27.19%**	28.91%
Statutory tax	**1 922**	1 670
Add (deduct) the tax effect of:		
Non-taxable component of capital gains and losses	**(33)**	(67)
Share-based compensation and other permanent items	**34**	1
Assessments and adjustments	**(38)**	20
Impact of income tax rate and legislative changes [(1)]	**442**	(15)
Canadian tax rate differential	**(116)**	(106)
Foreign tax rate differential	**383**	440
Non-taxable Libyan impairment charge	**142**	—
Other	**29**	4
	2 765	1 947

(1) In March 2011, the U.K. government substantively enacted a 12% increase in the supplementary charge on U.K. oil and gas profits. Accordingly, in the first quarter of 2011, the company recognized an increase in deferred tax expense of $442 million related to the revaluation of deferred income tax balances.

Deferred Income Tax Balances

Deferred income tax expense and net liabilities in the company's financial statements were comprised of the following:

	Consolidated Statements of Comprehensive Income		Consolidated Balance Sheets [1]		
($ millions)	**2011**	2010	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Property, plant and equipment	**967**	612	**10 725**	9 453	9 236
Risk management and energy trading	**—**	27	**9**	27	—
Decommissioning and restoration provision	**205**	178	**(507)**	(713)	(891)
Employee retirement benefit plans	**73**	(50)	**(518)**	(492)	(393)
Tax loss carry-forwards	**(213)**	(251)	**(558)**	(372)	—
Partnership deferral reserve	**594**	—	**594**	121	—
Other	**18**	235	**(86)**	(182)	(176)
	1 644	751	**9 659**	7 842	7 776

(1) The deferred income tax liability of $9.719 billion at December 31, 2011 (December 31, 2010 – $7.911 billion, January 1, 2010 – $7.986 billion) includes $9.713 billion (December 31, 2010 – $7.911 billion, January 1, 2010 – $7.724 billion) that will be settled beyond the next twelve months.

The deferred income tax asset of $60 million at December 31, 2011 (December 31, 2010 – $69 million, January 1, 2010 – $210 million) includes $47 million (December 31, 2010 – $51 million, January 1, 2010 – $94 million) that will be recovered beyond the next twelve months.

Change in Deferred Income Tax Balances

($ millions)	**2011**	2010
Beginning of year	**7 842**	7 776
Recognized in deferred income tax expense	**1 644**	751
Recognized in other comprehensive income	**(117)**	(49)
Other	**290**	(636)
End of year	**9 659**	7 842

No deferred tax liability has been recognized at December 31, 2011 on temporary differences of approximately $9 billion (2010 – $8 billion) associated with earnings retained in our investments in foreign subsidiaries, as the company is able to control the timing of the reversal of these differences. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional income tax expense. Deferred distribution taxes associated with international business operations have not been recorded.

13. EARNINGS PER COMMON SHARE

($ millions)	**2011**	2010
Net earnings	**4 304**	3 829
Dilutive impact of accounting for awards as equity-settled [1]	**(86)**	(6)
Net earnings – diluted	**4 218**	3 823
(millions of common shares)		
Weighted-average number of common shares	**1 571**	1 562
Dilutive securities:		
Effect of share options	**11**	14
Weighted-average number of diluted common shares	**1 582**	1 576
(dollars per common share)		
Basic earnings per share	**2.74**	2.45
Diluted earnings per share	**2.67**	2.43

(1) Options with tandem stock appreciation rights or cash payment alternatives are accounted for as cash-settled plans. As these awards can be exchanged for common shares of the company, they are considered potentially dilutive and are included in the calculation of the company's diluted net earnings per share calculation if they have a dilutive impact in the period. Accounting for these awards as equity-settled was determined to have the most dilutive impact for the years ended December 31, 2011 and 2010.

14. CASH AND CASH EQUIVALENTS

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Cash	**832**	358	205
Cash equivalents	**2 971**	719	300
	3 803	1 077	505

15. SUPPLEMENTAL CASH FLOW INFORMATION

The (increase) decrease in non-cash working capital is comprised of:

($ millions)	**2011**	2010
Accounts receivable	**(263)**	(568)
Inventories	**(1 064)**	(190)
Accounts payable and accrued liabilities	**1 322**	130
Provisions	**203**	(274)
Income taxes payable/receivable	**70**	(461)
Total	**268**	(1 363)
Relating to:		
Operating activities	**242**	(1 170)
Investing activities	**26**	(193)

16. INVENTORIES

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Crude oil	**1 321**	916	781
Refined products	**1 741**	1 289	1 303
Materials, supplies and merchandise	**592**	564	532
Energy trading commodity inventories	**551**	372	355
Total [(1)]	**4 205**	3 141	2 971

(1) At December 31, 2010, inventories of $11 million were reclassified to assets held for sale.

During 2011, product inventories of $18.7 billion (2010 – $14.8 billion) were expensed. There was a write-down of inventories of $33 million in 2011 – see note 10 (2010 – $nil).

17. ASSETS HELD FOR SALE

In the first quarter of 2011, the company completed the sale of certain non-core U.K. offshore assets for net proceeds of £90 million (Cdn$140 million). In the second and third quarters of 2011, the company completed the sale of certain non-core assets located in northern Alberta and northeast British Columbia for net proceeds of $164 million. The company recognized a loss of $31 million on these disposals in 2011.

During 2010, the company completed the sale of a number of non-core North American oil and gas properties for net proceeds of approximately $1.7 billion. The company also completed the disposition of certain international operations, including its shares in Petro-Canada Netherlands BV, assets in Trinidad and Tobago, and certain U.K. offshore assets, for net proceeds of approximately $900 million. The company recognized a gain of $868 million on these disposals in 2010.

The company had no assets or liabilities classified as assets held for sale at December 31, 2011 or January 1, 2010. The assets and liabilities classified as held for sale at December 31, 2010 were as follows:

($ millions)	Dec 31 2010
Assets	
Current assets	98
Property, plant and equipment, net	635
Exploration and evaluation	29
	762
Liabilities	
Current liabilities	98
Provisions	311
Deferred income taxes	177
	586

18. PROPERTY, PLANT AND EQUIPMENT

($ millions)	Oil and Gas Properties	Plant and Equipment	**Total**
Cost			
At January 1, 2010	19 947	39 179	59 126
Additions	1 363	4 356	5 719
Transfers from exploration and evaluation	3	—	3
Changes in decommissioning and restoration	(67)	18	(49)
Disposals	(2 947)	(739)	(3 686)
Transfers to assets held for sale	(711)	—	(711)
Foreign exchange adjustments	(607)	(97)	(704)
At December 31, 2010	16 981	42 717	59 698
Additions	**1 358**	**4 952**	**6 310**
Transfers from exploration and evaluation	**237**	**—**	**237**
Acquisitions (note 33)	**—**	**126**	**126**
Changes in decommissioning and restoration	**1 862**	**15**	**1 877**
Disposals	**(405)**	**(2 717)**	**(3 122)**
Foreign exchange adjustments	**256**	**50**	**306**
At December 31, 2011	**20 289**	**45 143**	**65 432**
Accumulated provision			
At January 1, 2010	(2 076)	(5 494)	(7 570)
Depreciation and depletion	(1 647)	(1 441)	(3 088)
Impairment	(218)	—	(218)
Disposals	795	208	1 003
Transfers to assets held for sale	76	—	76
Foreign exchange adjustments	42	15	57
At December 31, 2010	(3 028)	(6 712)	(9 740)
Depreciation and depletion	**(1 622)**	**(1 770)**	**(3 392)**
Impairment	**(359)**	**—**	**(359)**
Disposals	**316**	**356**	**672**
Foreign exchange adjustments	**(13)**	**(11)**	**(24)**
At December 31, 2011	**(4 706)**	**(8 137)**	**(12 843)**
Net property, plant and equipment			
January 1, 2010	17 871	33 685	51 556
December 31, 2010	13 953	36 005	49 958
December 31, 2011	**15 583**	**37 006**	**52 589**

($ millions)	Dec 31, 2011 Cost	Accumulated provision	Net property, plant and equipment	Dec 31, 2010 Cost	Accumulated provision	Net property, plant and equipment
Oil Sands	**41 679**	**(6 548)**	**35 131**	37 485	(5 206)	32 279
Exploration and Production	**13 757**	**(4 018)**	**9 739**	12 822	(2 522)	10 300
Refining and Marketing	**8 834**	**(1 953)**	**6 881**	8 491	(1 776)	6 715
Corporate, Energy Trading and Eliminations	**1 162**	**(324)**	**838**	900	(236)	664
	65 432	**(12 843)**	**52 589**	59 698	(9 740)	49 958

At December 31, 2011, the balance of assets under construction, and not subject to depreciation or depletion, was $16.2 billion (December 31, 2010 – $15.9 billion, January 1, 2010 – $15.1 billion).

At December 31, 2011, property, plant and equipment included finance leases with a net book value of $425 million (December 31, 2010 – $403 million, January 1, 2010 – $376 million).

19. EXPLORATION AND EVALUATION ASSETS

($ millions)	2011	2010
Beginning of year	**3 961**	4 342
Acquisitions	**716**	—
Additions	**657**	275
Transfers to oil and gas assets	**(237)**	(3)
Dry hole expenses	**(21)**	(45)
Disposals	**(263)**	(342)
Impairment (note 10)	**(211)**	(44)
Amortization	**(44)**	(54)
Transfers to assets held for sale	**—**	(29)
Foreign exchange adjustments	**(4)**	(139)
End of year	**4 554**	3 961

20. OTHER ASSETS

($ millions)	Dec 31 2011	Dec 31 2010	Jan 1 2010
Investments	**228**	135	148
Other	**83**	95	111
	311	230	259

21. GOODWILL AND OTHER INTANGIBLE ASSETS

($ millions)	Oil Sands Goodwill	Refining and Marketing Goodwill	Brand name	Customer lists	Total
At January 1, 2010	3 019	182	166	66	3 433
Amortization	—	—	—	(11)	(11)
At December 31, 2010	3 019	182	166	55	3 422
Derecognition of goodwill (note 33)	**(267)**	**(8)**	**—**	**—**	**(275)**
Additions	**—**	**—**	**—**	**3**	**3**
Amortization	**—**	**—**	**—**	**(11)**	**(11)**
At December 31, 2011	**2 752**	**174**	**166**	**47**	**3 139**

The company performed its most recent goodwill impairment test at July 31, 2011. Recoverable amounts for the Oil Sands CGUs were based on fair value less costs to sell calculated using the present value of the CGUs' expected future cash flows. The

primary sources of cash flow information are derived from business plans approved by executives of the company, which were developed based on macroeconomic factors such as forward price curves for benchmark commodities, inflation rates and industry supply-demand fundamentals. When required, the projected cash flows in the business plan have been updated to reflect current market assessments of key assumptions, including long-term forecasts of commodity prices, inflation rates, foreign exchange rates and discount rates specific to the asset.

Cash flow forecasts are also based on past experience, historical trends and third-party evaluations of the company's reserves and resources to determine production profiles and volumes, operating costs, maintenance and capital expenditures. Production profiles, reserve volumes, operating costs, maintenance and capital expenditures are consistent with the estimates approved through the company's annual reserves evaluation process and determine the duration of the underlying cash flows used in the discounted cash flow test.

Future cash flow estimates are adjusted to reflect risks specific to the asset and discounted using after-tax discount rates. The discount rate is calculated based on the weighted-average cost of capital that is implicit in current market transactions for similar assets. The after-tax discount rate applied to cash flow projections was 11% at July 31, 2011 (July 31, 2010 – 11%) with a growth rate equal to the current inflation rate of 2% (July 31, 2010 – 2%). As a result of this analysis, management did not identify impairment within the Oil Sands operating segment and the associated allocated goodwill.

22. DEBT AND CREDIT FACILITIES

Debt and credit facilities are comprised of the following:

Short-Term Debt

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Commercial paper [1]	**761**	1 982	2 315
Other	**2**	2	2
Total short-term debt	**763**	1 984	2 317

(1) The commercial paper is supported by a revolving credit facility with a separate lender. The company is authorized to issue commercial paper to a maximum of $2.5 billion having a term not to exceed 365 days. The weighted-average interest rate as at December 31, 2011 was 0.4% (December 31, 2010 – 1.2%, January 1, 2010 – 0.5%).

Long-Term Debt

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Fixed-term debt, redeemable at the option of the company			
6.85% Notes, due 2039 (US$750)	**763**	746	785
6.80% Notes, due 2038 (US$900)	**942**	922	972
6.50% Notes, due 2038 (US$1150)	**1 170**	1 144	1 204
5.95% Notes, due 2035 (US$600)	**566**	552	578
5.95% Notes, due 2034 (US$500)	**509**	497	523
5.35% Notes, due 2033 (US$300)	**263**	255	266
7.15% Notes, due 2032 (US$500)	**509**	497	523
6.10% Notes, due 2018 (US$1250)	**1 271**	1 243	1 308
6.05% Notes, due 2018 (US$600)	**621**	609	643
5.00% Notes, due 2014 (US$400)	**413**	406	429
4.00% Notes, due 2013 (US$300)	**305**	298	313
7.00% Debentures, due 2028 (US$250)	**263**	257	271
7.875% Debentures, due 2026 (US$275)	**312**	307	325
9.25% Debentures, due 2021 (US$300)	**376**	375	402
5.39% Series 4 Medium Term Notes, due 2037	**600**	600	600
5.80% Series 4 Medium Term Notes, due 2018	**700**	700	700
6.70% Series 2 Medium Term Notes, due 2011 (1)	**—**	500	500
	9 583	9 908	10 342
Revolving-term debt, with variable interest rates			
Bankers' acceptances and LIBOR loans (weighted-average interest rate at January 1, 2010 – 0.9%)	**—**	—	929
Total unsecured long-term debt	**9 583**	9 908	11 271
Secured long-term debt	**13**	13	13
Finance leases (2)	**476**	477	465
Fair value adjustment related to interest rate swaps	**—**	8	18
Deferred financing costs	**(56)**	(59)	(63)
	10 016	10 347	11 704
Current portion of long-term debt			
6.70% Series 2 Medium Term Notes, due 2011 (1)	**—**	(500)	—
Finance leases (2)	**(12)**	(10)	(14)
Fair value adjustment related to interest swaps	**—**	(8)	(11)
	(12)	(518)	(25)
Total long-term debt	**10 004**	9 829	11 679

(1) The company entered into an interest rate swap transaction on $200 million of the principal amount of this note. In August 2011, the principal was repaid and the interest rate swap instruments expired. The interest rate swaps resulted in an average effective interest rate on the $200 million principal of 2.5% for the first seven months of 2011 (2010 – 1.9%).

(2) Interest rates range from 4.7% to 13.4%, and maturity dates range from 2012 to 2037.

Required Debt Repayments

Required debt repayments for finance leases, short-term debt and long-term debt are as follows:

($ millions)	Repayment
2012	775
2013	331
2014	421
2015	16
2016	17
Thereafter	9 205
Total	10 765

Credit Facilities

A summary of available and unutilized credit facilities is as follows:

($ millions)	**2011**
Fully revolving for a period of one year and expires in 2013	**2 000**
Fully revolving for a period of four years and expires in 2013	**203**
Fully revolving for a period of five years and expires in 2016	**3 000**
Can be terminated at any time at the option of the lenders	**612**
Total available credit facilities	**5 815**
Credit facilities supporting outstanding commercial paper	**(761)**
Credit facilities supporting standby letters of credit	**(626)**
Total unutilized credit facilities	**4 428**

23. OTHER LONG-TERM LIABILITIES

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Pensions and other post-retirement benefits (note 24)	**1 683**	1 275	1 143
Share-based compensation plans (note 27)	**187**	331	224
Deferred revenue	**84**	94	94
Fort Hills purchase obligation [(1)]	**275**	327	322
Libya EPSAs signature bonus [(2)]	**73**	38	280
Other	**90**	38	10
	2 392	2 103	2 073

(1) As part of the acquisition of Petro-Canada in 2009, the company assumed an obligation relating to Petro-Canada's acquisition of an additional 5% interest in the Fort Hills project in 2007 from another partner in the project. To pay for this investment the company will fund $375 million of expenditures in excess of its working interest. At December 31, 2011, the carrying amount of the Fort Hills obligation, based on the discounted estimated payout pattern for the funding, was $327 million (2010 – $327 million), of which the current portion is $52 million (2010 – $nil) and is recorded in Accounts Payable and Accrued Liabilities.

(2) The company also assumed the remaining US$500 million obligation for a signature bonus relating to Petro-Canada's ratification of six Exploration and Production Sharing Agreements (EPSAs) in Libya payable in several instalments to be paid through 2013. The company also has a US$47 million obligation related to merger consent. At December 31, 2011, the carrying amount of the total Libya obligation was $342 million (2010 – $287 million), of which the current portion is $269 million (2010 – $249 million) and is recorded in Accounts Payable and Accrued Liabilities.

24. PENSIONS AND OTHER POST-RETIREMENT BENEFITS

The company's defined benefit pension plans provide pension benefits at retirement based on years of service and final average earnings. These obligations are met through funded registered retirement plans and through unregistered supplementary pensions and senior executive retirement plans that are voluntarily funded through retirement compensation arrangements, and/or paid directly to recipients. The amount and timing of future funding for these supplementary plans is subject to capital availability and is at the company's discretion. Company contributions to the funded plans are deposited with independent trustees who act as custodians of the plans' assets, as well as the disbursing agents of the benefits to recipients. Plan assets are managed by a pension committee on behalf of beneficiaries. The committee retains independent managers and advisors.

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, depending on funding status, and every year in the United States. The most recent valuation was performed as at December 31, 2011. The company uses a measurement date of December 31 to value the plan assets and accrued benefit obligation for accounting purposes.

The company's other post-retirement benefits programs are unfunded and include certain health care and life insurance benefits provided to retired employees and eligible surviving dependants.

The company also provides a number of defined contribution plans, including a U.S. 401(k) savings plan, that provide for an annual contribution of 5% to 9% of each participating employee's pensionable earnings.

Defined Benefit Obligations and Funded Status

($ millions)	Pension Benefits 2011	Pension Benefits 2010	Other Post-Retirement Benefits 2011	Other Post-Retirement Benefits 2010
Change in benefit obligation				
Benefit obligation at beginning of year	**3 219**	2 875	**462**	401
Current service costs	**111**	87	**10**	10
Plan participants' contributions	**13**	11	**—**	—
Benefits paid	**(161)**	(151)	**(17)**	(12)
Interest costs	**165**	168	**23**	24
Foreign exchange	**(18)**	(14)	**—**	(1)
Settlements	**(6)**	—	**—**	—
Actuarial loss	**375**	243	**32**	40
Benefit obligation at end of year	**3 698**	3 219	**510**	462
Change in plan assets				
Fair value of plan assets at beginning of year	**2 335**	2 072	**—**	—
Employer contributions	**205**	188	**—**	—
Plan participants' contributions	**13**	11	**—**	—
Benefits paid	**(161)**	(151)	**—**	—
Foreign exchange	**3**	(9)	**—**	—
Settlements	**(7)**	—	**—**	—
Expected return on plan assets	**160**	142	**—**	—
Actuarial gain (loss)	**(49)**	82	**—**	—
Fair value of plan assets at end of year	**2 499**	2 335	**—**	—
Net unfunded obligation	**1 199**	884	**510**	462

The net unfunded obligation is recorded in Accounts Payable and Accrued Liabilities and Other Long-Term Liabilities in the Consolidated Balance Sheets.

($ millions)	Pension Benefits 2011	Pension Benefits 2010	Other Post-Retirement Benefits 2011	Other Post-Retirement Benefits 2010
Analysis of amount charged to earnings:				
Current service costs	**111**	87	**10**	10
Interest costs	**165**	168	**23**	24
Settlement	**1**	—	**—**	—
Expected return on plan assets	**(160)**	(142)	**—**	—
Defined benefit plans expense	**117**	113	**33**	34
Defined contribution plans expense	**43**	40	**—**	—
Total benefits plans expense charged to earnings	**160**	153	**33**	34
Analysis of amount recognized in other comprehensive income:				
Actual return less expected return on plan assets	**49**	(82)	**—**	—
Change in assumptions underlying the present value of the plan liabilities	**367**	240	**(3)**	45
Experience gains and losses arising on the plan liabilities	**8**	3	**35**	(5)
Actuarial loss recognized in other comprehensive income	**424**	161	**32**	40

Accumulated actuarial losses in retained earnings at December 31, 2011 were $657 million (December 31, 2010 – $201 million).

Actuarial Assumptions

The cost of the defined benefit pension plans and other post-retirement benefits received by employees is actuarially determined using the projected unit credit method of valuation that includes employee service to date and present pay levels, as well as projection of salaries and service to retirement.

The significant weighted-average actuarial assumptions were as follows:

(per cent)	Pension Benefits 2011	Pension Benefits 2010	Other Post-Retirement Benefits 2011	Other Post-Retirement Benefits 2010
Benefit Obligation at December 31				
Discount rate	**4.40**	5.10	**4.40**	5.25
Rate of compensation increase	**3.70**	3.70	**3.70**	4.00
Benefit Plans Expense year ended December 31				
Discount rate	**5.10**	5.85	**5.25**	6.00
Expected return on plan assets	**6.70**	6.65	**N/A**	N/A
Rate of compensation increase	**3.70**	3.90	**4.00**	4.00

The discount rate assumption is based on the interest rate on high-quality bonds with maturity terms equivalent to the benefit obligations.

The expected return on plan assets is the expected long-term rate of return on plan assets for the year and is based on plan assets at the beginning of the year that have been adjusted on a weighted-average basis for contributions and benefit payments expected for the year.

To estimate the expected long-term rate of return on plan assets, the company considered the current level of expected returns on the fixed income portion of the portfolio, the historical level of the risk premium associated with other asset classes in which the portfolio is invested and the expectation for future returns on each asset class. The expected return for each asset class was weighted based on the policy asset mix to develop an expected long-term rate of return on asset assumption for the portfolio.

In order to measure the expected cost of other post-retirement benefits, a 7% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2011 (2010 – 8%). It is assumed this rate will remain constant in 2012 and 2013 and will decrease 0.5% annually to 5% by 2017, and remain at that level thereafter.

Assumed health care cost trend rates may have a significant effect on the amounts reported for other post-retirement benefit obligations. A one per cent change in assumed health care cost trend rates would have the following effects:

($ millions)	1% increase	1% decrease
Effect on the aggregate service and interest costs	3	(2)
Effect on the benefit obligations	43	(35)

Plan Assets and Investment Objectives

The company's long-term investment objective is to secure the defined pension benefits while managing the variability and level of its contributions. The portfolio is rebalanced periodically as required, while ensuring that the maximum equity content is 65% at any time. Plan assets are restricted to those permitted by legislation, where applicable. Investments are made through pooled, mutual, segregated or exchange traded funds.

The company's weighted-average pension plan asset allocation based on market values as at December 31, 2011 and 2010, are as follows:

(per cent)	2011	2010
Equities	**55**	58
Fixed income	**45**	42
Total	**100**	100

Equity securities do not include any direct investments in Suncor shares.

The company expects to make cash contributions to its defined benefit pension plans in 2012 of $280 million.

25. PROVISIONS

($ millions)	Decommissioning and Restoration [1]	Royalties [2]	Other	Total
At January 1, 2010	3 496	421	270	4 187
Liabilities incurred	80	145	212	437
Changes in estimates	(183)	(86)	64	(205)
Liabilities settled	(417)	(110)	(136)	(663)
Accretion	186	—	15	201
Asset divestitures	(470)	—	—	(470)
Foreign exchange	(59)	—	(5)	(64)
At December 31, 2010	2 633	370	420	3 423
Less: current portion	147	370	91	608
Less: associated with assets held for sale	311	—	—	311
	2 175	—	329	2 504
At December 31, 2010	2 633	370	420	3 423
Liabilities incurred	**219**	**237**	**42**	**498**
Changes in estimates	**1 690**	**4**	**1**	**1 695**
Liabilities settled	**(496)**	**(256)**	**(63)**	**(815)**
Accretion	**140**	**—**	**6**	**146**
Asset divestitures	**(390)**	**—**	**—**	**(390)**
Foreign exchange	**5**	**—**	**1**	**6**
At December 31, 2011	**3 801**	**355**	**407**	**4 563**
Less: current portion	**372**	**355**	**84**	**811**
	3 429	**—**	**323**	**3 752**

(1) Represents decommissioning and restoration provisions associated with the retirement of property, plant and equipment. The total undiscounted amount of estimated future cash flows required to settle the obligations at December 31, 2011 was approximately $7.3 billion (December 31, 2010 – $5.5 billion). A weighted-average credit-adjusted risk-free interest rate of 4.3% was used to discount the provision recognized at December 31, 2011 (December 31, 2010 – 5.4%). The credit-adjusted risk-free rate used reflects the expected timeframe of the provisions. Payments to settle the decommissioning and restoration provisions occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed fifty years.

(2) In 2010, the Minister of Energy for Alberta provided notice to the company for the quality and transportation adjustments to be used under the Bitumen Valuation Methodology (Ministerial) Regulations for the term of the Suncor Royalty Amending Agreement that expires December 31, 2015. As a result, in 2010 the company recognized a recovery of provision amounts previously recorded in 2009 of $65 million. The company is still pursuing final settlement of the quality adjustment.

26. SHARE CAPITAL

Authorized

Common Shares

The company is authorized to issue an unlimited number of common shares without nominal or par value.

Preferred Shares

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

Normal Course Issuer Bid

In the third quarter of 2011, the company announced a Normal Course Issuer Bid (NCIB) to purchase for cancellation up to $500 million of its common shares between September 6, 2011 and September 5, 2012. During the year, the company completed the NCIB by purchasing 17.1 million common shares for total consideration of $500 million. Of the amount paid, $222 million was charged to share capital and $278 million to retained earnings.

27. SHARE-BASED COMPENSATION

(a) Stock Option Plans

Stock options that give the holder the right to purchase common shares at the grant date market price subject to fulfilling vesting terms are accounted for as equity-settled plans. Stock options that the holder can settle for cash or common shares are accounted for as cash-settled plans.

Equity-Settled Stock Option Plans

(i) Suncor Energy Inc. Stock Options

This plan replaced the pre-merger stock option plans of legacy Suncor and legacy Petro-Canada. Outstanding options that are cancelled, expire or otherwise result in no underlying common share being issued, will be available for issuance as options under this plan. Options granted have a seven-year life and vest annually over a three-year period.

(ii) Discontinued Plans

The following plans were in place prior to August 1, 2009: SunShare 2012 Performance Stock Options, Executive Stock Options, Key Contributor Stock Options, and legacy Petro-Canada Stock Options. For details of the terms and conditions of these plans, refer to the company's 2010 audited annual financial statements.

Fair values of options accounted for as equity-settled are estimated as at the grant date using the Monte-Carlo simulation approach for the SunShare 2012 plan and the Black-Scholes option-pricing model for all other plans. The weighted-average fair values of the options granted during the various periods and the weighted-average assumptions used in their determination are as noted below:

	2011	2010
Annual dividend per share	**$0.43**	$0.40
Risk-free interest rate	**2.50%**	2.02%
Expected life	**5 years**	5 years
Expected volatility	**49%**	50%
Weighted-average fair value per option	**$16.52**	$12.98

The expected life is based on historical experience and current expectations. The expected volatility reflects the assumption that the historical volatility over a period similar to the life of the options is indicative of future trends.

Cash-Settled Stock Option Plans

(i) Suncor Energy Inc. Stock Options with TSARs

Options were granted under this plan between August 1, 2009 and July 31, 2010. Each option included a tandem stock appreciation right (TSAR). Options granted have a seven-year life and vest annually over a three-year period.

(ii) Legacy Petro-Canada Stock Options with CPAs

This plan was discontinued on August 1, 2009. Options were granted to executives and key employees, and can be settled in common shares or exchanged for a cash payment alternative (CPA). Options granted have a seven-year life and vest over periods of up to four years.

Fair values of options accounted for as cash-settled are estimated as at the reporting date using the Black-Scholes option-pricing model. The expected life assumption is based on historical data and current expectations. The expected volatility reflects the assumption that the historical volatility over a period similar to the life of the options is indicative of future trends.

Changes in the total outstanding stock options were as follows:

	2011		2010	
	Number (thousands)	**Weighted-Average Exercise Price ($)**	Number (thousands)	Weighted-Average Exercise Price ($)
Outstanding, beginning of year	**67 638**	**32.94**	72 024	32.52
Granted	**5 840**	**41.08**	4 297	31.86
Exercised	**(9 918)**	**20.93**	(5 292)	15.49
Forfeited/expired	**(4 382)**	**40.51**	(3 391)	42.51
Outstanding, end of year	**59 178**	**35.25**	67 638	32.94
Exercisable, end of year	**39 482**	**32.03**	46 266	29.91

Options are exercised regularly throughout the year. Therefore, the weighted-average share price during the year of $36.18 (2010 – $33.73) is representative of the weighted-average share price at the date of exercise.

For the options outstanding at December 31, 2011, the exercise price ranges and weighted-average remaining contractual lives are shown below:

	Outstanding	
Exercise Prices ($)	Number (thousands)	Weighted-Average Remaining Contractual Life (years)
11.96-14.99	7 346	1
15.00-29.99	10 503	3
30.00-45.99	23 636	4
46.00-49.99	16 575	3
50.00-69.97	1 118	3
Total	59 178	3

Common shares authorized for issuance by the Board of Directors that remain available for the granting of future options:

(thousands)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
	10 347	12 785	16 196

(b) Stock Appreciation Rights (SARs)

A SAR entitles the holder to receive a cash payment equal to the difference between the stated exercise price and the market price of the company's common shares on the date the SAR is exercised, and is accounted for as a cash-settled plan.

(i) Suncor Energy Inc. SARs

These SARs have a seven-year life and vest annually over a three-year period.

(ii) Legacy Petro-Canada SARs

This plan was discontinued on August 1, 2009. These SARs have a seven-year life and vest annually over a four-year period.

Fair values of SARs are estimated under the same methodology used for cash-settled stock options. Changes in the number of outstanding SARs were as follows:

	2011		2010	
	Number (thousands)	**Weighted-Average Exercise Price ($)**	Number (thousands)	Weighted-Average Exercise Price ($)
Outstanding, beginning of year	**11 285**	**28.97**	14 065	28.63
Granted	**197**	**41.26**	353	31.85
Exercised	**(2 003)**	**29.54**	(734)	24.00
Forfeited/expired	**(727)**	**28.10**	(2 399)	28.99
Outstanding, end of year	**8 752**	**29.32**	11 285	28.97
Exercisable, end of year	**5 625**	**31.49**	4 939	32.28

(c) Share Unit Plans

The company's share unit plans are accounted for as cash-settled plans.

A performance share unit (PSU) is a time-vested award entitling employees to receive varying degrees of cash (0% – 200% of the company's share price at time of vesting) contingent upon Suncor's total shareholder return (stock price appreciation and dividend income) relative to a peer group of companies. PSUs vest approximately three years after the grant date.

A restricted share unit (RSU) is a time-vested award entitling employees to receive cash equal to the company's share price at the time of vesting. Typically, RSUs vest approximately three years after the grant date.

A deferred share unit (DSU) is redeemable for cash or a common share for a period of time after a unitholder ceases employment or Board membership. The DSU plan is limited to executives and members of the Board of Directors. Members of the Board of Directors receive one-half or, at their option, all of their compensation in the form of DSUs. Executives may elect to receive one-half, or all, of their annual incentive payment in the form of DSUs.

Changes in the number of outstanding share units were as follows:

(thousands)	PSU	RSU	DSU
Outstanding, January 1, 2010	3 247	4 250	2 616
Granted	1 699	2 881	109
Redeemed for cash	(282)	(118)	(426)
Forfeited/expired	(917)	(563)	—
Outstanding, December 31, 2010	3 747	6 450	2 299
Granted	**2 050**	**4 237**	**152**
Redeemed for cash	**(224)**	**(840)**	**(749)**
Forfeited/expired	**(913)**	**(553)**	**—**
Outstanding, December 31, 2011	**4 660**	**9 294**	**1 702**

Fair values are estimated as at the reporting date using the Monte-Carlo simulation approach for PSUs and the Black-Scholes option-pricing model for other share unit plans. The expected volatility reflects the assumption that the historical volatility over a period similar to the life of the share units is indicative of future trends.

Share-Based Compensation Expense (Recovery)

The following table summarizes the share-based compensation expense (recovery) recorded for all plans within Operating, Selling and General expense in the Consolidated Statements of Comprehensive Income.

($ millions)	**2011**	2010
Equity-settled plans	**94**	4
Cash-settled plans	**(95)**	190
Total share-based compensation expense (recovery)	**(1)**	194

Liability Recognized for Share-Based Compensation

The company has recorded a liability of $405 million as at December 31, 2011 (2010 – $666 million), of which $218 million was classified as current (2010 – $335 million), based on the fair value of awards accounted for as cash-settled. The intrinsic value of the vested awards at December 31, 2011 was $161 million (2010 – $225 million).

28. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The company's financial instruments consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all accounts payable and accrued liabilities, debt, and portions of other assets and other long-term liabilities.

Non-Derivative Financial Instruments

The fair values of cash and cash equivalents, accounts receivable, short-term debt, and accounts payable and accrued liabilities approximate their carrying values due to the short-term maturities of those instruments.

The fair value of the company's financial instrument included in other assets was calculated using a discounted cash flow model. The inputs used in the model were based on observable market data, where available.

The company's long-term debt and long-term financial liabilities are recorded at amortized cost using the effective interest method, except for a portion of debt that was recorded at fair value as part of a fair value hedging relationship until August 2011 (see note 22). At December 31, 2011, the carrying value of fixed-term debt accounted for under amortized cost was $9.6 billion (December 31, 2010 – $9.7 billion) and the fair value at December 31, 2011 was $11.4 billion (December 31, 2010 – $10.7 billion).

Derivative Financial Instruments

(a) Fair Value Hierarchy

To estimate fair value of derivatives, the company uses quoted market prices when available, or third-party models and valuation methodologies that utilize observable market data. In addition to market information, the company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a

current market transaction. The company characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

- Level 1 – inputs represent quoted prices in active markets for identical assets or liabilities. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – inputs other than quoted prices that are observable, either directly or indirectly, as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, market interest rates, and volatility factors, which can be observed or corroborated in the marketplace.
- Level 3 – inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value.

In forming estimates, the company utilizes the most observable inputs available for valuation purposes. If a fair value measurement reflects inputs of different levels within the hierarchy, the measurement is categorized based upon the lowest level of input that is significant to the fair value measurement.

The following table presents the company's derivative financial instrument assets and liabilities measured at fair value for each hierarchy level as at December 31, 2011:

($ millions)	Level 1	Level 2	Level 3	Total Fair Value
Accounts receivable	11	3	13	27
Accounts payable	(72)	(14)	(7)	(93)
Balance at December 31, 2010	(61)	(11)	6	(66)
Accounts receivable	**1**	**33**	**3**	**37**
Accounts payable	**(18)**	**(51)**	**(2)**	**(71)**
Balance at December 31, 2011	**(17)**	**(18)**	**1**	**(34)**

(b) Designated as Part of a Qualifying Hedge Relationship

The company periodically enters into derivative financial instrument contracts such as interest rate swaps as part of its risk management strategy to manage its exposure to benchmark interest rate fluctuations. During 2011, the company held interest rate swaps designated as fair value hedges on $200 million of fixed-term debt. These swaps expired in August 2011. The fair value of these swaps as at December 31, 2010 was $8 million.

(c) Non-Designated Derivative Financial Instruments

Risk Management Derivatives

The company periodically enters into derivative contracts which although not accounted for as hedges because they have not been documented as such, or do not qualify under GAAP, are believed to be economically effective at managing exposure to commodity price movements and are a component of Suncor's overall risk management program.

Gains or losses associated with risk management derivatives are reported in the related operating segment as part of Other Income. The earnings impact associated with these contracts for the year ended December 31, 2011 was a loss of $22 million (2010 – gain of $89 million).

Energy Trading Derivatives

The company's Energy Trading group also uses physical and financial energy contracts, including swaps, forwards and options to earn trading revenues.

Gains or losses from trading activities are reported in Other Income as part of Corporate, Energy Trading and Eliminations. The earnings impact for the year ended December 31, 2011 was a gain of $301 million (2010 – gain of $106 million).

Change in Fair Value of Non-Designated Derivative Financial Instruments

($ millions)	Risk Management	Energy Trading	Total
Fair value of contracts outstanding at January 1, 2010	(312)	(47)	(359)
Fair value of contracts realized during the period	236	(146)	90
Changes in fair value during the period	89	106	195
Fair value of contracts outstanding at December 31, 2010	13	(87)	(74)
Fair value of contracts realized during the period	**9**	**(248)**	**(239)**
Changes in fair value during the period	**(22)**	**301**	**279**
Fair value of contracts outstanding at December 31, 2011	**—**	**(34)**	**(34)**

Risk Management

The company is exposed to a number of different risks arising from financial instruments. These risk factors include market risks, comprising commodity price risk, foreign currency risk and interest rate risk, as well as liquidity risk and credit risk.

The company maintains a formal governance process to manage its financial risks. The company's Commodity Risk Management Committee (CRMC) is charged with the oversight of the company's trading and credit risk management activities. Trading activities are defined as strategic hedging, optimization trading, marketing and trading. The CRMC, acting under the authority of the company's Board of Directors, meets regularly to monitor limits on risk exposures, review policy compliance and validate risk-related methodologies and procedures.

The nature of the risks faced by the company and its policies for managing such risks remains unchanged from December 31, 2010.

1) Market Risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of the business. The market price movements that could adversely affect the value of the company's financial assets, liabilities and expected future cash flows include commodity price risk, foreign currency exchange risk and interest rate risk.

(a) Commodity Price Risk

Suncor's financial performance is closely linked to crude oil prices (including pricing differentials for various product types), and to a lesser extent, natural gas and refined product prices. The company may reduce its exposure to commodity price risk through a number of strategies. These strategies include committing a portion of expected crude oil production to fixed price contracts, entering into option contracts to limit exposure to changes in crude oil prices and hedging natural gas exposures to manage regional price differentials.

Changes in crude oil and natural gas prices would have the following impact on pre-tax earnings for the company's outstanding derivative financial instruments at December 31, 2011 and 2010:

($ millions)	2011 [1]	Change	Pre-tax Earnings
Crude Oil	US$96.12/barrel		
Price increase		US$1.00/barrel	(8)
Price decrease		US$1.00/barrel	8
Natural Gas	US$3.56/mcf		
Price increase		US$0.10/mcf	(1)
Price decrease		US$0.10/mcf	1

($ millions)	2010 [1]	Change	Pre-tax Earnings
Crude Oil	US$93.37/barrel		
Price increase		US$1.00/barrel	(4)
Price decrease		US$1.00/barrel	4
Natural Gas	US$4.99/mcf		
Price increase		US$0.10/mcf	(4)
Price decrease		US$0.10/mcf	4

(1) Prices represent the average of futures' prices at December 31, 2011 and 2010, respectively.

(b) Foreign Currency Exchange Risk

The company is exposed to foreign currency exchange risk on revenues, capital expenditures, or financial instruments that are denominated in a currency other than the company's functional currency (Canadian dollars). As crude oil is priced in U.S. dollars, fluctuations in US$/Cdn$ exchange rates may have a significant impact on revenues. This exposure is partially offset through the issuance of U.S. dollar denominated long-term debt and by sourcing capital projects in U.S. dollars. A 1% change in the US$/Cdn$ exchange rate at December 31, 2011 would change pre-tax earnings by approximately $88 million (2010 – $90 million).

The company also has foreign operations whose functional currency is different than the company's functional currency. The main exposures relate to foreign operations whose functional currencies are in U.S. dollars or Euros (€). A 1% change in the US$/Cdn$ exchange rate and €/Cdn$ exchange rate at December 31, 2011 would impact other comprehensive income by approximately $45 million and $23 million, respectively (2010 – $37 million and $23 million, respectively).

(c) Interest Rate Risk

The company is exposed to interest rate risk as changes in interest rates may affect future cash flows and the fair values of its financial instruments. The primary exposure is related to its revolving-term debt (commercial paper, bankers' acceptances and LIBOR loans).

To manage the company's position with respect to interest expense, the company targets 30% to 50% of total debt to be exposed to floating interest rates. Over time, this floating/fixed rate mix will fluctuate based on prevailing market conditions and management's assessment of overall risk. The proportion of floating interest rate exposure at December 31, 2011 was 7% of total debt outstanding (2010 – 18%). The weighted-average interest rate on total debt for the year ending December 31, 2011 was 6.0% (2010 – 5.7%).

The company's net earnings are sensitive to changes in interest rates on the floating rate portion of the company's debt. To the extent interest expense is not capitalized, if interest rates applicable to floating rate instruments increased by 1%, it is estimated that the company's pre-tax earnings would decrease by approximately $8 million (2010 – $22 million). This assumes that the amount and mix of fixed and floating rate debt remains unchanged from December 31, 2011, and that the change in interest rates is effective from the beginning of the year.

2) Liquidity Risk

Liquidity risk is the risk that Suncor will not be able to meet its financial obligations when due. The company mitigates this risk by forecasting spending requirements and maintaining sufficient cash and credit facilities to meet these requirements. Suncor's cash and cash equivalents and available credit facilities at December 31, 2011 were $3.8 billion and $5.8 billion, respectively.

Surplus cash is invested into a range of short-dated money market securities. Investments are only permitted in high credit quality government or corporate securities. Diversification of these investments is maintained through counterparty credit limits.

The following table shows the timing of cash outflows related to trade and other payables and debt.

	December 31, 2011		December 31, 2010	
($ millions)	**Trade and other payables [1]**	**Debt [2]**	Trade and other payables [1]	Debt [2]
Within one year	**7 755**	**1 411**	6 524	3 128
1 to 3 years	**274**	**2 012**	359	1 562
3 to 5 years	**52**	**1 238**	32	1 615
Over 5 years	**—**	**17 259**	—	17 473
Total	**8 081**	**21 920**	6 915	23 778

(1) Includes the Fort Hills purchase obligation and the Libya EPSAs signature bonus.

(2) Debt includes short-term debt, long-term debt, finance leases and interest payments on fixed-term debt and commercial paper.

3) Credit Risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss. The company's credit policy is designed to ensure there is a standard credit practice throughout the company to measure and monitor credit risk. The policy outlines delegation of authority, the due diligence process required to approve a new customer or counterparty and the maximum amount of credit exposure per single entity. Before transactions begin with a new customer or counterparty, its creditworthiness is assessed, a credit rating is assigned and a maximum credit limit is allocated. The assessment process is outlined in the credit policy and considers both quantitative and qualitative factors. The company

constantly monitors the exposure to any single customer or counterparty along with the financial position of the customer or counterparty. If it is deemed that a customer or counterparty has become materially weaker, the company will work to reduce the credit exposure and lower the credit limit allocated. Regular reports are generated to monitor credit risk and the Credit Committee meets quarterly to ensure compliance with the credit policy and review the exposures.

A substantial portion of the company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risk. At December 31, 2011 and 2010, substantially all of the company's trade receivables were current. However, as a result of political unrest in Syria, the company has not received payment for recent production from its Syrian operations. The company has recorded a provision of $63 million against these receivables, which represents approximately half of the overall balance outstanding.

The company may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts with positive fair values at the reporting date. At December 31, 2011, the company's exposure was $37 million (December 31, 2010 – $27 million).

29. CAPITAL STRUCTURE FINANCIAL POLICIES

The company's primary capital management objective is to maintain a conservative balance sheet, which supports a solid investment-grade credit rating profile. This objective affords the company the financial flexibility and access to the capital it requires to execute on its growth objectives.

The company's capital is monitored through net debt to cash flow from operations (1) and total debt to total debt plus shareholders' equity.

Net debt to cash flow from operations is calculated as short-term debt plus total long-term debt less cash and cash equivalents divided by cash flow from operations for the year then ended.

Total debt to total debt plus shareholders' equity is calculated as short-term debt plus total long-term debt divided by short-term debt plus total long-term debt plus shareholders' equity.

Financial covenants associated with the company's various banking and debt agreements are reviewed regularly and controls are in place to maintain compliance with these covenants. The company complied with all financial covenants for the years ended December 31, 2011 and 2010.

The company's strategy during 2011, which was unchanged from 2010, was to maintain the measure set out in the following schedule. The company believes that achieving this capital target helps to provide the company access to capital at a reasonable cost by maintaining solid investment-grade credit ratings. The company operates in a cyclical business environment and ratios may periodically fall outside of management's targets.

At December 31 ($ millions)	Capital Measure Target	**2011**	2010
Components of ratios			
Short-term debt		**763**	1 984
Current portion of long-term debt		**12**	518
Long-term debt		**10 004**	9 829
Total debt		**10 779**	12 331
Less: Cash and cash equivalents		**3 803**	1 077
Net debt		**6 976**	11 254
Shareholders' equity		**38 600**	35 192
Total capitalization (total debt plus shareholders' equity)		**49 379**	47 523
Cash flow from operations (1)		**9 746**	6 656
Net debt to cash from operations	<2.0 times	**0.7**	1.7
Total debt to total debt plus shareholders' equity		**22%**	26%

(1) Cash flow from operations is expressed before changes in non-cash working capital.

30. INTERESTS IN JOINT VENTURES

Significant jointly controlled entities at December 31, 2011 are set out below:

	%
Fort Hills Energy L.P. [1]	40.8
Syncrude Canada Ltd. [2]	12.0
Voyageur Upgrader L.P. [3]	51.0
Magrath Windfarm Joint Venture	33.3
Chin Chute Windfarm Joint Venture	33.3
Ripley Windfarm Joint Venture	50.0
Wintering Hills Joint Venture	70.0
Chimies Parachem S.E.C. / Parachem Chemicals L.P.	51.0
UPI Inc.	50.0

(1) The company's share of Fort Hills Energy L.P. was 60.0% at January 1, 2010 and December 31, 2010.

(2) Syncrude Canada Ltd. is the operator of the Syncrude oil sands joint venture, a jointly controlled asset. Syncrude Canada Ltd. is responsible for the management and administration of this asset.

(3) Voyageur Upgrader L.P. was a wholly-owned subsidiary at January 1, 2010 and December 31, 2010.

Summarized financial information for the company's share of its jointly controlled entities is shown below:

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Current assets	**127**	128	101
Non-current assets	**2 935**	1 227	1 246
	3 062	1 355	1 347
Current liabilities	**135**	183	148
Non-current liabilities	**146**	64	110
	281	247	258
Revenues and other income	**541**	672	
Expenses	**746**	852	
Net earnings	**(205)**	(180)	

31. RELATED PARTY DISCLOSURES

Related Party Transactions

The company enters into transactions with related parties in the normal course of business. These are primarily sales to associated entities in the company's refining and marketing operations. Operating revenues after eliminations for these transactions were $780 million for the year ended December 31, 2011 (2010 – $730 million). At December 31, 2011, amounts due from related parties were $60 million (2010 – $60 million).

Compensation of Key Management Personnel

Compensation of the company's Board of Directors and members of the Executive Leadership Team for the years ended December 31 is as follows:

($ millions)	**2011**	2010
Short-term benefits	**17**	13
Pension and other post-retirement benefits	**3**	3
Share-based compensation	**29**	38
	49	54

32. COMMITMENTS, CONTINGENCIES AND GUARANTEES

(a) Operating Commitments

Future payments under the company's operating leases for pipeline transportation agreements and for various premises, service stations and other property and equipment are as follows:

($ millions)	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
Within one year	**1 080**	1 126	1 077
After one year but not more than five years	**3 768**	3 409	3 281
More than five years	**8 785**	8 386	8 019
	13 633	12 921	12 377

Significant operating leases expire at various dates through 2028. For the year ended December 31, 2011, operating lease expense was $1.1 billion (2010 – $1.0 billion).

Suncor also has commodity purchase arrangements which are transacted at market prices and in the normal course of business, which may terminate on short notice.

(b) Contingencies

The company reduces exposure to some operational risks by maintaining a comprehensive insurance program at limits and deductible amounts that management believes to be acceptable.

The company carries property damage and business interruption insurance with varying coverage limits and deductible amounts based on the asset. As of December 31, 2011, Suncor's insurance program includes a coverage limit of up to US$1.3 billion for oil sands risks, up to US$1.25 billion for offshore risks and up to US$600 million for refining risks. These limits are all net of deductible amounts or waiting periods and subject to certain price and volume limits. The company also has primary property insurance for US$250 million that covers all of Suncor's assets. As part of its normal course of operations, Suncor carries risk mitigation instruments in the aggregate amount of $405 million on certain foreign operations, of which up to $300 million can apply to our assets in Syria.

Suncor believes its liability, property and business interruption insurance is appropriate to its business, although such insurance will not provide coverage in all circumstances or fully protect against prolonged outages. In the future, the insurance program may change due to market conditions or other business considerations.

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and to be funded from the company's cash flow from operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, the impact may be material.

(c) Guarantees

At December 31, 2011, the company had various indemnification agreements with third parties as described below and provides loan guarantees to certain retail licensees.

The company has agreed to indemnify holders of all notes and debentures and the company's credit facility lenders (see note 22) for added costs relating to withholding taxes. Similar indemnity terms apply to certain facility and equipment leases.

There is no limit to the maximum amount payable under the indemnification agreements described above. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, the company has the option to redeem or terminate these contracts if additional costs are incurred.

33. JOINT VENTURE WITH TOTAL

In March 2011, Suncor closed the previously announced transaction to enter into a joint venture with Total E&P Canada Ltd. (Total). The two companies plan to develop the Fort Hills and Joslyn oil sands mining projects together with the other project partners, and restart the construction of the Voyageur upgrader.

As a result of this transaction, Suncor acquired a 36.75% interest in Joslyn for consideration of $842 million after closing adjustments. Total acquired a 49% interest in Voyageur, a 19.2% increase in its interest in Fort Hills (reducing Suncor's interest from 60% to 40.8%), and rights to proprietary mining technology, for cash consideration of $2.662 billion after closing adjustments.

Overall, Suncor recognized a loss of $124 million, after final closing adjustments, related to the disposition of its interests in Voyageur and Fort Hills and the technology sale. The loss included the derecognition of $267 million of goodwill associated with the disposed interests in Fort Hills and Voyageur.

34. SUBSEQUENT EVENT

On February 23, 2012, the company announced that it would recommence its Normal Course Issuer Bid (NCIB), and may purchase for cancellation an additional $1 billion of its common shares between February 28, 2012 and September 5, 2012.

QuickLinks

EXHIBIT 99-1

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2011

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-2

**Management's Discussion and Analysis for the fiscal year ended December 31, 2011,
dated February 23, 2012**

MANAGEMENT'S DISCUSSION AND ANALYSIS

February 23, 2012

This Management's Discussion and Analysis (MD&A) should be read in conjunction with Suncor's December 31, 2011 audited Consolidated Financial Statements and the accompanying notes. Additional information about Suncor filed with Canadian securities regulatory authorities and the United States Securities and Exchange Commission (SEC), including quarterly and annual reports and the Annual Information Form dated March 1, 2012 (the 2011 AIF), which is also filed with the SEC under cover of Form 40-F, is available online at www.sedar.com, www.sec.gov and our website www.suncor.com. Information contained in or otherwise accessible through our website does not form a part of this MD&A, and is not incorporated into this MD&A by reference.

References to "we", "our", "Suncor", or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint venture investments, unless the context requires otherwise.

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1. ADVISORIES

Basis of Presentation

Unless otherwise noted, all financial information has been prepared in accordance with Canadian generally accepted accounting principles (GAAP), which are within the framework of International Financial Reporting Standards (IFRS). Effective January 1, 2011, the company's audited Consolidated Financial Statements have been prepared in accordance with IFRS, and IFRS 1 *First-Time Adoption of International Financial Reporting Standards* (IFRS 1) has been applied. In previous years, the company prepared its financial statements in accordance with Canadian generally accepted accounting principles in effect prior to January 1, 2011 (Previous GAAP). Comparative figures presented in this MD&A pertaining to Suncor's 2010 results have been restated to be in accordance with IFRS. The impacts of the transition to IFRS on the company's previously reported financial statements for the year ended December 31, 2010, and the opening balance sheet at January 1, 2010, are presented in the notes to the audited Consolidated Financial Statements.

Comparative figures for earnings and cash flows presented in this MD&A pertaining to Suncor's 2009 results were prepared in accordance with Previous GAAP and were not required by IFRS 1 or by the Canadian Securities Administrators to be restated in accordance with IFRS. Users of this information are cautioned that 2009 results may not be directly comparable with those for 2010 and 2011 and are advised to review the First-Time Adoption of IFRS note to the audited Consolidated Financial Statements.

All financial information is reported in Canadian dollars, unless otherwise noted. Certain amounts in prior years have been reclassified to conform to the current year's presentation. Production volumes are presented on a working-interest basis, before royalties, unless otherwise noted.

Non-GAAP Financial Measures

Certain financial measures in this MD&A – namely operating earnings, cash flow from operations, return on capital employed (ROCE) and Oil Sands cash operating costs – are not prescribed by GAAP. Operating earnings are defined in the Non-GAAP Financial Measures Advisory section of this MD&A and reconciled to GAAP net earnings in the Consolidated Financial Information and Segment Results and Analysis sections of this MD&A. Cash flow from operations, ROCE and Oil Sands cash operating costs are defined and reconciled in the Non-GAAP Financial Measures Advisory section of this MD&A. The company has restated operating earnings from 2010 for the transition to IFRS and operating earnings from 2007 to 2010 for the removal of certain prior period operating earnings adjustments.

These non-GAAP financial measures do not have any standardized meaning and, therefore, are unlikely to be comparable to similar measures presented by other companies. These non-GAAP financial measures are included because management uses the information to analyze operating performance, leverage and liquidity, and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Common Abbreviations

The following is a list of abbreviations that may be used in this MD&A:

Measurement

bbl	barrel
bbls/d	barrels per day
mbbls/d	thousands of barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mcf	thousands of cubic feet of natural gas
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
mmcfe	millions of cubic feet of natural gas equivalent
mmcfe/d	millions of cubic feet of natural gas equivalent per day
m^3	cubic metres
m^3/d	cubic metres per day
MW	megawatts

Places and Currencies

U.S.	United States
U.K.	United Kingdom
$ or Cdn$	Canadian dollars
US$	United States dollars
£	Pounds sterling
€	Euros

Financial and Business Environment

DD&A	Depreciation, depletion and amortization
WTI	West Texas Intermediate
WCS	Western Canadian Select
SCO	Synthetic crude oil

Other Advisories

This MD&A contains forward-looking information based on Suncor's current expectations, estimates, projections and assumptions. This information is subject to a number of risks and uncertainties, including those discussed in this MD&A and Suncor's other disclosure documents, many of which are beyond the company's control. Users of this information are cautioned that actual results may differ materially. Refer to the Advisory – Forward-Looking Information section of this MD&A for information on the material risk factors and assumptions underlying our forward-looking information.

On August 1, 2009, Suncor completed its merger with Petro-Canada, referred to in this MD&A as the "merger". Amounts disclosed in this MD&A for 2009 reflect the results of post-merger Suncor from August 1, 2009 together with the results of pre-merger Suncor only from January 1, 2009 through July 31, 2009, unless otherwise noted.

Certain crude oil and natural gas liquids volumes have been converted to mcfe or mmcfe on the basis of one bbl to six mcf. Also, certain natural gas volumes have been converted to boe or mboe on the same basis. Any figure presented in mcfe, mmcfe, boe or mboe may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or natural gas liquids to six mcf 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. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

2. 2011 HIGHLIGHTS

- **Record operating earnings and cash flow from operations.**

  - Net earnings for 2011 were $4.304 billion, compared to $3.829 billion in 2010.
  - Operating earnings [(1)] for 2011 were a record $5.674 billion, compared to $2.634 billion in 2010.
  - Cash flow from operations [(1)] for 2011 was a record $9.746 billion, compared to $6.656 billion in 2010.

  These record financial results were due primarily to higher average upstream price realizations and downstream refining margins, and increased production from Oil Sands.

  - ROCE [(1)] (excluding major projects in progress) was 13.8% for the twelve months ended December 31, 2011, compared to 11.4% for the twelve months ended December 31, 2010. ROCE continues to improve and is at its highest level since the merger with Petro-Canada.

- **Balance sheet strength.**

  The company has a strong balance sheet with reduced net debt, due to significant cash flow from its integrated operations and proceeds from asset dispositions.

  - Net debt at December 31, 2011 was $7.0 billion, and has decreased from $11.3 billion at December 31, 2010.
  - Cash and cash equivalents at December 31, 2011 was $3.8 billion and has increased from $1.1 billion at December 31, 2010.

  Cash flow from operations exceeded 2011 capital and exploration expenditures (including capitalized interest) by $2.9 billion. Combined with proceeds from transactions with Total E&P Canada Ltd. (Total E&P) and other asset divestitures, Suncor cash balances increased significantly during the year. Suncor maintained its strong cash position throughout 2011, while increasing capital expenditures, repaying debt, completing a share repurchase program and increasing its dividend.

  During 2011:

  - The company spent $6.850 billion on capital and exploration expenditures, compared to $6.010 billion in 2010.
  - The company repaid $500 million of long-term debt and over $1.2 billion of short-term debt.
  - The company repurchased 17.1 million shares, returning $500 million to shareholders.
  - Starting in the second quarter of 2011, the company increased its quarterly dividend by 10% to $0.11 per common share.

- **Leadership transition – Suncor's long-standing CEO to retire.**

  In early December, Rick George, Suncor's chief executive officer (CEO), announced his plan to retire after more than 20 years at the helm. Steve Williams, Suncor's chief operating officer, was appointed as president and a member of the company's Board of Directors, and will assume the role of CEO upon Mr. George's retirement in May 2012.

- **Record production from Oil Sands reflected improved reliability through operational excellence.**

  Oil Sands production averaged a record 304,700 bbls/d in 2011. Production reflected improved reliability and increased bitumen feedstock from mining and In Situ operations. Oil Sands production averaged 345,000 bbls/d in December, another record. Production results for 2011 included the impacts of the largest planned maintenance event in the company's history, which was completed safely and on schedule.

- **In Situ production exits 2011 at 111,000 bbls/d.**

  Concurrent with the ramp up of production from the first well pad at the Firebag Stage 3 expansion and infill wells brought on-stream at existing well pads throughout the second half of 2011, In Situ bitumen production surpassed 100,000 bbls/d in late October, and exited 2011 at approximately 111,000 bbls/d.

  The ramp up of bitumen production from the Firebag Stage 3 expansion is expected to continue in 2012.

- **Progress on major growth projects.**

  Construction activity for the Firebag Stage 3 expansion is complete, while construction activity for the Firebag Stage 4 expansion is well underway. The company expects to begin production from the Stage 4 expansion late in the first quarter of 2013.

  The company started mining ore from the North Steepbank Extension (NSE) in late December. The hydrogen plant for the Millennium Naphtha Unit (MNU) produced hydrogen in December, before being taken off-line for minor modifications prior to further

commissioning. The start-up of the naphtha hydrotreater for the MNU is expected in 2012.

- **Transactions with Total E&P and the creation of Oil Sands Ventures.**

  After receiving the necessary regulatory approvals, in the first quarter of 2011, Suncor and Total E&P completed the transactions they had previously announced in December 2010. In exchange for net proceeds of $1.820 billion and a 36.75% interest in the Joslyn oil sands mining project, Suncor sold to Total E&P a 49% interest in the Voyageur upgrader and a 19.2% interest in the Fort Hills oil sands mining project.

  In order to manage and develop these new jointly owned assets, Suncor created a new business area – Oil Sands Ventures. Throughout 2011, Oil Sands Ventures focused on ensuring the successful restart of the Fort Hills mining and Voyageur upgrader projects, and building organizational expertise and capacity to effectively manage these projects as well as Suncor's interests in Syncrude and the Joslyn mining project.

- **Suncor's integrated business model reaps the rewards of a strong refining environment.**

  The Refining and Marketing segment contributed over $2.5 billion to cash flow from operations in 2011. Throughout much of the year, North American refining margins were very strong, particularly for inland refineries – such as Suncor's Edmonton, Sarnia and Commerce City refineries – due to a wider discount for WTI crude, compared to Brent crude. Despite major planned maintenance events in 2011 at each of these inland refineries, overall refining utilization averaged 92% for 2011, reflecting the company's focus on reliable operations.

- **Unrest in Libya and Syria.**

  In Libya, for much of the year, production was shut-in and all operations and exploration activities were suspended due to political unrest that led to international sanctions and Suncor declaring force majeure under its contractual obligations. The transition to a new government in Libya later in 2011 resulted in the lifting of sanctions impacting Suncor's operations in Libya. Production from all major fields was successfully restarted by the joint venture operator in late 2011 and early 2012. Suncor is optimistic about a gradual return to full operations in the country.

  In Syria, amid continuing unrest, sanctions were introduced that resulted in Suncor declaring force majeure under its contractual obligations and suspending its operations in the country. The company has ceased recording all production and revenue from its Syrian assets. The company continues to comply with all relevant sanctions.

- **Non-core asset divestiture activity winds down.**

  During the year, the company completed dispositions of non-core assets in the U.K. portion of the North Sea and Western Canada for total net proceeds of $304 million. Due to market conditions confronting the company's North America Onshore operations, opportunities to divest additional natural gas properties that met the company's financial objectives were limited.

- **Suncor continues investment in renewable energy assets.**

  Suncor completed the expansion of its ethanol plant in Ontario that doubled production capacity to 400 million litres per year and confirmed the plant as Canada's largest biofuels production facility. Suncor also commenced operations at two new wind power projects – the 88-MW Wintering Hills project in southern Alberta and the 20-MW Kent Breeze project in southwest Ontario.

- **Systems integration project completed.**

  The company completed the integration of assets acquired in the merger with Petro-Canada onto a common information systems platform.

- **Energy Trading optimizes price realizations for Oil Sands barrels.**

  Suncor's Energy Trading business contributed significantly to cash flow from operations in 2011. This business supports Oil Sands production by optimizing price realizations and managing inventory levels. In recent years, the Energy Trading business has entered into arrangements for midstream infrastructure, such as pipeline and storage capacity, which enables Suncor to optimize the delivery of existing and future growth production.

(1) Operating earnings, cash flow from operations and ROCE are non-GAAP financial measures. The company has restated operating earnings from 2010 for the transition to IFRS and for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

3. SUNCOR OVERVIEW

Suncor is an integrated energy company headquartered in Calgary, Alberta. Suncor has classified its operations into the following segments:

OIL SANDS

Suncor's Oil Sands segment, with assets located in northeast Alberta, recovers bitumen from mining and in situ operations and upgrades the majority of this production into refinery feedstock, diesel fuel and byproducts. The Oil Sands segment includes:

- **Oil Sands** operations refers to Suncor's wholly owned and operated mining, extraction, upgrading and in situ assets in the Athabasca oil sands region. Oil Sands activities consist of:

    - **Oil Sands Base** operations include the Millennium and Steepbank (including the NSE) mining and extraction operations, two integrated upgrading facilities known as Upgrader 1 and Upgrader 2, and the associated infrastructure for these assets – including utilities, energy and reclamation facilities, such as Tailings Reduction Operations (TRO_{TM}) assets.

    - **In Situ** operations include oil sands bitumen production from Firebag and MacKay River, and supporting infrastructure, such as central processing facilities and cogeneration units. The majority of In Situ production is upgraded by Oil Sands Base; however, the company's marketing plan includes sales of bitumen when marketing conditions are favourable or as operating conditions at Oil Sands Base require.

- **Oil Sands Ventures** includes the company's interests in significant growth projects, including two where Suncor is the operator – the Fort Hills mining project (40.8%) and the Voyageur upgrader project (51%) – and one where Total E&P is the operator – the Joslyn mining project (36.75%). Oil Sands Ventures also includes the company's 12% interest in the Syncrude oil sands mining and upgrading joint venture.

EXPLORATION AND PRODUCTION

In January 2011, Suncor combined its International and Offshore and Natural Gas segments into the Exploration and Production segment, which consists of offshore operations off the east coast of Canada and in the North Sea, and onshore operations in North America, Libya and Syria.

- **East Coast Canada** operations include Suncor's 37.675% working interest in Terra Nova, for which Suncor is the operator. Suncor also holds a 20% interest in the Hibernia base project and a 19.5% interest in the Hibernia Southern Extension Unit (HSEU), a 27.5% interest in the White Rose base project and a 26.125% interest in the White Rose Extensions, and a 22.729% interest in Hebron, all of which are operated by other companies.

- **International** operations include Suncor's 29.89% working interest in Buzzard and a 26.69% interest in the Golden Eagle Area Development (Golden Eagle) – both of which are operated by another company – in the U.K. portion of the North Sea. Suncor also holds interests in several North Sea licences offshore the U.K. and Norway. Suncor owns, pursuant to a Production Sharing Contract (PSC), an interest in the Ebla gas development in the Ash Shaer and Cherrife areas in Syria. Suncor also owns, pursuant to Exploration and Production Sharing Agreements (EPSAs, a form of PSC), working interests in the exploration and development of oilfields in the Sirte Basin in Libya.

  Due to recent unrest in both countries, the company has declared force majeure under its contractual obligations in Libya and Syria. Operations in Libya are in the process of restarting, while operations in Syria have been suspended indefinitely.

- **North America Onshore** operations include Suncor's interests in a number of assets in Western Canada, which primarily produce natural gas.

REFINING AND MARKETING

Suncor's Refining and Marketing segment consists of two primary operations:

- **Refining and Product Supply** operations refine crude oil into a broad range of petroleum and petrochemical products. Eastern North America operations include refineries located in Montreal, Quebec and Sarnia, Ontario, and a lubricants business located in Mississauga, Ontario that manufactures, blends and markets products worldwide. Western North America operations include refineries located in Edmonton, Alberta, and Commerce City, Colorado. Other assets include interests in a petrochemical plant, pipelines and product terminals in Canada and the U.S.

- Downstream **Marketing** operations sell refined petroleum products and lubricants to retail, commercial and industrial customers through a combination of company-owned, branded-dealer and other retail stations in Canada and Colorado, a nationwide commercial road transport network in Canada, and a bulk sales channel in Canada.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

The grouping **Corporate, Energy Trading and Eliminations** includes the company's investments in renewable energy projects, results related to energy supply and trading activities, and other activities not directly attributable to any other operating segment.

- **Renewable Energy** interests include six operating wind power projects and the St. Clair ethanol plant in Ontario.

- **Energy Trading** activities primarily involve the marketing and trading of crude oil, natural gas, refined petroleum products and byproducts, and the use of midstream infrastructure and financial derivatives to optimize related trading strategies.

- **Corporate** includes stewardship of Suncor's debt and borrowing costs, expenses not allocated to the company's businesses, and the company's captive insurance activities that self-insure a portion of the company's asset base.

- Intersegment revenues and expenses are removed from consolidated results in **Group Eliminations**. Intersegment activity includes the sale of feedstock by the Oil Sands and Exploration and Production segments to the Refining and Marketing segment, the sale of fuels and lubricants by the Refining and Marketing segment to the Oil Sands segment, the sale of ethanol by the Renewable Energy business to the Refining and Marketing segment, and the provision of insurance for a portion of the company's operations by the Corporate captive insurance entity.

4. CONSOLIDATED FINANCIAL INFORMATION

Financial Highlights [1]

Year ended December 31 ($ millions, except per share amounts)	**2011**	2010	2009
Net earnings	**4 304**	3 829	1 146
per common share – basic	**2.74**	2.45	0.96
per common share – diluted	**2.67**	2.43	0.95
Operating earnings [2]	**5 674**	2 634	1 115
per common share – basic	**3.61**	1.69	0.93
Cash flow from operations [2]	**9 746**	6 656	2 799
per common share – basic	**6.20**	4.25	2.34
Dividends paid on common shares	**664**	611	401
per common share	**0.43**	0.40	0.30
Operating revenues (net of royalties)	**39 337**	32 003	17 459
Balance sheet			
Total assets	**74 777**	68 607	69 746
Long-term debt (including current portion)	**10 016**	10 347	13 880
Net debt	**6 976**	11 254	13 377

Segment Highlights [1]

Year ended December 31 ($ millions)	**2011**	2010	2009
Net earnings (loss)			
Oil Sands	**2 603**	1 520	557
Exploration and Production	**306**	1 938	78
Refining and Marketing	**1 726**	819	407
Corporate, Energy Trading and Eliminations	**(331)**	(448)	104
Total	**4 304**	3 829	1 146
Operating earnings (loss) [2]			
Oil Sands	**2 737**	1 379	1 048
Exploration and Production	**1 358**	1 193	150
Refining and Marketing	**1 726**	796	455
Corporate, Energy Trading and Eliminations	**(147)**	(734)	(538)
Total	**5 674**	2 634	1 115
Cash flow from (used in) operations [2]			
Oil Sands	**4 572**	2 777	1 251
Exploration and Production	**2 846**	3 325	1 280
Refining and Marketing	**2 574**	1 538	921
Corporate, Energy Trading and Eliminations	**(246)**	(984)	(653)
Total	**9 746**	6 656	2 799

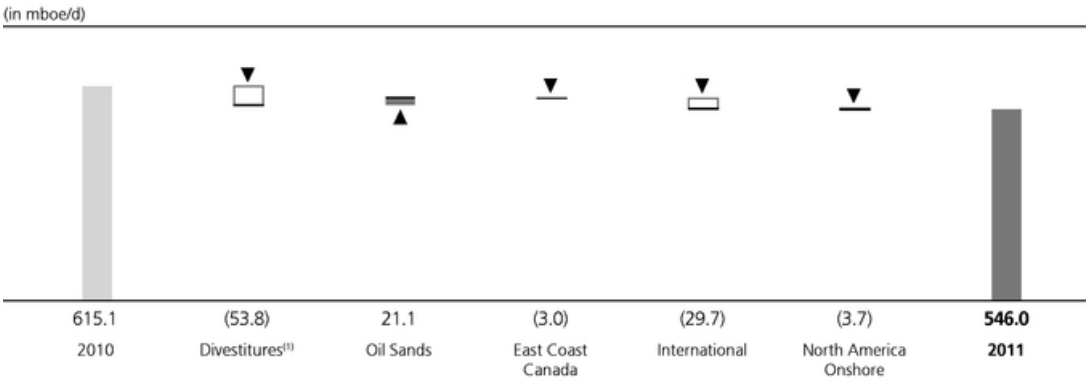
(1) 2009 data is prepared in accordance with Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measures. Operating earnings are reconciled to net earnings in this section of the MD&A under the heading Consolidated Operating Earnings Reconciliation. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings from 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Operating Highlights

Year ended December 31	**2011**	2010	2009
Production volumes (mboe/d)			
Oil Sands	**339.3**	318.2	306.7
Exploration and Production	**206.7**	296.9	149.3
	546.0	615.1	456.0
Average price realizations			
Oil Sands ($/bbl)	**90.07**	70.85	62.53
Exploration and Production ($/boe)	**80.62**	59.47	57.44
	86.49	65.32	47.47
Refined product sales volumes (thousands of m^3/d)			
Eastern North America	**43.5**	45.3	27.7
Western North America	**39.6**	42.0	27.2
	83.1	87.3	54.9

Change in Production Volumes



(1) The volume for divestitures compares annualized 2011 production with total production from 2010 for divested assets. Other figures presented for changes in production volumes include all other factors impacting production volumes.

The decrease in production volumes for 2011, compared with 2010, reflects primarily asset dispositions completed throughout 2010 and 2011. Suncor disposed of non-core natural gas assets in Western Canada and the U.S. Rockies, which contributed approximately 27.4 mboe/d more production than in 2011 (comprised of 23.8 mboe/d from assets disposed in 2010 and 3.6 mboe/d from assets disposed in 2011). Suncor also disposed of non-core North Sea assets, which contributed 19.7 mboe/d more production in 2010, and Trinidad and Tobago assets representing 6.7 mboe/d of 2010 production.

For Oil Sands, the production increase primarily reflected higher output from Oil Sands Base mining and extraction operations and the negative impacts of two upgrader fires at Oil Sands Base on production in the first half of 2010. Production from Syncrude in 2011 decreased slightly compared with 2010, due mainly to operational issues experienced late in 2011.

Excluding the impacts of asset divestitures, for Exploration and Production, decreases for International reflected primarily the shut-in of production in Libya for most of the year due to political unrest and outages at Buzzard for the repair of the cooling system and the completion and commissioning of the fourth platform. These decreases for International were partially offset by a year-over-year increase from Syria, which started producing in April 2010. Decreases for East Coast Canada primarily reflected the partial shut-in of production at Terra Nova due to the presence of hydrogen sulphide (H_2S) in some wells. Decreases for North America Onshore primarily reflected natural declines in reservoir performance.

Net Earnings

Suncor's net earnings for 2011 were $4.304 billion, compared to $3.829 billion in 2010. Net earnings were primarily affected by the same factors that influenced operating earnings, which are described in this section of the MD&A under the heading Operating Earnings. Other items affecting changes in net earnings in 2011, compared with 2010, included:

Operating Earnings Adjustments

- The after-tax unrealized foreign exchange loss on the revaluation of U.S. dollar denominated long-term debt was $161 million in 2011, compared with a gain of $372 million in 2010. During 2011, the US$/Cdn$ exchange rate decreased from 1.01 to 0.98. During 2010, the US$/Cdn$ exchange rate increased from 0.96 to 1.01.

- In 2011, the company recorded net impairment charges of $503 million ($514 million initial impairment, net of $11 million of subsequent impairment reversals) against assets pertaining to its operations in Libya, which were shut-in as a result of unrest. The company also recorded $68 million of after-tax impairment charges against certain North America Onshore assets due to decreasing natural gas prices and after-tax write-offs of crude inventories of $58 million due primarily to third-party pipeline adjustments.

  In 2010, the company recorded after-tax write-offs of $143 million relating primarily to equipment used in an alternative mining and extraction process that was discontinued, after-tax impairment charges of $111 million against certain North America Onshore assets primarily due to decreasing natural gas prices, and after-tax impairment charges of $52 million against non-core U.K. assets that were eventually sold later in 2010 and in 2011.

- In the first quarter of 2011, the U.K. government announced an increase in the tax rate on oil and gas profits in the North Sea that increased the statutory tax rate on Suncor's earnings in the U.K. from 50% to 59.3% in 2011 and to 62% in future years. As a result, the company revalued its deferred income tax balances, resulting in an increase to deferred income tax expense of $442 million.

- In 2011, the company disposed of assets resulting in after-tax losses of $107 million, consisting of $99 million on the partial disposition of interests in the Voyageur upgrader and Fort Hills projects, and $8 million for the sale of non-core Exploration and Production assets.

  In 2010, the company sold several non-core Exploration and Production assets (described in the Segment Results and Analysis – Exploration and Production section of this MD&A) and realized after-tax gains on disposal of $826 million.

- In 2011, Suncor recorded an after-tax provision of $31 million in the Exploration and Production segment related to a royalty dispute concerning the deductibility of certain costs for a period before the merger with Petro-Canada.

  In 2010, Suncor recorded after-tax expenses of $68 million for several other write-offs and provisions related to assets acquired in the merger.

- In 2010, the Oil Sands segment recorded after-tax gains of $233 million related to the change in fair value of certain commodity derivatives, net of realizations, which the company had entered into in previous years to manage the volatility of sales prices for its production.

- In 2010, Suncor recognized an after-tax gain of $166 million for the redetermination of its working interest in the Terra Nova oilfield, upon which the joint owners of Terra Nova reached agreement on a technical review of the interests they contributed.

- In 2010, Suncor recognized a favourable royalty recovery related to modifications made by the Alberta government to the Bitumen Valuation Methodology (BVM) calculation applicable to Suncor for the interim period from January 1, 2009 to December 31, 2010.

Consolidated Operating Earnings Reconciliation (1)(2)(3)

Year ended December 31 ($ millions)	**2011**	2010	2009
Net earnings as reported	**4 304**	3 829	1 146
Unrealized foreign exchange loss (gain) on U.S. dollar denominated long-term debt	**161**	(372)	(798)
Impairments and write-offs	**629**	306	42
Impact of income tax rate adjustments on deferred income taxes	**442**	—	4
Loss (gain) on significant disposals	**107**	(826)	39
Adjustments to provisions for assets acquired through the merger (4)	**31**	68	97
Change in fair value of commodity derivatives used for risk management, net of realizations (5)	—	(233)	499
Redetermination of working interest in Terra Nova	—	(166)	24
Modification of the bitumen valuation methodology	—	(51)	50
Merger and integration costs	—	79	151
Gain on effective settlement of pre-existing contract with Petro- Canada (6)	—	—	(438)
Costs related to deferral of growth projects (7)	—	—	299
Operating earnings	**5 674**	2 634	1 115

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Operating earnings is a non-GAAP financial measure. All reconciling items are presented on an after-tax basis. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(3) The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(4) Adjustment in 2011 related to a royalty dispute for a period prior to the merger. Adjustments in 2010 were for pipeline commitments that the company determined to be unfavourable as a result of certain non-core North America Onshore asset dispositions, the write-off of certain unproven properties in the Exploration and Production segment, changes in the provision for the cancellation of the Montreal refinery coker project, a dry hole in Libya, and other cost estimates associated with the transition to EPSAs in Libya. Adjustments in 2009 included the negative impact associated with inventory acquired at fair value.

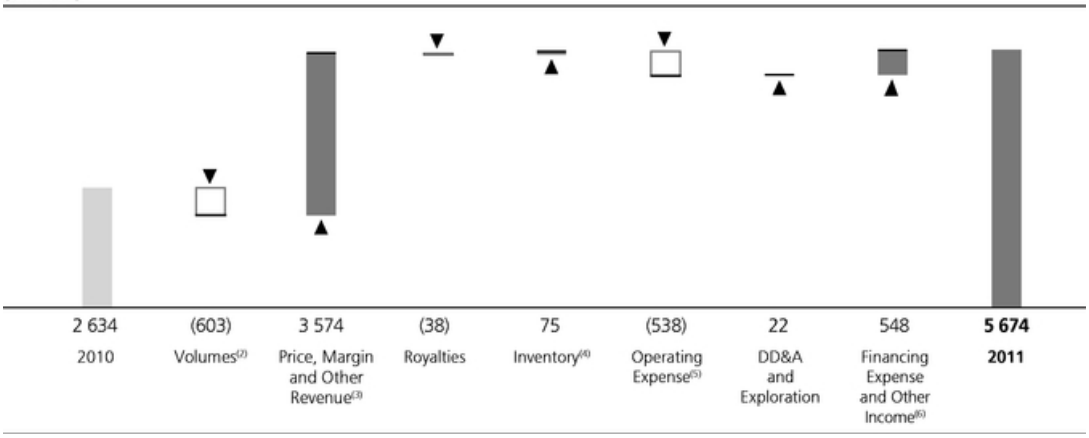
(5) Adjustments represent the change in fair value of significant crude oil risk management derivatives, net of realized gains and losses recognized on the final settlement of those derivatives. The company also holds less significant risk management derivatives for which the company does not adjust net earnings. The company held no significant crude oil risk management derivatives in 2011.

(6) Impact from the deemed settlement value assigned to the bitumen processing contract with Petro-Canada upon close of the merger.

(7) The company incurred costs related to placing certain growth projects into "safe mode" due to unfavourable market conditions in prior years. The company stopped removing these costs from operating earnings effective January 1, 2010. After-tax safe mode costs for the years ended December 31, 2011 and 2010 were approximately $57 million and $94 million, respectively.

Bridge Analysis of Consolidated Operating Earnings(1)

($ millions)



(1) Factors represent after-tax variances and include the impacts of operating earnings adjustments. These factors are analyzed in the Operating Earnings narrative immediately subsequent to this bridge analysis. This bridge analysis is presented because management uses this presentation to analyze performance.

(2) Calculated based on upstream production volumes and Refining and Marketing sales volumes.

(3) Includes upstream price realizations before royalties and transportation costs, refining and marketing margins, other operating revenues, and the net impacts of sales and purchases of third-party crude.

(4) The Inventory variance factor reflects the opportunity cost of building production volumes in inventory or the additional margin earned by drawing down inventory produced in previous periods. The calculation of the Inventory variance factor in this bridge analysis permits the company to present the Volume variance factor for upstream assets based on production volumes, rather than based on sales volumes.

(5) This factor includes transportation expense, operating, selling and general expense and project start-up costs.

(6) This factor also includes changes in gains and losses on disposal of assets that are not operating earnings adjustments, changes in effective income tax rates, and other income tax adjustments.

Operating Earnings

Suncor's consolidated operating earnings [1] for 2011 were $5.674 billion, compared to $2.634 billion in 2010. Positive factors impacting operating earnings in 2011, compared with 2010, included:

- Average price realizations for crude oil production from upstream assets were considerably higher in 2011, consistent with significant increases in benchmark prices for WTI and Brent crudes. The average price realization for the Oil Sands segment in 2011 was $90.07/bbl, compared to $70.85/bbl in 2010. The average price realization for the Exploration and Production segment was $80.62/boe in 2011, compared to $59.47/boe in 2010.

- Refining margins were higher in 2011, reflected by large increases in benchmarks for 3-2-1 crack spreads. Refining margins also benefited from the increasing crude price environment, whereby inventories produced during periods of lower feedstock costs were sold and replaced with inventories purchased at relatively higher feedstock costs.

- Oil Sands production volumes (excluding Syncrude) increased to 304.7 mbbls/d from 283.0 mbbls/d, due primarily to higher bitumen output from Oil Sands Base and In Situ operations. Production volumes from the first half of 2010 were impacted by two upgrader fires.

- Financing expense was lower in 2011 than 2010, due mainly to an increase in capitalized interest (approximately $225 million more capitalized after tax). Suncor capitalized a higher percentage of its borrowing costs due mainly to amounts capitalized for the Voyageur upgrader, Fort Hills and Joslyn projects, subsequent to the completion of transactions with Total E&P.

- Other income was higher in 2011 than 2010, due mainly to higher operating earnings from Suncor's Energy Trading business. In addition, in 2010, the company realized losses on the final settlement of risk management activities pertaining to derivatives the company had entered into in previous years to manage the volatility of sales prices for its production.

- Share-based compensation expense was lower in 2011 than in 2010, due mainly to a decrease in the company's common stock price during the second half of the year. Operating expense for 2011 included after-tax share-based compensation expense of $24 million, whereas operating expense for 2010 included after-tax share-based compensation expense of $146 million.

- The Inventory variance factor was positive, primarily for Oil Sands, because inventories that were produced during the prior year at relatively lower production costs were sold and replaced by inventories produced during the current year at relatively higher production costs.

- DD&A was lower in 2011 than in 2010, due mainly to lower production volumes from Exploration and Production.

The positive factors noted above were partially offset by the following:

- Production volumes for the Exploration and Production segment decreased to 206.7 mboe/d from 296.9 mboe/d, primarily due to the divestiture of non-core assets throughout 2010 and 2011, the shut-in of production in Libya for the majority of 2011, unplanned outages at Buzzard, and the partial shut-in of wells at Terra Nova due to the presence of H_2S.

- Operating expenses, excluding the impacts of share-based compensation expense, were significantly higher in 2011 than in 2010, due mainly to the increase for the Oil Sands segment. Oil Sands Base mining costs were higher and reflected increased bitumen output and higher tonnes of ore moved while working through an area of lower bitumen ore grade quality. Oil Sands Base upgrading costs were higher due mainly to maintenance associated with secondary upgrading units. In Situ costs were higher due mainly to higher operating expenses and start-up costs associated with the Firebag Stage 3 expansion.

- Royalties were higher in 2011 than in 2010, mainly due to higher overall upstream price realizations.

Cash Flow from Operations

Consolidated cash flow from operations [1] for 2011 was $9.746 billion, compared to $6.656 billion in 2010. The increase was mainly due to the same factors that affected the increase in operating earnings, particularly higher upstream price realizations, refining margins and production from Oil Sands.

Results for 2010 compared with 2009

Net earnings for 2010 were $3.829 billion compared to $1.146 billion in 2009. Operating earnings [1] for 2010 were $2.634 billion compared to $1.115 billion in 2009. These increases were due primarily to the inclusion of a full year of operations from assets acquired in the merger with Petro-Canada on August 1, 2009 and higher upstream price realizations.

Upstream production for 2010 averaged 615.1 mboe/d, compared to 456.0 mboe/d in 2009. Downstream refined

product sales averaged 87,300 m^3/d in 2010, compared to 54,900 m^3/d in 2009. Both volumes increased primarily due to new assets acquired in the merger. Higher production also meant higher royalties and DD&A in 2010, compared with 2009. The merger increased Suncor's asset base by approximately $35.8 billion (including goodwill) and long-term debt by $4.4 billion. Net earnings in 2010 included $826 million of after-tax gains on disposal of non-core assets, many of which were acquired through the merger.

Average price realizations were higher in 2010 than in 2009, as increases in important crude benchmarks like WTI and Brent more than offset the impacts of an increasing light/heavy crude differential and the Canadian dollar strengthening against the U.S. dollar.

Much of 2009 was affected by the general economic downturn. Suncor incurred after-tax expenses of $299 million to place certain growth projects in safe mode.

Cash flow from operations (1) was $6.656 billion in 2010, compared to $2.799 billion in 2009, and increased due mainly to the impacts of higher upstream production volumes from assets acquired in the merger and higher average price realizations.

Net debt decreased by $2.1 billion in 2010. Suncor sold non-core assets for total proceeds of approximately $3.5 billion during 2010 and used these funds mainly to reduce total debt.

(1) Operating earnings and cash flow from operations are non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Business Environment

Commodity prices, refining crack spreads and foreign exchange rates are some of the most significant factors that affect the results of Suncor's operations.

(average for the year ended December 31, except as noted)		**2011**	2010	2009
WTI crude oil at Cushing	US$/bbl	**95.10**	79.55	61.80
Dated Brent crude oil at Sullom Voe	US$/bbl	**111.15**	79.50	61.50
Dated Brent/Maya FOB price differential	US$/bbl	**12.50**	9.30	5.00
Canadian 0.3% par crude oil at Edmonton	Cdn$/bbl	**95.75**	78.05	65.80
Light/heavy crude oil differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**17.25**	14.20	9.70
Condensate at Edmonton	US$/bbl	**105.30**	81.90	60.45
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**3.65**	4.15	4.15
New York Harbor 3-2-1 crack (1)	US$/bbl	**27.00**	10.55	8.80
Chicago 3-2-1 crack (1)	US$/bbl	**24.65**	9.00	7.75
Portland 3-2-1 crack (1)	US$/bbl	**28.40**	13.55	11.40
Gulf Coast 3-2-1 crack (1)	US$/bbl	**24.80**	7.90	7.10
Exchange rate	US$/Cdn$	**1.01**	0.97	0.88
Exchange rate (end of period)	US$/Cdn$	**0.98**	1.01	0.96

(1) 3-2-1 crack spreads are indicators of the refining margin generated by converting three barrels of WTI into two barrels of gasoline and one barrel of diesel. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

Suncor's sweet SCO price realizations are influenced primarily by changes in the price for WTI at Cushing. The average WTI price for 2011 increased to US$95.10/bbl from US$79.55/bbl in 2010. The WTI price continued to fluctuate significantly throughout 2011, and at times was as high as US$113/bbl and as low as US$80/bbl. Suncor's price realizations for SCO are also influenced by the supply and demand of sweet SCO from Western Canada. In 2011, sweet SCO averaged trading at a significant premium to WTI.

Suncor produces a specific grade of sour SCO, the price realizations for which are influenced by changes to various crude benchmarks including, but not limited to, Canadian par crude at Edmonton and WCS at Hardisty, but which can also be affected by circumstances underlying spot sales required to manage inventory levels. Similar to WTI, prices for Canadian par crude at Edmonton increased significantly in 2011, compared to 2010. The average Edmonton par price was US$95.75/bbl in 2011 and US$78.05/bbl in 2010.

Bitumen production that Suncor does not upgrade is blended with diluent (or SCO) to facilitate delivery on pipeline systems to customers. Net bitumen price realizations are, therefore, influenced by prices for Canadian heavy crude oil (WCS at Hardisty is a common reference) and prices for diluent (Condensate at Edmonton). Diluent is sourced primarily from the company's own upgrading and refining facilities; however,

purchases of diluent from third parties may be required when the company experiences operational outages. Bitumen price realizations can also be affected by bitumen quality and spot sales to manage inventory levels, and bitumen quality. Average price realizations for bitumen in 2011 were higher than those realized in 2010, due mainly to higher overall crude oil prices partially offset by wider light/heavy differentials and higher prices for diluent.

Suncor's price realizations for production from East Coast Canada and International assets are influenced primarily by the price for Brent crude. Brent crude averaged US$111.15/bbl in 2011, much higher than the average of US$79.50/bbl in 2010. The Brent crude price also fluctuated significantly throughout 2011, averaging over US$100/bbl since February, and at times was as high as US$126/bbl. Brent crude also began to trade at a substantial premium to WTI, averaging US$16.05/bbl for 2011, compared to a small discount of $0.05/bbl in 2010.

Suncor's price realizations for North America Onshore natural gas production are primarily referenced to Alberta spot at AECO. The AECO benchmark averaged $3.65/mcf in 2011, which was lower than the average AECO benchmark of $4.15/mcf in 2010.

Suncor's refining margins are influenced primarily by 3-2-1 crack spreads, which are industry indicators approximating the gross margin on a barrel of crude oil that is refined to produce gasoline and distillates, and by light/heavy and light/sour crude differentials, which indicate when more complex refineries can earn greater margins by processing less expensive, heavier crudes. Crack spreads do not necessarily reflect the margins of a specific refinery because these benchmarks are calculated based off of WTI. In 2011, crack spreads were very high; in part because refined product prices reflected the higher priced Brent crude feedstock of coastal North American markets. This positively benefited Suncor's inland refineries (Sarnia, Edmonton and Commerce City) for much of 2011. Specific refinery margins are further impacted by actual crude purchase costs, refinery configuration and refined product sales markets unique to that refinery's supply orbit.

The majority of Suncor's revenues from the sale of oil and natural gas commodities are based on prices that are determined by, or referenced to, U.S. dollar benchmark prices. The majority of Suncor's expenditures are realized in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease revenue received from the sale of commodities. A decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of commodities.

Conversely, many of Suncor's assets and liabilities are denominated in U.S. dollars, most notably much of the company's long-term debt, and translated to Suncor's reporting currency (Canadian dollars) at each balance sheet date. An increase in the value of the Canadian dollar relative to the U.S. dollar from the previous balance sheet date decreases the Canadian dollars required to settle U.S. dollar denominated obligations and results in unrealized translation gains.

In 2011, although the average US$/Cdn$ exchange rate of 1.01 reflected a stronger relative Canadian dollar over the entire year, the change in the US$/Cdn$ exchange rate from the beginning of the year (1.01) to the end of the year (0.98) impacted the year-end translation of U.S. dollar denominated balances as if the Canadian dollar was relatively weaker.

Economic Sensitivities (1)(2)(3)

The following table illustrates the estimated effects that changes in certain factors would have had on 2011 net earnings and cash flow from operations if the listed changes had occurred.

(Estimated change, in $ millions)	Net Earnings	Cash Flow From Operations
Crude oil +US$1.00/bbl	81	108
Natural gas +Cdn$0.10/mcf	(1)	(1)
Light/heavy differential +US$1.00/bbl	43	58
3-2-1 crack spreads +US$1.00/bbl	109	134
Foreign exchange +$0.01 US$/Cdn$	(37)	(150)

(1) Each line item in this table shows the effects of a change in that variable only, with other variables being held consistent.

(2) Changes for a variable imply that all such similar variables are impacted, such that Suncor's average price realizations increase uniformly. For instance, "Crude oil +US$1.00/bbl" implies that price realizations influenced by WTI, Brent, SCO, WCS, par crude at Edmonton and Condensate all increase by US$1.00/bbl.

(3) Differences between estimates for net earnings and cash flow from operations are due primarily to the impacts of cash taxes in certain jurisdictions.

5. SEGMENT RESULTS AND ANALYSIS

OIL SANDS

Strategy and Operational Update

The Oil Sands business continues to focus on safe, reliable operations that achieve steady production growth while effectively controlling operating costs. We expect our operational excellence initiatives will continuously improve our plant utilization and workforce productivity.

In 2012, Oil Sands Base expects to integrate new mining and upgrading projects that complement its core operations. Oil Sands Base is continuing the ramp up of bitumen production from the NSE, which is expected to reduce mine congestion and lower average haul distances. In addition, Oil Sands Base expects to commission and start up the MNU, which is expected to improve the reliability and availability of its upgrading facilities.

Production growth from the Firebag Stage 3 expansion is on track. Firebag Stage 4 leverages our existing infrastructure and is a smaller project to execute than Stage 3, but is anticipated to bring additional barrels of production equivalent to Stage 3. We expect our portfolio of technology projects will drive improvements and efficiencies in current production and develop future opportunities. This portfolio focuses on both subsurface and surface challenges, such as reducing steam-to-oil ratios and improving the efficiency of steam production and water treatment.

Suncor's transactions with Total E&P closed in March 2011. In order to manage and develop all of the new joint ventures, Suncor created a new business area – Oil Sands Ventures. Throughout 2011, Oil Sands Ventures focused on ensuring the successful restart of the Fort Hills mining and Voyageur upgrader projects, and bringing in operating expertise to complement existing proficiencies and commercial capabilities to effectively manage these new joint ventures. Suncor and the joint venture owners of the Fort Hills, Voyageur upgrader and Joslyn projects have developed a capital program for site preparation and are working towards making decisions regarding the sanctioning of these projects in 2013.

Financial Highlights (1)

Year ended December 31 ($ millions)	**2011**	2010	2009
Gross revenues	**13 001**	9 690	6 744
Less: Royalties	**(799)**	(681)	(645)
Operating revenues, net of royalties	**12 202**	9 009	6 099
Net earnings	**2 603**	1 520	557
Operating earnings (2)	**2 737**	1 379	1 048
Cash flow from operations (2)	**4 572**	2 777	1 251

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Oil Sands net earnings for 2011 were $2.603 billion, compared to $1.520 billion in 2010. Net earnings for 2011 included an after-tax loss of $99 million on the sale of partial interests in the Voyageur upgrader project and the Fort Hills mining project, and an after-tax write-off of $35 million for third-party pipeline adjustments. Net earnings for 2010 included after-tax gains of $233 million for the change in fair value of commodity derivatives used for risk management, net of realizations, and $51 million for a recovery of royalties pertaining to a change in Suncor's BVM, partially offset by after-tax write-offs of $143 million primarily associated with equipment for an alternative mining and extraction process that was discontinued.

Operating earnings for 2011 were $2.737 billion, compared to $1.379 billion in 2010, and increased primarily due to higher average price realizations and higher production volumes, offset by higher operating expenses and DD&A.

Cash flow from operations for 2011 were $4.572 billion, compared to $2.777 billion in 2010, and increased primarily due to higher margins, which were driven by higher price realizations and higher production volumes.

Operating Earnings

Operating Earnings Reconciliation [1]

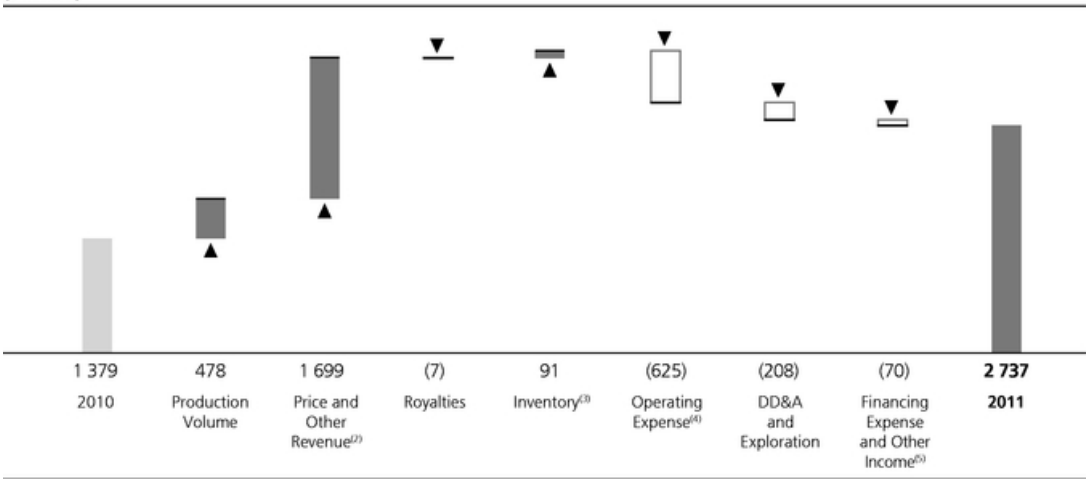
Year ended December 31 ($ millions)	**2011**	2010	2009
Net earnings as reported	**2 603**	1 520	557
Loss on significant disposals	**99**	—	39
Impairments and write-offs	**35**	143	—
Change in fair value of commodity derivatives used for risk management, net of realizations	**—**	(233)	499
Modification of the bitumen valuation methodology	**—**	(51)	50
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	—	(438)
Costs related to deferral of growth projects	**—**	—	299
Impact of income tax rate adjustments on deferred income taxes	**—**	—	37
Adjustments to provisions for assets acquired through the merger	**—**	—	5
Operating earnings [2]	**2 737**	1 379	1 048

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measure. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Operating Earnings[1]

($ millions)



(1) Factors represent after-tax variances and include the impacts of operating earnings adjustments. These factors are analyzed in the narrative immediately subsequent to this bridge analysis. This bridge analysis is presented because management uses this presentation to analyze performance.

(2) Includes price realizations before royalties and transportation costs, other operating revenues and the net impacts of sales and purchases of third-party crude.

(3) The Inventory variance factor reflects the opportunity cost of building production volumes in inventory or the additional margin earned by drawing down inventory produced in previous periods. The calculation of the Inventory variance factor in this bridge analysis permits the company to present the Volume variance factor based on production volumes, rather than based on sales volumes.

(4) This factor includes transportation expense, operating, selling and general expense, and project start-up costs.

(5) This factor also includes changes in gains and losses on disposal of assets that are not operating earnings adjustments, changes in effective income tax rates, and other income tax adjustments.

Production Volumes

Year ended December 31	**2011**	2010	2009
Oil Sands (mbbls/d)	**304.7**	283.0	290.6
Oil Sands Ventures (mbbls/d)	**34.6**	35.2	16.1
Total (mbbls/d)	**339.3**	318.2	306.7

Production volumes from Oil Sands (excluding Syncrude) in 2011 averaged 304.7 mbbls/d, compared to 283.0 mbbls/d in 2010, and increased mainly due to operational improvements at the company's mining and extraction operations, reflected by a 12% increase in bitumen ore tonnes mined. Production from the first half of 2010 was impacted by two upgrader fires. In 2011, Suncor successfully completed the largest planned maintenance event in its history at its Upgrader 2 facilities, lasting approximately six weeks; the impact of this event on 2011 production was greater than the two relatively smaller planned maintenance events completed in 2010.

Oil Sands achieved a single-month production record of 345,000 bbls/d in December, reflecting higher bitumen output from In Situ operations and an increase in bitumen ore tonnes mined, partially offset by lower bitumen ore grade quality at the Millennium mine face. Suncor anticipates that lower bitumen ore grade quality will continue to impact operations until the start of the fourth quarter of 2012, at which point the bitumen ore grade quality is expected to return to previous levels.

In Situ bitumen production volumes averaged 89.5 mbbls/d in 2011, compared to 85.1 mbbls/d in 2010. Output from Firebag averaged 59.5 mbbls/d in 2011, an 11% increase from 53.6 mbbls/d in 2010. This increase was due mainly to new production starting in the second half of 2011 from the first well pad for the Stage 3 expansion and from new infill wells completed on existing well pads. MacKay River production averaged 30.0 mbbls/d in 2011, down slightly from 2010 production of 31.5 mbbls/d. Overall MacKay River production levels have been at or around nameplate capacity (approximately 30,000 bbls/d) since 2009. The company anticipates that new wells coming on-stream in the fourth quarter of 2011 and throughout 2012, combined with well workovers, will offset natural declines from existing well pairs. Bitumen production from Suncor's In Situ operations exited 2011 at approximately 111,000 bbls/d.

For Oil Sands Ventures, Suncor's share of Syncrude production decreased to 34.6 mbbls/d in 2011, compared to 35.2 mbbls/d in 2010. Production in 2011 was negatively impacted by operational issues with a hydrogen plant following the planned maintenance event in the fall.

Average Price Realizations and Sales Volumes (1)

Year ended December 31	**2011**	2010	2009
Oil Sands ($/bbl)	**88.74**	69.58	61.66
– relative to WTI (Cdn$/bbl)	**(5.35)**	(12.33)	(9.59)
Sales volumes (mbbls/d)	**304.4**	279.3	276.2
Sales mix (sweet/sour) (%)	**36/64**	37/63	47/53
Oil Sands Ventures ($/bbl)	**101.80**	80.93	77.36

(1) Average price realizations are before royalties and net of related transportation costs, and include the impact of realized derivative gains and losses.

Oil Sands sales volumes (excluding Syncrude) increased in 2011, compared with 2010. The sweet/sour sales mix for 2011 (36%/64%) was slightly lower than 2010 (37%/63%). The Upgrader 1 hydrogen plant experienced several outages over the second half of 2010 and into the first half of 2011. The company completed maintenance on these units and, as a result, the sweet/sour sales mix for the fourth quarter of 2011 was 46%/54%.

Average price realizations for Oil Sands sales were $88.74/bbl (WTI less $5.35/bbl) in 2011, compared to $69.58/bbl (WTI less $12.33/bbl) in 2010, and increased mainly due to higher benchmark prices for crude oil. The average price realization for sales relative to WTI improved due mainly to higher differentials for SCO compared to WTI. Suncor's average price realization for Syncrude sales in 2011 was $101.80/bbl, compared to $80.93/bbl in 2010, and was higher due to higher benchmark prices for crude oil and higher differentials between SCO and WTI.

Royalties

Royalties were slightly higher in 2011 than in 2010. Oil Sands royalties are influenced primarily by the valuation for bitumen, which was approximately 10% higher in 2011. In Situ royalties were also higher because MacKay River reached the higher, post-payout phase as determined by regulation in November 2010. These increases were partially offset by increased capital expenditures for royalty-eligible capital expenditures (primarily the TRO$_{TM}$ project). Royalties in 2010 were impacted by the receipt of business interruption insurance proceeds, which were subject to royalty, related to the upgrader fires in 2009 and 2010.

For 2011, Suncor continued to remit royalty payments under its BVM for production from Oil Sands Base operations based on its view of reasonable quality adjustments; however, royalty expense was calculated based on the quality adjustment enacted by the Alberta government in December 2010. Suncor's Royalty Amending Agreement (the Suncor RAA) provides for an arbitration procedure failing settlement of these issues. Suncor filed a Notice of Commencement of Arbitration with the Alberta government on January 29, 2011.

Inventory

The Inventory variance factor was positive because inventories produced during the prior year at relatively lower production costs were sold and replaced by inventories produced during the current year at relatively higher production costs.

Oil Sands Cash Operating Costs (1)

Year ended December 31	**2011**	2010	2009
Oil Sands cash operating costs ($ millions)	**4 479**	3 990	3 599
Oil sands cash operating costs ($/bbl)	**40.20**	38.65	33.95

(1) Oil Sands cash operating costs is a non-GAAP financial measure, and is reconciled to operating, selling and general expense in the Non-GAAP Financial Measures Advisories section of this MD&A.

Oil Sands cash operating costs per barrel increased in 2011, averaging $40.20/bbl, compared to $38.65/bbl in 2010, with the impact of higher total Oil Sands cash operating costs (+$4.40/bbl) partially offset by the impact of higher Oil Sands production (-$2.85/bbl). Oil Sands cash operating costs per barrel increased more noticeably in the fourth quarter of 2011, mainly because of the ramp up of the Firebag Stage 3 expansion and higher mining costs necessary to maintain bitumen supply while working through the lower ore grade quality zone at the Millennium mine face and to remove more tonnes of overburden.

Oil Sands cash operating costs increased to $4.479 billion in 2011 from $3.990 billion in 2010. Within this total, In Situ cash operating costs increased significantly compared to 2010, due mainly to higher expenses for labour, maintenance, natural gas and support, most of which was associated with the Firebag Stage 3 expansion. For Oil Sands Base operations, upgrading costs were higher primarily as a result of maintenance related to the restart of the Upgrader 1 hydrogen plant, and mining costs were higher, due mainly to a larger workforce and higher maintenance and rentals to support increased bitumen output.

Expenses and Other Factors

Operating expenses at Syncrude were higher in 2011 than 2010, due primarily to increased maintenance stemming from operational issues, and higher diesel fuel costs, which reflected higher prices and higher overall consumption.

In addition, other operating expenses were lower in 2011 than 2010, primarily due to lower share-based compensation expense and lower costs related to the deferral of growth projects. These decreases were partially offset by higher project start-up costs related to the Firebag Stage 3 expansion and commissioning of the MNU.

The company continues to incur costs related to remobilizing certain growth projects out of "safe mode" after the economic downturn in late 2008 and early 2009. Pre-tax safe mode costs for 2011 were $76 million, compared to $126 million in 2010. Safe mode costs include the costs for maintaining equipment and facilities related to projects still in safe mode, the costs to assess the condition of assets coming out of safe mode, and the costs of remobilizing equipment and personnel.

DD&A expense for 2011 was higher than 2010, due mainly to a larger asset base that is the result of costs capitalized for recently commissioned In Situ assets and significant planned maintenance events in 2010 and 2011.

Other income was lower in 2011 than in 2010, mainly due to insurance proceeds received from Suncor's captive insurance company in 2010 related to the 2009 and 2010 upgrader fires.

Planned Maintenance Events

During the second quarter of 2011, the company successfully completed a six-week planned maintenance event safely and on schedule. The scope of this event, associated with Oil Sands Base Upgrader 2 facilities, was the largest in Suncor's history.

In the second quarter of 2012, the company expects to shut down one coker unit at Upgrader 1. In the third quarter of 2012, the company expects to complete maintenance on the vacuum tower and shut down one coker unit at Upgrader 2. The company is also currently planning to complete maintenance on secondary upgrading units at both Upgrader 1 and Upgrader 2 during 2012.

Arrangements with Total E&P

During the first quarter of 2011, Suncor completed transactions with Total E&P, which brought Total E&P into the Voyageur upgrader project and increased Total E&P's working interest in the Fort Hills oil sands mining project, and which brought Suncor into the Joslyn oil sands mining project. In consideration for Total E&P acquiring a 49% interest in the Voyageur upgrader project, an additional 19.2% interest in the Fort Hills project, rights to certain knowledge and technology licences, and Total E&P assuming its share of capital expenditures subsequent to the transaction effective date of January 1, 2011, Suncor received $2.662 billion from Total E&P, net of transaction costs. Suncor recorded an after-tax loss of $99 million on the partial disposition of its assets, which included a reduction of $267 million to goodwill that the company

allocated to its disposed interests. The after-tax loss was modified in the fourth quarter of 2011 following adjustments finalized during the closing period. In consideration for Suncor acquiring a 36.75% interest in Joslyn and assuming its share of capital expenditures subsequent to the effective date, Suncor paid Total E&P $842 million.

Results for 2010 compared with 2009

Oil Sands net earnings for 2010 were $1.520 billion, compared to $557 million in 2009. Net earnings in 2010 were positively impacted by gains related to the change in fair value of certain risk management derivatives, but negatively impacted by the write-off of mining and extraction equipment. Net earnings in 2009 were negatively impacted by losses related to the change in fair value of certain risk management derivatives, net of realizations, and by costs related to the deferral of growth projects triggered by the general economic downturn in 2008, but positively impacted by a gain related to the merger on the effective settlement of a pre-existing contract with Petro-Canada to upgrade MacKay River bitumen production.

Operating earnings for 2010 were $1.379 billion, compared to $1.048 billion in 2009. The increase was due mainly to higher overall price realizations that reflected higher benchmark prices and a full year of production from Suncor's share in Syncrude. This increase was partially offset by lower production from Oil Sands during the first half of 2010, due mainly to the impacts of the two upgrader fires, lower sweet/sour sales mix that was negatively impacted by the upgrader fires and operational issues with secondary upgrading facilities at Upgrader 1, and higher operating expenses mainly due to the upgrader fires.

Cash flow from operations for 2010 was $2.777 billion, compared to $1.251 billion in 2009. The increase in cash flow from operations was mainly due to the same factors that affected operating earnings.

EXPLORATION AND PRODUCTION

Strategy and Operational Update

Suncor's Exploration and Production operations are comprised primarily of conventional upstream assets that have lower operating costs and require less reinvestment to maintain production than unconventional oil sands assets. Over two-thirds of 2011 production from this segment received prices based on Brent crude, which traded at a significant premium to WTI for much of 2011. As a result, the Exploration and Production segment generated significant cash flow in 2011 despite lower production volumes, and is an important source of funding for Suncor's long-term growth strategy.

Production growth from Exploration and Production is also an important element of Suncor's long-term strategy. The development of the Golden Eagle, Hibernia Southern Extension Unit (HSEU), White Rose Extensions and Hebron all provide what the company believes are attractive opportunities to grow low-cost production and generate future cash flow.

In 2011, Exploration and Production faced many challenges. Operations were suspended for much of the year in Libya and were recently suspended in Syria. Production from Terra Nova was constrained by H_2S issues, and production from the non-operated Buzzard platform experienced periods of lower rates due to operational issues. Suncor continues to see opportunity to further rightsize its asset base by divesting non-core properties in North America Onshore. However, poor market conditions for natural gas assets in Western Canada in 2011 offered limited opportunities that met the company's financial objectives.

For 2012, the effective execution of projects at our offshore assets, such as the dockside maintenance program for Terra Nova, is expected to set the company up for continued success. Exploration activities in the North Sea are expected to be associated with the Beta discovery and the Romeo prospect. Elsewhere, we are directing attention to continued cost reductions and unconventional and liquids-rich plays in our North America Onshore operations, and the restart of production from Libya provides the company with a cautiously optimistic outlook about a full return to business in that country.

Financial Highlights [1]

Year ended December 31 ($ millions)	**2011**	2010	2009
Gross revenues	**6 784**	7 043	2 858
Less: Royalties	**(1 472)**	(1 377)	(554)
Operating revenues, net of royalties	**5 312**	5 666	2 304
Net earnings	**306**	1 938	78
Operating earnings [2]	**1 358**	1 193	150
Cash flow from operations [2]	**2 846**	3 325	1 280

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See also the Non-GAAP Financial Measures Advisory section of this MD&A.

Exploration and Production net earnings for 2011 were $306 million in 2011, compared to $1.938 billion in 2010. Net earnings in 2011 were impacted by after-tax impairment charges of $503 million against assets in Libya ($514 million initial impairment, net of $11 million of subsequent impairment reversals) as a result of the shut-in of production and $68 million against certain North America Onshore properties due to decreasing natural gas prices. Net earnings in 2011 were also impacted by a deferred income tax expense adjustment of $442 million pertaining to an increase in the U.K. tax rate on oil and gas profits in the North Sea, an after-tax provision of $31 million pertaining to a royalty dispute covering a period from before the merger, and after-tax losses on disposal of non-core assets of $8 million. Net earnings in 2010 included after-tax gains on disposal of non-core assets of $826 million, an after-tax gain of $166 million for the redetermination of Suncor's working interest in Terra Nova, after-tax impairment charges of $111 million on certain North America Onshore assets mainly due to lower natural gas prices, an after-tax provision for $84 million related to losses on unfavourable natural gas pipeline commitments, and after-tax impairment charges of $52 million on non-core U.K. assets that were sold later in 2010 and the first quarter of 2011.

Operating earnings for 2011 were $1.358 billion, compared to $1.193 billion in 2010. The increase in operating earnings was primarily due to higher average price realizations and lower operating expenses and DD&A, partially offset by lower production volumes, higher royalties and a higher effective tax rate on U.K. earnings.

Cash flow from operations was $2.846 billion in 2011, compared to $3.325 billion in 2010. The decrease in cash flow from operations relative to the increase in operating earnings is due primarily to lower production from assets in 2011 that contributed relatively more to cash flow from operations than operating earnings in 2010. In addition, cash flow from operations in 2010 included the gain from the settlement pertaining to the redetermination of working interests in Terra Nova.

Operating Earnings

Operating Earnings Reconciliation [1]

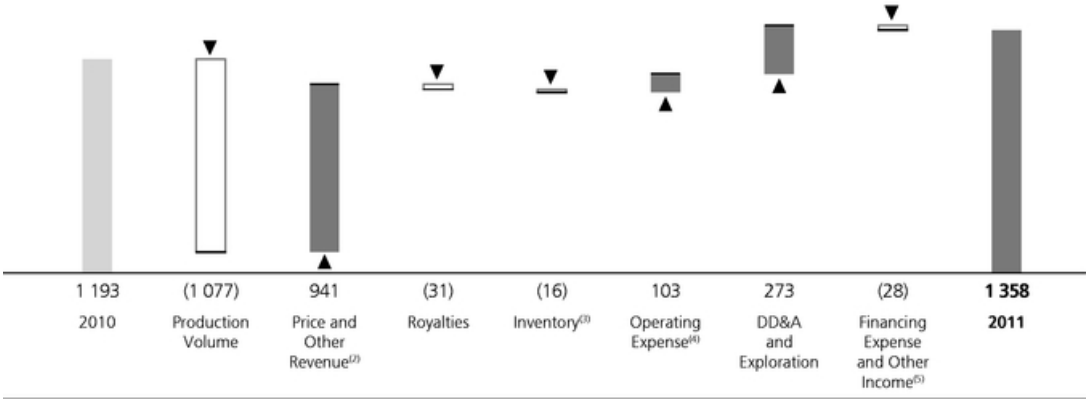
Year ended December 31 ($ millions)	**2011**	2010	2009
Net earnings as reported	**306**	1 938	78
Impairments and write-offs	**571**	163	42
Impact of income tax rate adjustments on deferred income taxes	**442**	—	(19)
Adjustments to provisions for assets acquired through the merger	**31**	84	25
Loss (gain) on significant disposals	**8**	(826)	—
Redetermination of working interest in Terra Nova	**—**	(166)	24
Operating earnings [2]	**1 358**	1 193	150

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measure. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Operating Earnings[1]

($ millions)



(1) Factors represent after-tax variances and include the impacts of operating earnings adjustments. These factors are analyzed in the narrative immediately subsequent to this bridge analysis. This bridge analysis is presented because management uses this presentation to analyze performance.

(2) Includes price realizations before royalties and transportation costs, other operating revenues and the net impacts of sales and purchases of third-party crude.

(3) The Inventory variance factor reflects the opportunity cost of building production volumes in inventory or the additional margin earned by drawing down inventory produced in previous periods. The calculation of the Inventory variance factor in this bridge analysis permits the company to present the Volume variance factor based on production volumes, rather than based on sales volumes.

(4) This factor includes transportation expense and operating, selling and general expense.

(5) This factor also includes changes in gains and losses on disposal of assets that are not operating earnings adjustments, changes in effective income tax rates, and other income tax adjustments.

Production Volumes [1]

Year ended December 31	**2011**	2010	2009
Production volumes			
East Coast Canada (mbbls/d)	**65.6**	68.6	24.3
International (mboe/d)	**76.4**	132.5	50.6
North America Onshore (mmcfe/d)	**388**	575	446
Total production (mboe/d)	**206.7**	296.9	149.3
Mix (liquids/gas) (%)			
East Coast Canada	**100/0**	100/0	100/0
International	**82/18**	87/13	84/16
North America Onshore	**8/92**	9/91	11/89
Total production	**64/36**	63/37	50/50

(1) Production volumes for 2009 represent Suncor's share of production from assets acquired in the merger with Petro-Canada from August 1, 2009 to December 31, 2009.

East Coast Canada production averaged 65.6 mbbls/d in 2011, compared to 68.6 mbbls/d in 2010.

- Production from Terra Nova in 2011 was lower than 2010 by 7.0 mbbls/d and was affected for the entire year by the partial shut-in of certain wells due to the presence of H_2S. Production from Terra Nova increased later in 2011, subsequent to the completion of a new production well and the replacement of a subsea flow line that added back production from certain shut-in wells.

- Production from White Rose in 2011 was higher than 2010 by 4.0 mbbls/d and increased mainly due to higher production from the North Amethyst portion of the White Rose Extensions, which began producing in 2010.

- Production from Hibernia in 2011 was consistent with production in 2010. In 2011, Hibernia achieved first oil from the HSEU. At this time, Suncor does not anticipate significant incremental or sustained production from the HSEU until further development drilling and subsea infrastructure comes on-stream, which is planned for 2014.

International production averaged 76.4 mboe/d in 2011 compared to 132.5 mboe/d in 2010.

- Production from the North Sea in 2011 decreased by 32.3 mboe/d, compared with 2010, with 12.6 mboe/d of the decrease occurring at Buzzard. In 2011, production from Buzzard was impacted by production constraints due to fluctuating rates associated with the replacement of the gas compression cooling system, downtime and capacity constraints on a third-party export pipeline, and other outages that coincided with the commissioning of the fourth platform. The remaining production decrease from the North Sea was due to the disposal of non-core assets in the U.K. and

the Netherlands throughout 2010 and into the first quarter of 2011.

- Production from Libya in 2011 averaged 12.1 mbbls/d, compared to 35.2 bbls/d in 2010. Production from Libya was shut in starting in February due to the outbreak of political unrest. As a result of the unrest and subsequent sanctions introduced against the Libyan government, the company declared force majeure under its contractual obligations. Subsequent to the government regime change and the lifting of sanctions, production was restarted later in the year in three of five fields.

- Production from Syria averaged 17.6 mboe/d in 2011, up from 11.6 mboe/d in 2010, primarily because first gas from the Ebla project was achieved in April 2010 and first oil in December 2010. However, unrest in Syria led to international sanctions in December 2011 that prohibited transactions with Suncor's joint venture partner, and, as a result, the company declared force majeure under its contractual obligations and ceased recording further production.

- Production for International in 2010 also included 6.7 mboe/d from the company's Trinidad and Tobago assets, which were divested in the third quarter of 2010.

North America Onshore production for 2011 decreased to 388 mmcfe/d from 575 mmcfe/d in 2010. The decrease was due primarily to disposals of non-core assets throughout 2010 and 2011 that contributed incremental production of approximately 164 mmcfe/d in 2010 and average production of 21 mmcfe/d in 2011. Production from remaining properties decreased approximately 10% compared with 2010, due primarily to natural declines in reservoir performance.

Average Price Realizations (1)

Year ended December 31	**2011**	2010	2009
East Coast Canada ($/bbl)	**108.42**	80.20	76.86
International ($/boe)	**100.89**	74.92	72.65
North America Onshore ($/mcfe)	**4.39**	4.70	4.31

(1) Average price realizations are calculated before royalties and net of transportation costs.

Average price realizations in 2011 for sales of crude oil from East Coast Canada and International assets were significantly higher than 2010, due mainly to higher Brent crude prices.

Average price realizations for North America Onshore production were lower in 2011, mainly due to lower benchmark prices for natural gas at AECO. This decrease was partially offset by higher average price realizations for sales of crude oil and natural gas liquids, due mainly to higher prices for WTI.

Royalties

Royalties were higher in 2011, compared with 2010, due to higher price realizations, partially offset by the shut-in of production in Libya and lower production volumes from North America Onshore.

Expenses and Other Factors

Operating expenses and DD&A were lower in 2011 than in 2010, mainly due to the disposition of non-core assets throughout 2010 and 2011 and the suspension of operations in Libya. Exploration expense also decreased, mainly due to exploration activities in Libya being suspended and exploration well write-offs in 2010 in the Netherlands and Norway portions of the North Sea.

Other factors that impacted operating earnings in 2011, compared with 2010, included the effects of the higher tax rate that the U.K. government enacted in the first quarter of 2011.

Planned Maintenance Events

A dockside maintenance program is scheduled for the Terra Nova FPSO vessel for an estimated 21-week period during the second half of 2012. The company anticipates a return to the field with resumption of production prior to the end of 2012. The planned work includes the replacement of the FPSO water injection swivel and the completion of the replacement of subsea infrastructure to remediate H_2S issues.

An extended, 18-week off-station maintenance program is scheduled to commence in the second quarter of 2012 for the White Rose FPSO, primarily to address issues with the FPSO propulsion system.

During these outages, there will be no production from the respective assets.

Smaller planned maintenance events are scheduled to occur at Hibernia and Buzzard in the third quarter of 2012.

Asset Dispositions

During 2011, the company disposed of certain non-core asset packages from its North America Onshore operations for net proceeds of $164 million, resulting in after-tax gains on disposition of $82 million. These divested assets contributed average production of approximately 35 mmcfe/d in 2010. Current market conditions for further dispositions are limiting opportunities that meet the company's financial objectives.

On March 31, 2011, the company completed its sale of non-core U.K. offshore assets (primarily Scott and Triton). Final net proceeds were £90 million (Cdn$140 million) and the related after-tax loss on disposition was $90 million.

During 2010, the company divested other assets:

- Throughout the year, the company completed the sale of a number of non-core North America Onshore properties for net proceeds of approximately $1.7 billion.
- In the third quarter, the company completed the sale of its shares in Petro-Canada Netherlands BV for net proceeds of €316 million (Cdn$420 million).
- In the third quarter, the company completed the sale of its assets in Trinidad and Tobago for net proceeds of US$378 million (Cdn$383 million).
- A portion of the sale of the non-core U.K. offshore assets was completed in the fourth quarter for net proceeds of £55 million (Cdn$86 million).

Update on the Impacts of Events in Libya

Following the regime change in Libya in the second half of 2011, Suncor's joint venture in Libya, Harouge Oil Operations BV (Harouge), successfully restarted production in all significant fields and work continues to stabilize production levels. Suncor's share of production exiting December 2011 was approximately 30,000 bbls/d. Suncor remains optimistic about a gradual return to full operations in Libya and is working to remove its EPSAs from force majeure.

In light of the uncertainty surrounding the situation in Libya at the end of the second quarter of 2011, management made an assessment that it may not be able to re-enter Libya for a period of one to two years, if at all, and that any resumption of operations may involve additional remedial expenditure. The company, therefore, determined that its assets in Libya were impaired and recorded charges of $259 million (net of income taxes of $nil) against producing assets in property, plant and equipment, $211 million (net of income taxes of $nil) against exploration and evaluation assets and $44 million (net of income taxes of $nil) against crude oil and materials inventories. Later in the year, the company was able to confirm the existence and sale of crude inventories and reversed impairment charges of $11 million (net of income taxes of $nil).

Suncor has re-engaged with the National Oil Company of Libya to discuss current operations and future plans; however, there is still sufficient unpredictability underlying operating in this region, including the time frame for the ramp up of production, future exploration commitments, and the extent of damage to the company's assets, which has not yet been fully assessed. Therefore, as at December 31, 2011, there have been no further changes in the company's assessment of the impairment recognized in the second quarter.

For further information about the impairment process, see the Accounting Policies and Critical Accounting Estimates section of this MD&A.

Update on the Impacts of Events in Syria

In December 2011, amid continuing unrest in Syria, sanctions were introduced that required Suncor to declare force majeure under its contractual obligations and suspend operations in the country. Suncor withdrew its expatriate staff and undertook measures to maintain support for its Syrian employees. Consequently, the company ceased recording all production and revenue associated with its Syrian assets. If force majeure is lifted in the future, the company expects it will have the right to recover its share of any production occurring during the force majeure period.

Suncor has not received payment for recent production. Suncor believes it is entitled to these receivables and will work with its joint venture partner to receive payment if and when the sanctions are removed. In accordance with GAAP, because of the uncertainty associated with collecting these amounts as a result of the political unrest and sanctions in Syria, Suncor has recorded an after-tax provision of $63 million against these receivables, which represents approximately half of the overall balance outstanding.

Suncor has estimated the net recoverable value of its assets in Syria based on an assessment of expected future net cash flows over a range of possible outcomes. The result of this assessment did not require Suncor to record an impairment charge against its assets in Syria at December 31, 2011. Should the current situation in Syria be resolved in a timely manner, such that sanctions are lifted, PSCs and sales agreements resume unaltered, and payments for sale of hydrocarbons are received, we would expect that the value of Suncor's net assets in Syria would not be impaired. However, should the current situation persist or worsen, such that Suncor is unable to resume operations in the near term, the company believes its assets in Syria could be impaired in the future. Suncor's operations in Syria represented approximately 3% of the company's consolidated net earnings and cash flow from operations in 2011. The carrying value of Suncor's net assets in Syria at December 31, 2011 was approximately $900 million. For further information about the impairment process, see the Accounting Policies and Critical Accounting Estimates section of this MD&A.

As part of its normal course of operations, Suncor carries risk mitigation instruments in the aggregate amount of $405 million (pre-tax) on certain foreign operations, of which up to $300 million may apply to our assets in Syria.

Results for 2010 compared with 2009

Exploration and Production net earnings in 2010 were $1.938 billion, compared to $78 million in 2009. Net earnings in 2010 included after-tax gains of $826 million on the disposal of non-core assets and an after-tax gain of $166 million for the redetermination of the company's working interest in Terra Nova, partially offset by after-tax impairments of $163 million.

Operating earnings for 2010 were $1.193 billion, compared to $150 million in 2009, and cash flow from operations was $3.325 billion in 2010, compared to $1.280 billion in 2009. All East Coast Canada and International production, and approximately 70% of 2010 North America Onshore production was acquired in the merger with Petro-Canada. Price realizations were higher in 2010 primarily due to higher benchmark prices for Brent crude.

REFINING AND MARKETING

Strategy and Operational Update

In 2011, the integrated network of Suncor's Refining and Marketing segment created significant value through its strategic assets, geographic leverage and product differentiation. The location and reliability of the Edmonton, Sarnia and Commerce City refineries enabled the capture of attractive inland crude differentials related to record high discounts for WTI compared to Brent crude. The integration of these refineries with crude output from Suncor's Oil Sands segment also resulted in lower feedstock costs. In addition, Suncor's strategy of positioning its marketing demands to exceed its refining capacity has enabled the refineries to keep crude throughputs high and spread fixed refining costs over a broader production base.

Suncor's strategy of leveraging high-value internal channels in its Marketing business was also very successful in 2011, with strong sales volumes and margins, boosting segment earnings beyond the refinery gate. Suncor's Petro-Canada branded outlets continue to be a leading retailer by market share in major urban areas of Canada.

For 2012, Refining and Marketing will continue to focus on the safety and reliability of its operations, leverage the strong brand to increase non-petroleum revenues through the company's network of convenience stores and car washes, and expand the lubricants product offering.

Financial Highlights (1)

Year ended December 31 ($ millions)	**2011**	2010	2009
Operating revenues	**25 713**	20 860	11 851
Net earnings	**1 726**	819	407
Operating earnings (2)			
Refining and Product Supply	**1 413**	532	311
Marketing	**313**	264	144
	1 726	796	455
Cash flow from operations (2)	**2 574**	1 538	921

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Refining and Marketing had net and operating earnings of $1.726 billion in 2011, compared with net earnings of $819 million and operating earnings of $796 million in 2010.

Refining and Product Supply operations contributed $1.413 billion to operating earnings in 2011, a significant increase compared with 2010, primarily due to higher refining margins and the positive impacts of an increasing crude price environment, whereby inventories produced during periods of lower feedstock costs were sold and replaced with inventories purchased at relatively higher feedstock costs. Marketing operations contributed $313 million to operating earnings in 2011, which was higher than in 2010, due mainly to strong demand and margins in wholesale and lubricants channels.

Cash flow from operations was $2.574 billion in 2011, compared to $1.538 billion in 2010, and increased primarily due to the same factors that affected operating earnings.

Operating Earnings

Operating Earnings Reconciliation [1]

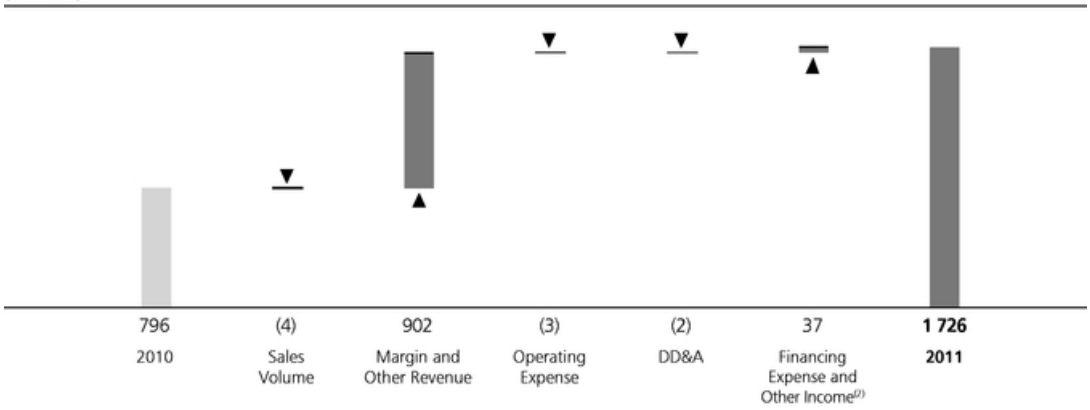
Year ended December 31 ($ millions)	**2011**	2010	2009
Net earnings as reported	**1 726**	819	407
Adjustments to provisions for assets acquired through the merger	**—**	(23)	67
Impact of income tax rate adjustments on deferred income taxes	**—**	—	(19)
Operating earnings [2]	**1 726**	796	455

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measure. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Operating Earnings[1]

($ millions)



(1) Factors represent after-tax variances and include the impacts of operating earnings adjustments. These factors are analyzed in the narrative immediately subsequent to this bridge analysis. This bridge analysis is presented because management uses this presentation to analyze performance.

(2) This factor also includes changes in gains and losses on disposal of assets that are not operating earnings adjustments, changes in effective income tax rates, and other income tax adjustments.

Volumes

Year ended December 31	**2011**	2010	2009
Refined product sales (thousands of m^3/d)			
Gasoline	**39.7**	41.1	27.6
Distillate [1]	**30.4**	30.4	18.3
Other	**13.0**	15.8	9.0
	83.1	87.3	54.9
Refinery utilization [2][3] (%)			
Eastern North America	**94**	89	87
Western North America	**91**	95	97
Crude oil processed [4] (thousands of m^3/d)			
Eastern North America	**32.0**	30.5	29.6
Western North America	**32.8**	34.6	33.6

(1) Previously disclosed distillate sales volumes have been adjusted to remove certain volumes that originated from Oil Sands.

(2) Refinery utilization is the amount of crude oil and natural gas plant liquids run through crude distillation units, expressed as a percentage of the capacity of these units.

(3) Utilization rates are determined based on refinery capacities in effect prior to January 1, 2012.

(4) 2009 figures have been adjusted to reflect operations subsequent to the merger with Petro-Canada on August 1, 2009, so that they align with refinery utilization rates.

Total sales of refined petroleum products averaged 83,100 m^3/d in 2011, compared to 87,300 m^3/d in 2010. Gasoline sales for 2011 in Eastern Canada decreased compared with 2010, due mainly to lower demand from higher pump prices and the disposal of numerous retail sites in 2010 as mandated by the Canadian Competition Bureau as a result of the merger. There was strong demand for distillate in 2011; however, sales volumes were impacted by a month-long disruption to third-party hydrogen supply at the Edmonton refinery. Sales of lubricants products increased approximately 5% compared to 2010, led by growth in higher margin products.

Refinery utilization in Eastern North America averaged 94% in 2011, compared to 89% in 2010. Refinery utilization in 2010 at the Sarnia refinery was negatively impacted by Enbridge pipeline disruptions.

Refinery utilization in Western North America averaged 91% in 2011, compared to 95% in 2010. Refinery utilization in 2011 for Edmonton was

impacted primarily by a month-long disruption to third-party hydrogen supply

and a six-week planned maintenance event during the second quarter. Refinery utilization in 2011 for the Commerce City refinery was impacted by a five-week planned maintenance event during the second quarter.

Effective January 1, 2012, Suncor upwardly revised the nameplate capacities of the Commerce City and Montreal refineries, reflecting improvements in reliability and operations. The Commerce City refinery capacity increased from 93,000 bbls/d to 98,000 bbls/d and the Montreal refinery capacity increased from 130,000 bbls/d to 137,000 bbls/d.

Prices and Margins

Refining margins in 2011 were significantly higher than in 2010, due mainly to higher crack spreads and discounted prices for WTI-based crudes that benefited our inland refineries (Sarnia, Edmonton and Commerce City) for most of 2011. Refining margins were also higher in 2011 due to the increasing price environment for crude, whereby inventories produced during periods of lower feedstock costs were sold and replaced with inventories produced during periods of relatively higher feedstock costs.

Marketing margins for 2011 were strong in wholesale distillate channels, reflecting strong demand, and, for our lubricants operations, reflecting higher demand and increased sales of higher margin products.

Expenses and Other Factors

Operating expenses were slightly higher in 2011 than in 2010, due mainly to volume growth in wholesale channels, which resulted in higher costs for transportation and commissions, partially offset by lower share-based compensation expense. The Financing Expense and Other Income factor was positively impacted by a gain pertaining to the company's investments in marketing entities.

Planned Maintenance Events

Refining and Marketing has several smaller outages planned for 2012, but none as large as the three planned maintenance events that occurred in 2011 at the Sarnia, Edmonton and Commerce City refineries. For 2012, the company's planned maintenance events reflect crude unit maintenance at the Sarnia and Commerce City refineries and minor secondary process unit maintenance at all four refineries.

Results for 2010 compared with 2009

Refining and Marketing net earnings in 2010 were $819 million, compared to $407 million in 2009. Net earnings in 2009 included the negative impact associated with inventory acquired at fair value in the merger.

Refining and Marketing operating earnings in 2010 were $796 million, compared to $455 million in 2009, and were higher primarily as a result of the merger, which more than doubled refinery throughput capacity (from 178,000 bbls/d to 443,000 bbls/d) and increased refined product sales by approximately 60%, compared with 2009. Operating earnings were also higher due to improved operational reliability, strong distillate cracking margins and wider light/heavy and light/sour synthetic crude differentials.

Cash flow from operations in 2010 was $1.538 billion, compared to $921 million in 2009, and increased mainly due to the same factors impacting operating earnings.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

Strategy and Operational Update

The Energy Trading business continues to evaluate additional pipeline and storage agreements to support planned increases in production capacity. Until the company completes its Oil Sands growth projects, Suncor's Energy Trading business expects to optimize the capacities associated with existing arrangements.

Suncor continues to evaluate new opportunities to build its renewable energy portfolio, and has a number of potential wind power project sites in various stages of evaluation.

Financial Highlights [1]

Year ended December 31 ($ millions)	**2011**	2010	2009
Net (loss) earnings	**(331)**	(448)	104
Operating (loss) earnings [2]			
Renewable Energy	**72**	33	40
Energy Trading	**149**	64	44
Corporate	**(346)**	(842)	(529)
Group Eliminations	**(22)**	11	(93)
	(147)	(734)	(538)
Cash flow used in operations [2]	**(246)**	(984)	(653)

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See also the Non-GAAP Financial Measures Advisory section of this MD&A.

The net loss for Corporate, Energy Trading and Eliminations in 2011 was $331 million, compared to $448 million in 2010. In 2011, the Canadian dollar weakened in relation to the U.S. dollar, with the US$/Cdn$ exchange rate decreasing from 1.01 to 0.98 and resulting in an after-tax unrealized foreign exchange loss on U.S. dollar denominated long-term debt of $161 million. In 2010, the Canadian dollar strengthened in relation to the U.S. dollar, with the exchange rate increasing from 0.96 to 1.01, resulting in an after-tax unrealized foreign exchange gain on U.S. dollar denominated long-term debt of $372 million.

The operating loss for Corporate, Energy Trading and Eliminations in 2011 was $147 million, compared with an operating loss of $734 million in 2010. Operating earnings are discussed below.

Operating Earnings

Operating Earnings Reconciliation [1]

Year ended December 31 ($ millions)	**2011**	2010	2009
Net earnings (loss)	**(331)**	(448)	104
Unrealized foreign exchange loss (gain) on U.S. dollar denominated long-term debt	**161**	(372)	(798)
Impairments and write-offs	**23**	—	—
Merger and integration costs	**—**	79	151
Adjustments to provisions for assets acquired through the merger	**—**	7	—
Impact of income tax rate adjustments on deferred income taxes	**—**	—	5
Operating loss [2]	**(147)**	(734)	(538)

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Non-GAAP financial measure. The company has restated operating earnings from 2010 for the transition to IFRS and restated operating earnings for 2009 and 2010 for the removal of certain prior period operating earnings adjustments. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Renewable Energy

Year ended December 31	**2011**	2010	2009
Power generation marketed (gigawatt hours)	**245**	174	177
Ethanol production (thousands of m^3)	**381.5**	206.0	193.7

Suncor's Renewable Energy assets contributed operating earnings of $72 million in 2011, compared to $33 million in 2010, and increased primarily due to higher ethanol production and higher margins for ethanol sales. At the end of January 2011, Suncor completed the expansion of its ethanol plant in Ontario, which doubled production capacity from 200 million litres per year to 400 million litres per year.

Total power generation marketed in 2011 increased to 245 gigawatt hours from 174 gigawatt hours in 2010. In 2011, Suncor commissioned two new wind power projects – the 88-MW, 55-turbine Wintering Hills project in southern Alberta and the 20-MW, eight-turbine Kent Breeze project in southwest Ontario.

Energy Trading

Energy Trading activities contributed operating earnings of $149 million in 2011, compared to $64 million in 2010. Energy trading continued to increase operating earnings, primarily through its heavy crude trading strategies that purchase heavy crude oil in Alberta and transport it to markets with more favourable prices. The price differential between these two locations was considerably wider in 2011, consistent with the discount for WTI compared to Brent.

Corporate

Corporate had an operating loss of $346 million in 2011, compared with an operating loss of $842 million in 2010. The 2010 operating loss included after-tax claims of $243 million for the two Oil Sands Base upgrader fires paid by the company's captive insurance program. The decrease in operating loss was also due to an increase in capitalized interest (approximately $225 million more capitalized after tax) that reduced the amount of borrowing costs that were expensed, and lower share-based compensation expense, partially offset by higher DD&A due to the start of depreciation on Suncor's post-merger systems integration initiative.

In 2011, the company capitalized 85% of its borrowing costs as part of the cost of major development assets and construction projects, compared to 43% in 2010. Subsequent to the completion of transactions with Total E&P, the company resumed capitalizing interest for the Voyageur upgrader project and commenced capitalizing interest for the Fort Hills and Joslyn projects.

Group Eliminations

Group Eliminations reflects the elimination of profit on crude oil sales from Oil Sands, Syncrude and East Coast Canada to Refining and Marketing. Consolidated profits are only realized when the company determines that the refined products produced from intersegment purchases of crude feedstock have been sold to third parties. In 2011, $22 million of after-tax intersegment profit was eliminated.

Results for 2010 compared with 2009

The net loss for Corporate, Energy Trading and Eliminations for 2010 was $448 million, compared with net earnings of $104 million in 2009. In 2009, the Canadian dollar strengthened in relation to the U.S. dollar as the US$/Cdn$ exchange rate increased from 0.82 to 0.96, resulting in an after-tax unrealized foreign exchange gain on U.S. dollar denominated long-term debt of $798 million. However, results from 2009 were more significantly impacted by costs associated with the merger with Petro-Canada and resulting integration costs.

The operating loss for Corporate, Energy Trading and Eliminations for 2010 was $734 million, compared with an operating loss of $538 million in 2009. The higher operating loss in 2010 reflected the claims paid by the company's captive insurance program.

6. FOURTH QUARTER 2011 ANALYSIS

Financial and Operational Highlights

Three months ended December 31 ($ millions, except as noted)	**2011**	2010
Net earnings		
Oil Sands	**790**	484
Exploration and Production	**284**	386
Refining and Marketing	**307**	367
Corporate, Energy Trading and Eliminations	**46**	49
Total	**1 427**	1 286
Operating earnings (loss) [1]		
Oil Sands	**835**	345
Exploration and Production	**372**	275
Refining and Marketing	**307**	366
Corporate, Energy Trading and Eliminations	**(87)**	(178)
Total	**1 427**	808
Cash flow from (used in) operations [1]		
Oil Sands	**1 417**	796
Exploration and Production	**780**	948
Refining and Marketing	**534**	610
Corporate, Energy Trading and Eliminations	**(81)**	(222)
Total	**2 650**	2 132
Production volumes (mboe/d)		
Oil Sands	**356.8**	363.8
Exploration and Production	**219.7**	261.8
Total	**576.5**	625.6

(1) Non-GAAP financial measures. Operating earnings and cash flow from operations are reconciled below. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Segment Analysis

Oil Sands

Oil Sands net earnings for the fourth quarter of 2011 were $790 million, compared to $484 million in the fourth quarter of 2010. Operating earnings for the fourth quarter of 2011 were $835 million, compared to $345 million for the fourth quarter of 2010. Cash flow from operations from the fourth quarter of 2011 was $1.417 billion, compared to $796 million in the fourth quarter of 2010. These increases were due primarily to higher margins driven by higher price realizations and improved production and sales of higher margin sweet SCO and diesel, partially offset by higher In Situ operating expenses that were largely associated with the Firebag Stage 3 expansion and higher mining costs required to move more tonnes of ore to maintain bitumen supply while working through the area of lower bitumen ore grade and to remove more tonnes of overburden.

Oil Sands production (excluding Syncrude) increased slightly to 326.5 mbbls/d from 325.9 mbbls/d, reflecting higher bitumen output from Firebag and an increase in bitumen ore tonnes mined. In Situ bitumen production increased to 101.4 mbbls/d from 85.8 mbbls/d, due mainly to the ramp up of production from the first well pad for the Firebag Stage 3 expansion and recently completed infill wells on existing Firebag well pads. For Oil Sands Ventures, Suncor's share of Syncrude production decreased to 30.3 mbbls/d from 37.9 mbbls/d due primarily to operational issues with a hydrogen plant and a coker unit.

Exploration and Production

Exploration and Production net earnings for the fourth quarter of 2011 were $284 million, compared to $386 million in the fourth quarter of 2010. Net earnings in the fourth quarter of 2011 included net after-tax impairment charges of $57 million taken primarily against certain North America Onshore properties due to decreasing prices for natural gas. Net earnings in the fourth quarter of 2010 were positively impacted by after-tax adjustments of $186 million for the redetermination of Suncor's working interest in Terra Nova, but negatively impacted by after-tax impairments and write-offs of $96 million also taken primarily against certain North America Onshore properties due to decreasing prices for natural gas.

Exploration and Production operating earnings for the fourth quarter of 2011 were $372 million, compared to $275 million in the fourth quarter of 2010, and increased primarily due to higher average price realizations, partially offset by the impact of lower production volumes, the provision against accounts receivable related to Syria, and higher royalties that reflected a higher percentage of unsold production from Libya.

Production volumes were 219.7 mboe/d in the fourth quarter of 2011, compared to 261.8 mboe/d in the fourth quarter of 2010. The decrease in production volumes was due mainly to the disposal of non-core assets and lower output from Libya during the restart of production following the lifting of sanctions.

Cash flow from operations was $780 million in the fourth quarter of 2011, which was lower than $948 million for the fourth quarter of 2010, due mainly to 2010 including the gain for the redetermination of Suncor's working interest in Terra Nova.

Refining and Marketing

Refining and Marketing net and operating earnings for the fourth quarter of 2011 were $307 million, compared with net earnings of $367 million and operating earnings of $366 million in the fourth quarter of 2010. Cash flow from operations was $534 million in the fourth quarter of 2011, compared to $610 million in the fourth quarter of 2010.

Sales volumes decreased to 81,600 m^3/d from 89,200 m^3/d. This decrease was primarily due to lower crude throughput at the Edmonton refinery due to a month-long disruption in third-party hydrogen supply. Sales volumes were also lower due to lower demand for heating oil through the wholesale channel in Eastern Canada, due mainly to warmer weather.

Corporate, Energy Trading and Eliminations

Net earnings for this group in the fourth quarter of 2011 were $46 million, compared with net earnings of $49 million in the fourth quarter of 2010. In the fourth quarter of 2011, the Canadian dollar strengthened in relation to the U.S. dollar, with the US$/Cdn$ exchange rate increasing from 0.95 to 0.98 and resulting in an after-tax unrealized foreign exchange gain on U.S. dollar denominated long-term debt of $156 million. In the fourth quarter of 2010, the Canadian dollar strengthened in relation to the U.S. dollar as the exchange rate increased from 0.97 to 1.01, resulting in an after-tax unrealized foreign exchange gain on U.S. dollar denominated long-term debt of $252 million.

The operating loss for this group in the fourth quarter of 2011 was $87 million, compared with an operating loss of $178 million in the fourth quarter of 2010. The decrease in operating loss was due mainly to an increase in capitalized interest related to more major projects being under construction. This decrease was partially offset by higher Renewable Energy earnings that reflected higher ethanol production from the plant expansion, higher Energy Trading earnings that reflected price differences between Alberta and U.S. Gulf Coast markets for heavy crude oil, and lower share-based compensation expense.

Operating Earnings (1)

Three months ended December 31	Oil Sands		Exploration and Production		Refining and Marketing		Corporate Energy Trading and Eliminations		Total	
($ millions)	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Net earnings as reported	**790**	484	**284**	386	**307**	367	**46**	49	**1 427**	1 286
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**(156)**	(252)	**(156)**	(252)
Impairments and write-offs	**35**	2	**57**	96	**—**	—	**23**	—	**115**	98
Loss (gain) on significant disposals	**10**	—	**—**	(21)	**—**	—	**—**	—	**10**	(21)
Adjustments to provisions for assets acquired through the merger	**—**	—	**31**	—	**—**	(1)	**—**	7	**31**	6
Change in fair value of commodity derivatives used for risk management, net of realizations	**—**	(48)	**—**	—	**—**	—	**—**	—	**—**	(48)
Redetermination of working interest in Terra Nova	**—**	—	**—**	(186)	**—**	—	**—**	—	**—**	(186)
Modification of the bitumen valuation methodology	**—**	(93)	**—**	—	**—**	—	**—**	—	**—**	(93)
Merger and integration costs	**—**	—	**—**	—	**—**	—	**—**	18	**—**	18
Operating earnings (loss)	**835**	345	**372**	275	**307**	366	**(87)**	(178)	**1 427**	808

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Cash flow from Operations [1]

Three months ended December 31 ($ millions)	Oil Sands		Exploration and Production		Refining and Marketing		Corporate Energy Trading and Eliminations		Total	
	2011	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Net earnings	**790**	484	**284**	386	**307**	367	**46**	49	**1 427**	1 286
Adjustments for:										
Depreciation, depletion, amortization and impairment	**392**	308	**474**	530	**118**	114	**39**	26	**1 023**	978
Deferred income taxes	**270**	140	**(30)**	11	**92**	134	**(10)**	(64)	**322**	221
Accretion of liabilities	**18**	52	**16**	42	**1**	—	**—**	—	**35**	94
Unrealized foreign exchange gain on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**(179)**	(290)	**(179)**	(290)
Change in fair value of derivative contracts	**—**	(66)	**—**	—	**17**	—	**34**	34	**51**	(32)
Loss (gain) on disposal of assets	**16**	3	**(9)**	(26)	**(5)**	(11)	**—**	38	**2**	4
Share-based compensation	**31**	11	**8**	29	**19**	27	**21**	39	**79**	106
Exploration expense	**—**	—	**—**	10	**—**	—	**—**	—	**—**	10
Other	**(100)**	(136)	**37**	(34)	**(15)**	(21)	**(32)**	(54)	**(110)**	(245)
Cash flow from (used in) operations	**1 417**	796	**780**	948	**534**	610	**(81)**	(222)	**2 650**	2 132
(Increase) decrease in non-cash working capital	**(47)**	(186)	**9**	(74)	**587**	(8)	**(396)**	(120)	**153**	(388)
Cash flow provided by (used in) operating activities	**1 370**	610	**789**	874	**1 121**	602	**(477)**	(342)	**2 803**	1 744

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

7. QUARTERLY FINANCIAL DATA

Financial and Operating Highlights

Three months ended ($ millions, unless otherwise noted)	**Dec 31 2011**	Sept 30 2011	June 30 2011	Mar 31 2011	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010
Total production (mboe/d)	**576.5**	546.0	460.0	601.3	625.6	635.5	633.9	564.6
Oil Sands	**356.8**	362.5	277.2	360.6	363.8	338.3	334.4	234.6
Exploration and Production	**219.7**	183.5	182.8	240.7	261.8	297.2	299.5	330.0
Revenues and other income								
Operating revenues, net of royalties	**10 077**	10 494	9 510	9 256	8 982	7 717	8 174	7 130
Other income [1]	**60**	184	77	132	358	(45)	287	1
	10 137	10 678	9 587	9 388	9 340	7 672	8 461	7 131
Net earnings	**1 427**	1 287	562	1 028	1 286	1 224	540	779
per common share (dollars)								
Basic	**0.91**	0.82	0.36	0.65	0.82	0.78	0.35	0.50
Diluted	**0.91**	0.76	0.31	0.65	0.82	0.78	0.34	0.46
Operating earnings [2]	**1 427**	1 789	980	1 478	808	617	839	370
per common share – basic [2] (dollars)	**0.91**	1.14	0.62	0.94	0.52	0.39	0.54	0.24
Cash flow from operations [2]	**2 650**	2 721	1 982	2 393	2 132	1 630	1 770	1 124
per common share – basic [2] (dollars)	**1.69**	1.73	1.26	1.52	1.36	1.04	1.13	0.72
ROCE [2][3] (%) for the twelve months ended	**13.8**	13.4	11.1	12.5	11.4	9.3	7.9	4.8
Common share information								
Dividend per common share (dollars)	**0.11**	0.11	0.11	0.10	0.10	0.10	0.10	0.10
Share price at the end of trading								
Toronto Stock Exchange (Cdn$)	**29.38**	26.76	37.80	43.48	38.28	33.50	31.33	33.03
New York Stock Exchange (US$)	**28.83**	25.44	39.10	44.84	38.29	32.55	29.44	32.54

(1) In 2011, the company completed a review of its energy supply and trading activities and determined that the nature and purpose of transactions previously presented on a gross basis in Energy Supply and Trading Income and Expenses in the Consolidated Statements of Comprehensive Income have evolved such that they are more appropriately reflected through net presentation. See the Accounting Policies and Critical Accounting Estimates section of this MD&A.

(2) Non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(3) Excludes capitalized costs related to major projects in progress.

Business Environment

Three months ended (average for the period ended, except as noted)		**Dec 31 2011**	Sept 30 2011	June 30 2011	Mar 31 2011	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010
WTI crude oil at Cushing	US$/bbl	**94.05**	89.75	102.55	94.10	85.20	76.20	78.05	78.70
Dated Brent crude oil at Sullom Voe	US$/bbl	**109.00**	113.40	117.30	104.95	86.50	76.85	78.30	76.25
Dated Brent/Maya FOB price differential	US$/bbl	**5.55**	14.80	14.05	15.65	10.85	9.35	10.45	6.50
Canadian 0.3% par crude oil at Edmonton	Cdn$/bbl	**98.20**	92.50	103.85	88.40	80.70	74.90	75.50	80.95
Light/heavy crude oil differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**10.45**	17.65	17.65	22.85	18.10	15.65	14.00	9.05
Condensate at Edmonton	US$/bbl	**108.70**	101.65	112.40	98.35	85.70	74.50	82.70	84.65
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**3.40**	3.70	3.75	3.80	3.60	3.50	3.85	5.35
New York Harbor 3-2-1 crack [1]	US$/bbl	**22.80**	36.45	29.25	19.40	12.20	9.60	12.50	7.95
Chicago 3-2-1 crack [1]	US$/bbl	**19.20**	33.30	29.70	16.45	9.20	10.15	11.05	5.65
Portland 3-2-1 crack [1]	US$/bbl	**26.45**	36.50	29.35	21.40	13.50	16.60	15.50	8.55
Gulf Coast 3-2-1 crack [1]	US$/bbl	**20.40**	33.10	27.30	18.50	8.50	8.60	11.20	7.70
Exchange rate	US$/Cdn$	**0.98**	1.02	1.03	1.01	0.99	0.96	0.97	0.96
Exchange rate (end of period)	US$/Cdn$	**0.98**	0.95	1.04	1.03	1.01	0.97	0.94	0.98

(1) 3-2-1 crack spreads are indicators of the refining margin generated by converting three barrels of WTI into two barrels of gasoline and one barrel of diesel. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

Trends in Suncor's quarterly earnings results and cash flow from operations are driven primarily by production volumes, which can be significantly impacted by major planned maintenance events, such as the one that occurred for Oil Sands Base operations at Upgrader 2 in the second quarter of 2011, and by changes in commodity prices, refining crack spreads and foreign exchange rates, which are summarized above and discussed in the Consolidated Financial Information – Business Environment section of this MD&A.

Over the last eight quarters, Suncor's results were impacted by several important events:

- Results in the first quarter of 2010 were significantly impacted by two upgrader fires that decreased Oil Sands production.

- As part of its strategic business alignment subsequent to the merger with Petro-Canada, Suncor divested a number of non-core assets in its Exploration and Production segment throughout 2010 and 2011. Decreases in production volumes in 2011 are due in part to the disposition of these assets. In addition, the resulting gains and losses on disposition of these assets had one-time impacts on net earnings in the quarters in which they occurred.

Net earnings over the last eight quarters were also affected by other one-time adjustments, including:

- The fourth quarter of 2011 included net after-tax impairments and write-offs of $115 million, taken primarily against North America Onshore assets due to decreasing natural gas prices and against crude inventories due to third-party pipeline adjustments.

- The second quarter of 2011 included impairment charges of $514 million (net of income taxes of $nil, $11 million was later reversed in 2011) against assets in Libya that were associated with the shut-in of production due to political unrest, which also decreased production volumes for 2011.

- The first quarter of 2011 included a $442 million adjustment to deferred income tax expense related to an increase in U.K. tax rates on oil and gas profits in the North Sea.

- The fourth quarter of 2010 included an after-tax gain of $186 million for the redetermination of working interests in the Terra Nova oilfield and an after-tax royalty recovery of $93 million with respect to the modification of the BVM.

- The second quarter of 2010 included an after-tax write-off of $141 million for Oil Sands Base assets that were being used in the development of an alternative extraction process that was discontinued.

8. CAPITAL INVESTMENT UPDATE

The Capital Investment Update section contains forward-looking information. See the Advisory – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Capital and Exploration Expenditures

Year ended December 31 ($ millions)	**2011**	2010	2009
Oil Sands	**5 100**	3 709	2 831
Exploration and Production	**874**	1 274	986
Refining and Marketing	**633**	667	380
Corporate, Energy Trading and Eliminations	**243**	360	70
Total capital and exploration expenditures	**6 850**	6 010	4 267
Capitalized interest (included in above figures)	**559**	301	136

Capital and exploration expenditures do not include the purchase of the company's interest in the Joslyn project, which is shown as an acquisition in the audited Consolidated Statements of Cash Flows.

Oil Sands

Oil Sands capital and exploration expenditures were $5.100 billion in 2011. Growth spending in 2011 focused primarily on the following significant projects:

- Capital expenditures for Firebag Stage 3 were $570 million in 2011, bringing total project expenditures to $4.370 billion. In 2011, the company completed construction of all well pads and the central processing facilities. The first well pad began bitumen production in July. The second and third well pads are being steamed, with initial bitumen production expected in the first half of 2012. Peak production from Firebag Stage 3 is anticipated in the next 18 to 24 months.

- Capital expenditures for Firebag Stage 4 were $670 million in 2011, bringing total project expenditures to $1.2 billion. Construction continued on infrastructure, central processing facilities, cogeneration units and the two well pads. Some infrastructure required for Stage 4 was completed as part of Stage 3.

- The company completed construction of the hydrogen plant portion of the MNU, which produced hydrogen in December 2011 and January 2012 before being taken off-line for minor modifications prior to further commissioning. The company expects to have the hydrogen plant operating at design rates by the middle of 2012.

- The company started mining ore from the NSE late in 2011, and operations are expected to ramp up over the next twelve months. The NSE project develops a new mining resource, and is expected to improve productivity of overall mining operations and decrease operating costs by alleviating congestion in the Millennium mining area and reducing average haul distances. The company has applied for regulatory approval to increase the NSE project area. If approved, the expanded area is expected to provide additional recoverable bitumen.

In 2011, the company spent $622 million on the implementation its TRO $_{TM}$ infrastructure project and an additional $110 million on tailings drying facilities. The infrastructure project included the construction of pumping and pipeline facilities for tailings and water transfers across Oil Sands Base mining operations.

Other significant capital expenditures for 2011 focused on the planned maintenance event at Upgrader 2, the acquisition of additional land adjacent to one of our oil sands mining properties, preparation of the NSE, major refurbishments and welding of coker units, the mine train replacement project for Syncrude and the restart of our Fort Hills and Voyageur upgrader projects.

Exploration and Production

Exploration and Production capital and exploration expenditures were $874 million in 2011.

For East Coast Canada operations, capital expenditures focused on the replacement of a flow line for partial H_2S remediation and the drilling and completion of a new production well at Terra Nova, the continued development of the HSEU, the completion (including initial production) of the first of two pilot wells in the West White Rose field that is part of the White Rose Extensions, an exploratory well for the Ballicatters discovery, and front-end engineering and project development activities for Hebron.

For International operations in the North Sea, capital expenditures focused on the commissioning of the fourth platform at Buzzard, installed to remove H_2S in the oil production from some segments of the field, pre-sanction activity and preliminary design for Golden Eagle, which received regulatory and partner approval during the year, exploratory drilling at the Butch prospect offshore Norway where a discovery was made, and the acquisition of new exploration licences offshore Norway (four operated and

one non-operated) and the U.K. (one operated and one non-operated).

For International operations in Libya and Syria, capital expenditures were limited in 2011. Operations were suspended in Libya throughout much of 2011. The company completed one oil production well in Syria before suspending the drilling program mid-year because of unrest, and prior to the introduction of sanctions, which resulted in Suncor suspending all operations in Syria in December 2011.

For North America Onshore operations, capital expenditures focused on the development of production wells in the Wilson Creek and Ferrier areas of the Cardium oil formation, and exploration in the Kobes area of the Montney shale gas formation.

Refining and Marketing

Refining and Marketing spent $633 million on capital expenditures in 2011. Expenditures focused on a variety of projects, including one to reduce benzene content in gasoline production at the Commerce City refinery, which is expected to be completed by the second quarter of 2012.

Corporate, Energy Trading and Eliminations

In 2011, the Renewable Energy business completed the construction and commissioning of the Wintering Hills and Kent Breeze wind projects, and the expansion of the ethanol plant.

Corporate capital expenditures focused on Suncor's initiative to integrate pre-merger information systems onto one common platform.

Significant Growth Projects Update

	Description	Cost Estimate ($ millions)	Project Spend to Date ($ millions)	Target Completion	Estimated % Complete Engineering	Estimated % Complete Construction
Operated						
Firebag Stage 3 expansion	62.5 mbbls/d bitumen	4 400	4 370	Q1 2012	100	100
Firebag Stage 4 expansion	62.5 mbbls/d bitumen	2 000 (±10%)	1 189	Q1 2013	99	60
Non-operated [1]						
Golden Eagle	70 mboe/d (gross)	880 (±10%)	64	Q4 2014		

(1) Cost estimate as per the operator of Golden Eagle, Nexen Petroleum U.K. Limited. Estimated completion percentages not provided for non-operated projects.

The table above provides a review and update at December 31, 2011 of major growth projects that have been sanctioned for development by the company. Other growth projects, such as the Fort Hills and Joslyn oil sands mining projects and the Voyageur upgrader, have not yet received a final investment decision by the company's Board of Directors. These projects are discussed under the Other Capital Projects section below.

The Firebag Stage 3 expansion is nearly complete. The company expects to commission the cogeneration units in the first quarter of 2012. The ramp up of production from the Stage 3 expansion is continuing, and the company expects to reach peak production levels during the second half of 2013. Stage 3 facilities have a planned bitumen capacity of 62,500 bbls/d.

The primary focus for growth capital in 2012 will be the Firebag Stage 4 expansion. In 2012, the company anticipates that construction will continue on the two well pads, central processing facilities and cogeneration units, and plans to initiate steaming of the first well pad in the fourth quarter of 2012, so that first oil can be achieved late in the first quarter of 2013. Stage 4 facilities also have a planned bitumen capacity of 62,500 bbls/d.

The field development plan for the Golden Eagle Area Development in the U.K. portion of the North Sea includes stand-alone facilities designed for 70,000 boe/d of gross production. Activity in 2012 for the development of Golden Eagle is anticipated to focus on the construction and fabrication of the topsides and jacket for the fixed gravity base structure (GBS).

There are risks associated with project cost estimates provided by Suncor. Accordingly, actual costs can vary from estimates, and these differences can be material. Some of these risks are described in the Risk Factors section of this MD&A under the heading Project Execution and Partner Risk.

Other Capital Projects

Suncor also anticipates 2012 capital expenditures focused on the following projects and initiatives:

Oil Sands Base

Suncor will continue implementing its TRO$_{TM}$ tailings reclamation technology across Oil Sands Base operations. The infrastructure project is on schedule to be completed by the fourth quarter of 2012. The company also plans to construct more tailings drying facilities.

Other capital spending for Oil Sands Base is expected to focus on sustaining capital investments, which maintain production capacities at existing facilities, and include costs for planned maintenance events, catalyst, truck and shovel replacement, and the replacements for utilities, roads and other facilities.

In Situ

Capital spending is expected to focus on continuing to build well pads at Firebag and MacKay River and continuing the infill well program at Firebag. This activity, separate from the Firebag Stage 3 and Stage 4 expansions, maintains an inventory of future bitumen supply for central processing facilities as older wells experience natural production declines.

Oil Sands Ventures

In 2013, the company plans to present for sanctioning the budget for the combined development of the Voyageur upgrader, Fort Hills and Joslyn projects to Suncor's Board of Directors. For 2012, Suncor anticipates capital expenditures for:

- The Voyageur upgrader project will focus primarily on validating project scope, developing the project execution plan, engineering and progressing site preparation.
- Fort Hills will focus primarily on progressing design basis memorandum engineering and site preparation, and procuring long-lead items.
- Joslyn will focus on further design work, progressing front-end engineering and site preparation.

Capital expenditures in 2012 for Syncrude are expected to focus on the mine train replacement for the Mildred Lake mine, the mine train relocation at the Aurora mine and sustaining maintenance initiatives.

Exploration and Production

The company anticipates that the second pilot well for water injection support in the West White Rose field of the White Rose Extensions will be completed in the second quarter of 2012. Results from the pilot project, along with other ongoing evaluations, will help define the scope of future development for the West White Rose field.

The Hebron project development plan application was submitted to the Canada Newfoundland and Labrador Offshore Petroleum Board on April 15, 2011. In 2012, the company expects front-end engineering to be finalized, detailed design to commence and major construction contracts to be awarded. The company expects a regulatory approval decision in 2012, followed by a sanction decision by joint venture owners.

Other capital expenditures for East Coast Canada operations are expected to focus on development drilling for Terra Nova, Hibernia and White Rose, the water injection swivel replacement for the FPSO and H_2S remediation activity at Terra Nova, the propulsion system maintenance for the White Rose FPSO, and the procurement of subsea equipment for the development of the HSEU.

The company has secured a rig to drill its third appraisal well for the Beta discovery in the Norway portion of the North Sea under the PL375 licence. Drilling is expected to commence in the first quarter of 2012. Suncor has secured a rig to drill an exploration well for the Romeo joint venture prospect in the U.K. portion of the North Sea and also expects to participate in a non-operated exploration well in the Norway portion of the North Sea. The company expects the drilling of both of these wells will commence in 2012.

For North America Onshore operations, the company plans to continue exploration in the Cardium oil formation and Montney shale gas formation.

9. FINANCIAL CONDITION AND LIQUIDITY

Indicators

At December 31 ($ millions, except as noted)	2011	2010
Working capital [1]	**786**	1 148
Short-term debt	**763**	1 984
Current portion of long-term debt	**12**	518
Long-term debt	**10 004**	9 829
Total debt	**10 779**	12 331
Less: Cash and cash equivalents	**3 803**	1 077
Net debt	**6 976**	11 254
Shareholders' equity	**38 600**	35 192
Total debt plus shareholders' equity	**49 379**	47 523
Total debt to total debt plus shareholders' equity (%)	**22**	26

(1) Current assets less current liabilities, excluding cash and cash equivalents, short-term debt, current portion of long-term debt, and current assets and liabilities associated with assets held for sale.

Twelve months ended December 31	2011	2010
Return on Capital Employed (%) [1]		
Excluding major projects in progress	**13.8**	11.4
Including major projects in progress	**10.1**	8.2
Net debt to cash flow from operations [2] (times)	**0.7**	1.7
Interest coverage on long-term debt (times)		
Earnings basis [3]	**10.7**	8.8
Cash flow from operations basis [2][4]	**16.4**	11.7

(1) Non-GAAP financial measure. The calculations for ROCE are detailed in the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) Cash flow from operations and metrics that use cash flow from operations are non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(3) Net earnings plus income taxes and interest expense, divided by the sum of interest expense and capitalized interest.

(4) Cash flow from operations plus current income taxes and interest expense, divided by the sum of interest expense and capitalized interest.

Capital Resources

Suncor's capital resources consist primarily of cash flow from operations, cash and cash equivalents, and available lines of credit. Suncor's management believes the company will have the capital resources to fund its planned 2012 capital spending program of $7.5 billion and meet current and long-term working capital requirements. The company's cash flow from operations depends on a number of factors, including commodity prices, production and sales volumes, refining and marketing margins, operating expenses, taxes, royalties and foreign exchange rates. If additional capital is required, Suncor's management believes adequate additional financing will be available in debt capital markets at commercial terms and rates.

For the year ended December 31, 2011, the company's net debt to cash flow from operations measure was 0.7 times, which met management's target of less than 2.0 times.

In 2011, cash and cash equivalents increased $2.726 billion to $3.803 billion, due mainly to higher cash flow from operations and net proceeds from transactions with Total E&P. These increases were partially offset by the company reducing its short-term debt by $1.221 billion, repaying $500 million of Medium Term Notes that came due in 2011, higher capital and exploration expenditures, the return of $500 million to shareholders through the share repurchase plan, and a 10% increase to the company's quarterly dividend (to $0.11 per common share) declared in the second quarter of 2011.

Unutilized lines of credit at December 31, 2011 were approximately $4.428 billion, compared to $5.289 billion at December 31, 2010.

A summary of available and utilized credit facilities is as follows:

($ millions)

Facility that is fully revolving for a period of one year and expires in 2013	2 000
Facilities that are fully revolving for a period of four years and expire in 2013	203
Facility that is fully revolving for a period of four years and expires in 2016	3 000
Facilities that can be terminated at any time at the option of the lenders	612
Total available credit facilities	5 815
Less:	
Credit facilities supporting outstanding commercial paper	761
Credit facilities supporting standby letters of credit	626
Total unutilized credit facilities	4 428

Financing Activities

Management of debt levels continues to be a priority for Suncor given the company's long-term growth plans. Suncor's management believes a phased and flexible approach to existing and future growth projects should assist Suncor in maintaining its ability to manage project costs and debt levels.

At December 31, 2011, Suncor's net debt was $6.976 billion, compared to $11.254 billion at December 31, 2010.

Change in Net Debt

($ millions)

Net debt – December 31, 2010	11 254
Decrease in net debt	(4 278)
Net debt – December 31, 2011	6 976
Decrease in net debt	
Cash flow from operations	9 746
Capital and exploration expenditures and other investments	(6 856)
Proceeds from divestitures, net of costs for acquisitions	2 232
Dividends less proceeds from exercise of share options	(451)
Repurchase of common shares	(500)
Change in non-cash working capital and other	268
Foreign exchange on cash, long-term debt and other balances	(161)
	4 278

The company expects to maintain access to short-term commercial paper borrowing at competitive interest rates by keeping short-term debt at existing levels. During 2011, the company transitioned the majority of its short-term debt to U.S. dollar denominated commercial paper.

The company has invested excess cash in short-term financial instruments that are presented as cash and cash equivalents. The objectives of the company's short-term investment portfolio are to ensure the preservation of capital, maintain adequate liquidity to meet Suncor's cash flow requirements and deliver competitive returns consistent with the quality and diversification of investments within acceptable risk parameters. The maximum weighted average term to maturity of the short-term investment portfolio is expected not to exceed six months, and all investments are expected to be with counterparties with investment grade debt ratings. As at December 31, 2011, the weighted average term to maturity of the short-term investment portfolio was 31 days. In 2011, the company earned approximately $21 million of interest income on this portfolio.

Suncor's interest on debt (before capitalized interest) in 2011 was $661 million, compared to $704 million in 2010. The decrease in interest reflects the decrease in short-term debt and the repayment of the Medium Term Notes. Fixed-to-floating interest rate swaps on the company's long-term debt in place at December 31, 2010 matured during the year, coinciding with the repayment of the Medium Term Notes.

The company obtained regulatory approval for a Normal Course Issuer Bid (NCIB) with the Toronto Stock Exchange authorizing the purchase for cancellation of up to $500 million of its common shares. The NCIB was announced on August 20, 2011 and began on September 6, 2011. The purchase of $500 million of the company's common shares was completed by December 31, 2011. Pursuant to the NCIB, the company repurchased 17,128,065 shares at an average price of $29.19 per share in 2011. All common shares acquired under the NCIB have been cancelled.

Suncor is subject to financial and operating covenants related to its public market and bank debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations. The company is in compliance with its financial covenant that requires total debt to not exceed 60% of its total debt plus shareholders' equity. At December 31, 2011, total debt to total debt plus shareholders' equity was 22% (December 31, 2010 – 26%). The company is also currently in compliance with all operating covenants.

Credit 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 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 company's long-term senior debt ratings are:

Long-term Senior Debt	Rating	Long-term Outlook
Standard & Poor's	BBB+	Stable
Dominion Bond Rating Service	A (low)	Stable
Moody's Investors Service	Baa2	Positive

The company's commercial paper ratings are:

Commercial Paper	Cdn$ Rating	US$ Rating
Standard & Poor's	A-1 (low)	A-2
Dominion Bond Rating Service	R-1 (low)	not rated
Moody's Investors Service	not rated	P-2

In 2011, Moody's upgraded its long-term outlook for senior debt from stable to positive, and Suncor initiated access to the U.S. market for U.S. dollar commercial paper. Otherwise, these credit ratings are unchanged from December 31, 2010.

Outstanding Shares

December 31, 2011 (thousands)	
Common shares	1 558 636
Common share options – exercisable and non-exercisable	59 178
Common share options – exercisable	39 482

As at February 17, 2012, the total number of common shares outstanding was 1,561,658,318 and the total number of exercisable and non-exercisable common share options outstanding was 60,712,741. Once exercisable, each outstanding common share option is convertible into one common share.

Contractual Obligations, Commitments, Guarantees, and Off-Balance Sheet Arrangements

In the normal course of business, the company is obligated to make future payments, including contractual obligations and non-cancellable commitments.

		Payments Due by Period			
($ millions)	Total	2012	2013 to 2014	2015 to 2016	Thereafter
Fixed- and revolving-term debt [1]	10 287	762	725	—	8 800
Interest payments on fixed-term debt	10 607	596	1 181	1 129	7 701
Finance lease payments	1 026	53	106	109	758
Decommissioning and restoration costs [2]	7 275	426	887	309	5 653
Operating lease agreements, pipeline capacity and energy services commitments	13 633	1 080	2 088	1 680	8 785
Exploration work commitments	608	287	286	35	—
Other long-term obligations [3]	691	335	320	36	—
Total	44 127	3 539	5 593	3 298	31 697

(1) Includes debt that is redeemable at Suncor's option.

(2) Represents the undiscounted amount of obligations associated with land and tailings reclamation and site restoration and decommissioning costs.

(3) Includes the Libya ESPA signature bonus and Fort Hills purchase obligations. See the Other Long-Term Liabilities note to the 2011 audited Consolidated Financial Statements.

In addition to the enforceable and legally binding obligations quantified in the table presented above, Suncor has other obligations for goods and services that were entered into in the normal course of business, which may terminate on short notice, including commitments for the purchase of commodities for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase.

The company does not believe it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial condition or financial performance, including liquidity and capital resources.

Financial Instruments

Suncor periodically enters into derivative contracts such as forwards, futures, swaps, options and costless collars. We use these derivative contracts to hedge risks related to purchases and sales of commodities, to manage exposure to interest rates and to hedge risks specific to individual transactions. Gains or losses on the revaluation and settlement of derivative contracts used for these risk management activities are recorded as Other Income in the Consolidated Statements of Comprehensive Income. For the year ended December 31, 2011, the pre-tax earnings impact for risk management activities was a loss of $22 million (2010 – pre-tax gain of $89 million).

The company's Energy Trading business uses crude oil, natural gas, refined product and other derivative contracts to generate net earnings, recorded as Other Income. For the year ended December 31, 2011, the pre-tax earnings impact for Energy Trading activities was $301 million (2010 – pre-tax earnings of $106 million).

Year ended December 31 ($ millions)	**2011**	2010
Fair value of contracts at beginning of period	**(74)**	(359)
Fair value of contracts realized during the period	**(239)**	90
Change in fair value during the period	**279**	195
Fair value of derivative contracts at end of period	**(34)**	(74)

During 2011, interest rate swaps classified as fair value hedges relating to $200 million of fixed-rate debt expired. At December 31, 2010, the fair value of the interest rate swaps was an $8 million asset. Suncor is not applying hedge accounting to any derivative contracts as at December 31, 2011.

The fair value of derivatives pertaining to risk management and Energy Trading activities are recorded in the Consolidated Balance Sheets as follows:

Fair value of derivative contracts at December 31 ($ millions)	**2011**	2010
Accounts receivable	**37**	27
Accounts payable	**(71)**	(93)
	(34)	(66)

Risks Associated with Derivative Financial Instruments

Suncor may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to fulfil their obligations under these contracts. The company minimizes this risk by entering into agreements with investment grade counterparties. Risk is also minimized through regular management review of the potential exposure to and credit ratings of such counterparties. Suncor's exposure is limited to those counterparties holding derivative contracts with net positive fair values at a reporting date.

Suncor's risk management activities are subject to periodic reviews by management to determine appropriate hedging requirements based on the company's tolerance for exposure to market volatility, as well as the need for stable cash flow to finance future growth. Energy Trading activities are governed by a separate risk management group that reviews and monitors practices and policies and provides independent verification and valuation of these activities.

For further details on our derivative financial instruments, including assumptions made in the calculation of fair value, a sensitivity analysis of the effect of changes in commodity prices on our derivative financial instruments, and additional discussion of exposure to risks and mitigation activities, see the Financial Instruments and Risk Management note in our 2011 audited Consolidated Financial Statements.

Canadian Federal Budget Proposal

On December 15, 2011, Bill C-13 received Royal Assent and is considered enacted under IFRS. This new legislation includes the limitation of deferral opportunities for corporate partnerships, the change in the future treatment of oil sands lease purchases to Canadian oil and gas property expense from Canadian development expense, and the change in future treatment of pre-production development expenses for oil sands mines to Canadian development expense from Canadian exploration expense.

The company has completed an assessment of the new legislation and expects that, in future years, it will decrease cash flow from operations by accelerating the payment of cash income taxes, but will not have a significant impact on net earnings.

10. ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

Changes in Accounting Policies

Suncor's significant accounting policies are described in note 3 to the December 31, 2011 audited Consolidated Financial Statements.

Adoption of IFRS

Effective January 1, 2011, the company began reporting under IFRS. The accounting policies referenced above have been applied in preparing the financial results for the years ended December 31, 2011 and 2010, and the company's opening balance sheet as at January 1, 2010. Detailed reconciliations of amounts reported under Previous GAAP to those presented in this MD&A are provided in the First-Time Adoption of IFRS note to the December 31, 2011 audited Consolidated Financial Statements.

The following table provides a summary reconciliation of consolidated net earnings reported under Previous GAAP to that reported under IFRS:

Year ended December 31, 2010 ($ millions)

Net earnings, as reported under Previous GAAP	3 571
Adjustments to net earnings:	
Depreciation, depletion, amortization and impairment	274
Gain on disposal of assets	54
Other	17
Provision for deferred income taxes	(87)
Net earnings, as reported under IFRS	3 829

The transition to IFRS included adjustments of $1.632 billion that decreased the carrying amount of Suncor's property, plant and equipment as at January 1, 2010. Suncor applied an IFRS exemption that permitted it to revalue the amount of decommissioning and restoration costs included in the carrying value of the related assets. Suncor also applied an IFRS exemption that permitted it to record certain assets at fair value less costs to sell on the date of transition. The increase in net earnings for 2010 under IFRS compared to Previous GAAP is primarily a result of applying these exemptions to decrease the company's carrying value of property, plant and equipment, and consequently decrease subsequent depreciation of those assets and increase any gains or decrease any losses on the disposal of those assets.

The transition to IFRS also required that the company adopt accounting policies that are different to those previously reported. Changes to accounting policies that may have a significant impact on the company's net earnings or presentation of net earnings include:

- Impairment of assets – Under Previous GAAP, an asset was not impaired if estimates of its recoverable amount using undiscounted expected future cash flows exceeded its net carrying value. Under IFRS, discounted cash flows must form the estimate of recoverable amount, essentially making it more likely that asset impairments will occur. For its 2010 net earnings under Previous GAAP, the company had recorded a pre-tax impairment charge of $220 million that would have been required earlier under IFRS because of this difference in accounting policy. Under IFRS, this impairment was reflected in the opening balance sheet as at January 1, 2010.

- Classification of discontinued operations – Under Previous GAAP, most of the company's 2010 asset dispositions met the definition of discontinued operations, whereas under IFRS only an immaterial amount of the 2010 dispositions met the IFRS definition of discontinued operations. As a result, the company has restated amounts previously reported and is not presenting any discontinued operations for 2010 comparative figures.

Energy Supply and Trading Activities

During 2011, the company completed a review of its energy supply and trading activities and determined that the nature and purpose of transactions previously presented on a gross basis in Energy Supply and Trading Activities Income and Expenses in the Consolidated Statements of Comprehensive Income have evolved such that they are more appropriately reflected through net presentation. Realized and unrealized gains and losses, and the underlying settlement of these transactions, are now recognized and recorded on a net basis in Other Income. Prior period comparative figures have been reclassified for comparability with the current period presentation. Changes to the Consolidated Statements of Comprehensive Income are as follows:

Year ended December 31, 2010
($ millions, increase/(decrease))

Energy supply and trading activities income	(2 700)
Other income	102
Energy supply and trading activities expenses	(2 598)
Net earnings	—

Recently Announced Accounting Standards

Financial Instruments: Recognition and Measurement

In November 2009, as part of the International Accounting Standards Board (IASB) project to replace International Accounting Standard (IAS) 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the first phase of IFRS 9 *Financial Instruments*. The

standard contains requirements for the classification and measurement of financial assets. The new standard was further revised in October 2010 to include requirements regarding the classification and measurement of financial liabilities. The standard is applicable for Suncor's fiscal year beginning January 1, 2015. The full impact of the standard will not be known until the phases of the IASB's financial instruments project that address hedging and impairments have been completed.

Reporting Entity

In May 2011, the IASB issued IFRS 10 *Consolidated Financial Statements*, IFRS 11 *Joint Arrangements*, IFRS 12 *Disclosures of Interests in Other Entities*, and amendments to IAS 27 *Separate Financial Statements* and IAS 28 *Investments in Associates and Joint Ventures*.

IFRS 10 creates a single consolidation model by revising the definition of control in order to apply the same control criteria to all types of entities, including joint arrangements, associates and structured entities. IFRS 11 establishes a principles-based approach to the accounting for joint arrangements by focusing on the rights and obligations of the arrangement, and limits the application of proportionate consolidation accounting to arrangements that meet the definition of a joint operation. IFRS 12 is a comprehensive disclosure standard for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities. Amendments to IAS 27 and IAS 28 reflect requirements in the new standards.

These standards and amendments are effective for Suncor's fiscal year beginning January 1, 2013. The company is currently assessing the impact of these standards and amendments; therefore, the impact of these standards is not known at this time.

Fair Value Measurements

In May 2011, the IASB issued IFRS 13 *Fair Value Measurement*, which establishes a single source of guidance for all fair value measurements, clarifies the definition of fair value and enhances the disclosures on fair value measurements. This standard is effective for Suncor's fiscal year beginning January 1, 2013. The company does not anticipate significant changes to its fair value measurements and related disclosures as a result of this standard.

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 *Employee Benefits*, which revise the recognition, presentation and disclosure requirements for defined benefit plans. These amendments are effective for Suncor's fiscal year beginning January 1, 2013. The company does not anticipate significant impacts as a result of these amendments.

Production Stripping Costs

In October 2011, the IASB issued International Financial Reporting Interpretation Committee (IFRIC) 20 *Stripping Costs in the Production Phase of a Surface Mine*. This interpretation requires the capitalization of stripping costs from the production phase of a mine if an entity can demonstrate that it is probable that future economic benefits will be realized, that costs can be reliably measured, and that the component of the ore body for which access has been improved can be identified. This interpretation is effective for annual periods beginning on or after January 1, 2013. The company does not anticipate significant impacts as a result of this interpretation.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues, expenses, gains, losses, and disclosures of contingencies. These estimates and assumptions are subject to change based on experience and new information.

Critical accounting estimates are those estimates that require management to make assumptions about matters that are highly uncertain at the time the estimate is made, and those estimates where changes in critical assumptions that are within a range of reasonably possible outcomes would have a material impact on the company's financial condition, changes in financial condition or financial performance.

Critical accounting estimates are reviewed annually by the Audit Committee of the Board of Directors. The following are the critical accounting estimates used in the preparation of Suncor's December 31, 2011 audited Consolidated Financial Statements.

Oil and Gas Reserves and Resources

Measurements of depletion, depreciation, amortization, impairment and decommissioning and restoration obligations are determined in part based on the company's estimate of oil and gas reserves and resources. Although not reported as part of the company's audited Consolidated Financial Statements, these estimates of reserves and resources can have a significant impact on the Consolidated Financial Statements.

The estimation of reserves involves the exercise of professional judgment. Reserves and resources were evaluated or reviewed as at December 31, 2011 by qualified reserves evaluators in accordance with National

Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* . The reserves and resources estimates are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook.

Oil and gas reserves and resources estimates are based on a range of geological, technical and economic factors, including projected future rates of production, estimated commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Assumptions reflect market and regulatory conditions existing at December 31, 2011, which could differ significantly from other points in time throughout the year or in future periods.

Oil and Gas Activities

The company is required to use judgment when designating the nature of oil and gas activities as exploration, evaluation, development or production, and when determining whether the initial costs of these activities are capitalized.

Exploration and Evaluation Costs

The costs of drilling exploratory wells are initially capitalized pending the evaluation of commercially recoverable resources. The determination that commercial resources have been discovered requires judgment. If a judgment is made that there are no commercially recoverable reserves, the associated exploration costs are charged to exploration expense. Evaluation costs incurred when management is assessing whether there are commercially recoverable resources and designing development and front-end engineering plans are capitalized. Capitalized costs associated with exploration and evaluation assets are subject to ongoing technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. When management is making this assessment, changes to project economics, quantities of resources, expected production techniques, unsuccessful drilling, and estimated production costs and capital expenditures are important factors. If a judgment is made that extraction of the resources is not commercially viable, the associated exploration and evaluation assets are impaired and charged to net earnings as part of depreciation, depletion, amortization and impairment expense.

Development Costs

Management uses judgment to determine when exploration and evaluation assets are reclassified to property, plant and equipment. This decision considers several factors, including the existence of reserves, the receipt of the appropriate approvals from regulatory bodies and the company's internal project approval processes. After an oil and gas property is reclassified to property, plant and equipment, all subsequent development costs are capitalized.

Impairment of Assets

A cash-generating unit (CGU) is the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of the company's assets into CGUs requires significant judgment with respect to the integration between assets, the use of shared infrastructure, the existence of active markets for the company's products and the way in which management monitors operations.

At the end of each reporting period, the company is required to identify events or conditions that indicate that the net carrying value of a CGU might be impaired. If any such indication exists, the company must complete an impairment assessment for the CGU. A CGU is impaired when the net carrying value of the CGU exceeds management's estimate of the recoverable amount of the CGU, which is the higher of the CGU's fair value less costs to sell and its value-in-use. Fair value less costs to sell is the amount obtainable from the sale of the CGU in an arm's-length transaction between knowledgeable, willing parties, less costs of disposal. In determining fair value less costs to sell, recent market transactions are taken into account if available; however, in the absence of such transactions, an appropriate valuation model is used. Value-in-use is assessed using the present value of the future cash flows that the company expects to derive from the CGU. Where management determines that a CGU is impaired, the net carrying value of the CGU is reduced to the estimated recoverable amount, with the difference reported as part of depreciation, depletion, amortization and impairment expense.

Regardless of any indication of impairment, the company must complete an annual impairment assessment for any CGU, or group of CGUs, whose net carrying value includes indefinite-life intangible assets or an allocation of goodwill. For Suncor, this includes impairment assessments of the Oil Sands segment and the Refining and Marketing segment. For 2011, the company completed this review as at July 31, 2011, at which time there were no indications that goodwill was impaired.

At the end of each reporting period, the company must also assess if there are indicators that conditions causing a previous impairment have reversed. Where new estimates of recoverable amount exceed net carrying value, previously recorded impairment adjustments are reversed, up to the amount of the original impairment. An impairment of goodwill cannot be reversed.

For Suncor, the estimated recoverable amount of a CGU is predominantly determined using discounted net future

cash flow models. The key assumptions the company uses for estimating future cash flows are future commodity prices, expected production volumes, future operating and development costs, and refining margins. The estimated useful life of the CGU, the timing of future cash flows and discount rates are also important assumptions made by management. Changes to these assumptions will affect the recoverable amount of a CGU and may require a material impairment to the net carrying value of that CGU.

The company also assesses the impairment of assets when they are classified as held for sale or when they are reclassified from exploration and evaluation assets to property, plant and equipment in the Consolidated Balance Sheets. Assets held for sale are measured at the lower of net carrying value and fair value less costs to sell, which in this situation may also be determined based on expected sale proceeds when an offer has been received.

The following discusses important impairment assessments completed during 2011:

Libya

In the second quarter of 2011, the company recorded impairment charges of $259 million against property, plant and equipment, $211 million against exploration and evaluation assets, and $44 million against inventories pertaining to its operations in Libya, which had been shut-in at that time due to unrest. All impairment charges for Libyan assets are net of income taxes of $nil.

The net recoverable amount was estimated under a value-in-use premise and determined using discounted cash flow models under probability-weighted scenarios representing i) resumption of normal operations after one year; ii) resumption of normal operations after two years; and iii) total loss.

Scenarios involving the company resuming normal operations used current forecasts for the price of crude oil, estimates of operating and development expenditures based on the field redevelopment anticipated by Suncor's business plans prior to the suspension of operations, a discount rate (17%) that represented management's best estimate of the ongoing risk involved with operating in Libya, and management's best estimate of the incremental rebuilding costs to bring operations back on-stream. Management's forecasts for production were based on proved and probable reserves evaluated by external qualified reserves evaluators and risk-adjusted best estimates of contingent resources evaluated by Suncor's internal qualified reserves evaluators, both evaluated as at December 31, 2010. The scenario involving the company not resuming operations in Libya included the effects of the company not paying certain liabilities.

Later in 2011, a change in the Libyan government resulted in the lifting of certain sanctions that were impacting the company's operations in the country, and the company's joint venture partner was able to restart production in three of five fields by the end of 2011. The company started to receive production payments in January 2012, and the joint venture partner confirmed the existence of crude oil inventories that the company had written off, resulting in the company reversing $11 million of impairment charges.

Discussions with the Libyan authorities have commenced on the status of existing contract terms, including production volumes and time frames for future exploration commitments. There is also still unpredictability concerning production levels, expectations about the ramp up of production, and the extent of damage to the company's assets, which has not yet been fully assessed. Therefore, at December 31, 2011, there has been no change in the company's overall assessment of the impairment, and no reversal of impairment has been recognized, except for the $11 million associated with crude inventories noted above.

Syria

As a result of international sanctions announced in December 2011, the company suspended its operations in Syria and ceased recording production or revenues. Suncor performed an impairment test on its assets in Syria that determined that the assets were not impaired at December 31, 2011. The carrying value of the company's net assets in Syria at December 31, 2011 was approximately $900 million.

The net recoverable amount for the company's Syrian assets was estimated under a value-in-use premise and determined using discounted cash flow models, which take into account the long-term nature of the natural gas and light and medium oil reserves associated with these assets, under probability-weighted scenarios representing i) resumption of normal operations after six months; ii) resumption of normal operations after one year; iii) resumption of normal operations after two years; and iv) total loss. This calculation is most sensitive to management's assumption on the timing of the resumption of normal operations. If the probability weighting in the cash flow model was adjusted to reflect a 0% probability of the company resuming normal operations within the next twelve months, the company's Syrian assets may be impaired.

Scenarios involving the company resuming normal operations used current forecasts for the price of commodities, estimates of operating and development expenditures based on the field development anticipated by Suncor's business plans prior to the suspension of operations, a discount rate (17%) that represented

management's best estimate of the ongoing risk involved with operating in Syria, and an assumption that the company will receive payment for any production during its absence in Syria. Management's forecasts for production were based on proved and probable reserves evaluated by external qualified reserves evaluators as at December 31, 2011.

North America Onshore

As a result of decreases in price forecasts for natural gas, the company recorded pre-tax impairment charges of $100 million against certain CGUs in the North America Onshore business.

Net recoverable amounts for these CGUs were determined under a fair value less costs to sell premise, and determined using discounted cash flow models based on proved and probable reserves evaluated by external qualified reserves evaluators as at December 31, 2011, third-party price forecasts and a discount rate of 12%.

IFRS Transition Exemption

The company applied an IFRS transition exemption to record certain assets at fair value less costs to sell on the date of transition. The exemption was applied to refinery assets located in Eastern Canada and certain natural gas assets in Western Canada, and resulted in a total reduction of $906 million in the net carrying value of these assets. These adjustments are not impairments and cannot be reversed because they were applied as part of the IFRS transition. The company's estimates of fair value less costs to sell for these assets required management to make judgments and use assumptions at the transition date that were similar to those described above.

Summary

As at December 31, 2011, the company had $715 million of impairments on assets in the Exploration and Production segment, consisting of $503 million of impairments for Libya assets and $212 million of impairments on North America Onshore assets (2010 – $112 million).

Fair Value of Financial Instruments

To estimate the fair value of financial instruments, the company uses quoted market prices when available, or models that use observable market data. In addition to market information, Suncor incorporates transaction-specific details that market participants would use in a fair value measurement, including the impact of non-performance risk. Inputs used in determining fair value are characterized using a hierarchy that prioritizes inputs depending on the degree to which they are observable. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

Provisions for Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of property, plant and equipment, including, but not limited to, the reclamation of lands disturbed by mining oil sands, tailings ponds, producing well sites, and crude oil and natural gas processing plants. The provision for such liabilities is recognized only to the extent that there is a legal or constructive obligation associated with the retirement of an asset that the company is required to settle as a result of an existing or enacted law, statute, ordinance, written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel.

These provisions are based on estimated costs, which take into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible future use of the site. Since these estimates are specific to the assets involved, there are many individual judgments and assumptions underlying Suncor's total provision. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience and changes in costs. The expected timing of future decommissioning and restoration activities may change due to certain factors, including oil and gas reserves life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

When these provisions are initially recognized, an equal amount is capitalized as part of the cost of the associated asset and is amortized to expense over the life of the asset.

The fair value of these provisions is estimated by discounting the expected future cash flows using the company's credit-adjusted risk-free interest rate. In subsequent periods, the provision is adjusted for the passage of time by charging an amount to accretion of liabilities in financing expenses, based on the discount rate.

Suncor's provision for decommissioning and restoration costs increased by $1.168 billion in 2011. The most significant change in the provision resulting from a change in estimates was with respect to the expected timing of future reclamation activity, which has accelerated primarily as a result of recent advancements from the use of TRO$_{TM}$. The provision also increased due to a decrease in the average discount rate (2011 – 4.3%; 2010 – 5.4%) and new liabilities primarily associated with land disturbance in 2011, offset by the settlement of certain liabilities and the impacts of asset disposals.

Other Provisions

The determination of other provisions, including, but not limited to, provisions for royalty disputes, onerous contracts, litigation and constructive obligations, is a complex process that involves judgments about the outcomes of future events, the interpretation of laws and regulations, expected future cash flows and discount rates.

An onerous contract is one in which the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be received under it.

A constructive obligation is one where Suncor, by an established pattern of past practice, published policies, or a sufficiently current statement, has indicated that it will accept certain responsibilities and has created a valid expectation in other parties that it will discharge those responsibilities.

The company is involved in litigation and claims in the normal course of operations. As at December 31, 2011, management believes the result of any settlements related to such litigation or claims would not materially affect the financial position of the company.

Employee Future Benefits

The company provides benefits to employees and retired employees, including pensions and other post-retirement benefits. The obligations and costs of defined benefit pension and other post-retirement benefit plans are determined based on actuarial valuation methods and assumptions.

Assumptions typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, the return on plan assets, mortality rates and future medical costs. The accrued net benefit liability is reported as other long-term liabilities in the Consolidated Balance Sheets.

The fair value of plan assets is determined using market values. The estimated rate of return on plan assets in the portfolio considers the current level of returns on fixed income assets, the historical level of risk premium associated with other asset classes and the expected future returns on all asset classes. The discount rate assumption is based on the year-end interest rates for high quality bonds that mature at times concurrent with the company's benefit obligations. The estimated rate for compensation increases is based on management's judgment.

Actuarial valuations are subject to management's judgment. Actuarial gains and losses comprise changes to assumptions related to discount rates, expected return on plan assets and annual rates for compensation increases. They are accounted for on a prospective basis and may have a material impact on the amounts presented. Actuarial gains and losses are recognized in other comprehensive income in the Consolidated Statements of Comprehensive Income in the period incurred.

Income Taxes

The determination of the company's income tax provision is an inherently complex process, requiring management to interpret continually changing regulations and to make other judgments, including those about deferred income taxes that are discussed below.

Management believes that adequate provisions have been made for all income tax obligations, although the results of audits and reassessments and changes in the interpretations of standards may result in a material increase or decrease in the company's assets, liabilities and net earnings.

Deferred Income Taxes

A taxable or a deductible temporary difference may exist when there is a difference between the carrying value of an asset or liability and its respective tax basis. The reversal of deductible temporary differences results in deductible amounts when determining taxable income in future periods. The reversal of taxable temporary differences results in taxable amounts when determining taxable income of future periods.

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the company's estimate, the ability of the company to realize the deferred tax assets could be impacted.

Deferred tax liabilities are recognized when there are taxable temporary differences that will reverse and result in a future outflow of funds to a taxation authority. The company records a provision for the amount that is expected to be settled, which requires the application of judgment as to the ultimate outcome. Deferred tax liabilities could be impacted by changes in the company's estimate of the likelihood of a future outflow, the expected settlement amount, and the tax laws in the jurisdictions in which the company operates.

11. RISK FACTORS

The company is committed to a proactive program of enterprise risk management intended to enable decision-making through consistent identification of risks inherent to the assets and activities of Suncor. The company's enterprise risk committee, comprised of senior representatives from business and functional groups across Suncor, oversees entity-wide processes to identify, assess and report on the company's principal risks. A principal risk is an exposure that has the potential to materially impact the ability of one of the company's businesses or functions to meet or support a Suncor objective. The following provides a list of some of the risk factors relating to Suncor and its operations.

Commodity Price Volatility

Our financial performance is closely linked to prices for crude oil in our upstream businesses and prices for refined petroleum products in our downstream business, and, to a lesser extent, to natural gas prices in our upstream businesses, where natural gas is both an input and output of production processes. The values for all of these commodity prices can be influenced by global and regional supply and demand factors.

Crude oil prices are also affected by, among other things, global economic health and global economic growth (particularly in emerging markets), political developments, compliance or non-compliance with quotas imposed on members of the Organization of Petroleum Exporting Countries (OPEC), access to markets for crude oil, and weather. These factors impact the various types of crude oil and refined products differently and can impact differentials between light and heavy grades of crude oil (including blended bitumen), and between conventional and synthetic crude oil.

Suncor anticipates higher production of non-upgraded bitumen in future years, due mainly to expansion at Firebag. Due to its low viscosity, bitumen is blended with a light diluent or synthetic crude oil and sold as a heavy crude oil. The markets for heavy crude oil are more limited than those for light crude, making them more susceptible to supply and demand changes. Heavy crude oil receives lower market prices than light crude, due principally to the lower quality and value of the refined product yield, and the higher cost to transport the more viscous product on pipelines. The price differential between light crude and WCS is particularly important for Suncor. WCS is a pool of heavy crude oil and blended bitumen production from Western Canada. The market price for WCS is influenced by regional supply and demand factors, including the availability and price of diluent, and by the availability and cost of accessing primary markets through pipeline systems. Future price differentials are uncertain and widening light/heavy differentials could have a negative impact on our business, especially price realizations for bitumen that Suncor is unable to upgrade.

Refined petroleum product prices and refining margins are also affected by, among other things, crude oil prices, the availability of crude oil and other feedstocks, levels of refined product inventories, regional refinery availability, marketplace competitiveness, and other local market factors.

Natural gas prices in North America are affected primarily by supply and demand, and by prices for alternative energy sources.

All of these factors are beyond our control and can result in a high degree of price volatility.

Commodity prices and refining margins have fluctuated widely in recent years. Given the recent global economic uncertainty, we expect continued volatility and uncertainty in commodity prices in the near term, with the possibility that crude oil and refined petroleum products prices could revert to the low levels experienced in 2008 and 2009. A prolonged period of low prices could affect the value of our upstream and downstream assets and the level of spending on growth projects, and could result in the curtailment of production on some properties or include an impairment of carrying value. Accordingly, low commodity prices, particularly for crude oil, could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Government Policy

Suncor operates under federal, provincial, state and municipal legislation in numerous countries. The company is also subject to regulation and intervention by governments in oil and gas industry matters, such as land tenure, royalties, taxes (including income taxes), government fees, production rates, environmental protection controls, safety performance, the reduction of greenhouse gas (GHG) and other emissions, the export of crude oil, natural gas and other products, the company's interactions with foreign governments, the awarding or acquisition of exploration and production rights, oil sands leases 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.

Changes in government policy or regulation have a direct impact on Suncor's business, financial condition, results of operations and cash flow, as evidenced by such initiatives

as the Alberta government's royalty review program in 2007, and, more recently, by trade sanctions in Libya and Syria imposed by Canadian and other international governments, and increased production taxes in the U.K. Changes in government policy or regulation can also have an indirect impact on Suncor, such as opposition to new North American pipeline systems, such as Keystone XL, or incrementally over time through increasingly stringent environmental regulations or unfavourable income tax and royalty regimes. The result of such changes can also lead to additional compliance costs and staffing and resource levels, and also increase exposure to other principal risks of Suncor, including environmental or safety non-compliance and permit approvals.

Environmental Regulation

Changes in environmental regulation could have a material adverse effect on our business, financial condition, results of operations and cash flow by impacting the demand, formulation or quality of our products, or by requiring increased capital expenditures or distribution costs, which may or may not be recoverable in the marketplace. The complexity and breadth of changes in environmental regulation make it extremely difficult to predict the potential impact to Suncor. 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. Failure to comply with environmental regulation may result in the imposition of significant 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.

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;
- The use of hydraulic fracturing to assist in the recovery and production of oil and natural gas;
- Issues relating to land reclamation, restoration and wildlife habitat protection;
- Reformulated gasoline to support lower vehicle emissions;
- U.S. state or federal calculation and regulation of fuel life-cycle carbon content; and
- Regulation or policy by foreign governments or other organizations to limit purchases of oil produced from unconventional sources, such as the oil sands.

Climate Change Regulation

Future laws and regulations may impose significant liabilities on failure to comply with their requirements; however, Suncor expects the cost of meeting new environmental and climate change regulations will not be so high as to cause material disadvantage to the company or material damage to its competitive positioning. While it currently appears that GHG regulations and targets will continue to become more stringent, and while Suncor will continue efforts to reduce the carbon dioxide (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.

As part of our ongoing business planning, Suncor assesses potential costs associated with CO_2 emissions in our evaluation of future projects, based on our current understanding of pending and possible GHG 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. In the future, 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 a price range of $15-$45 per tonne of CO_2 equivalent as a base case, applied against a range of regulatory policy options and price sensitivities.

Although Suncor does not actively market into California, the implications of other states or countries adopting Low Carbon Fuel Standard legislation could pose a significant barrier to our exports of oil sands crude if the importing jurisdictions do not acknowledge efforts undertaken by the oil sands industry to meet the emissions intensity reductions legislated by the Government of Alberta.

In general, there remains uncertainty around the outcome and impacts of proposed or potential future climate change and other related environmental regulation. 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 Canadian 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. At this time, the company does not believe it is

possible to predict the nature of any requirements or the impact on Suncor's business, financial condition, results of operations and cash flow. The impact of developing regulations cannot be quantified at this time given the current lack of detail on how systems will operate.

Land Reclamation

There are risks associated specifically with our ability to reclaim tailings ponds containing mature fine tailings with TRO $_{TM}$ or other methods and technologies. Suncor expects that TRO$_{TM}$ will help the company reclaim existing tailings ponds. The success of TRO $_{TM}$ or any other methods of technology and the time to reclaim tailings ponds could increase or decrease our decommissioning and restoration cost estimates. Our failure or inability to adequately implement our reclamation plans, including our planned implementation of TRO$_{TM}$, could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow. In recent years, Suncor has increased collaboration with other participants in the oil sands industry to share technology and knowledge and to research alternative methods for tailings management.

Royalties

Royalties can be impacted by changes in crude oil and natural gas pricing, production volumes, foreign exchange rates, and capital and operating costs, changes to existing legislation or PSCs, and by results of regulatory audits of prior year filings and other unexpected events. Some of the issues where settlement with regulatory bodies may cause royalties expense or royalties payable to differ materially from provisions currently recorded include:

- For Suncor's mining operations (not including Syncrude), the BVM is based on the terms of Suncor's RAA, which we believe places certain limitations on the interim BVM as recently enacted, which modified the BVM for additional quality and transportation adjustments. For the years 2009 to 2010, Suncor filed non-compliance notices with the Alberta government, citing that reasonable quality adjustments in the determination of the Suncor BVM were not considered by the Alberta government as permitted by Suncor's RAA. Suncor has also filed with the Alberta government a Notice of Commencement of Arbitration under the Suncor RAA. The owners of the Syncrude joint venture have also filed a non-compliance notice in respect of the determination of the bitumen value under its 2008 agreements with the Alberta government.

- Suncor has also appealed the disallowance of certain costs under the New Royalty Framework in Alberta and certain costs under royalty agreements in Newfoundland and Labrador, such as insurance premiums.

The final determination of these matters may have a material impact on royalties payable to the respective governments and the company's royalties expense.

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 and other uncertainties arising from foreign government sovereignty over the company's international operations, 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;

- Compliance with existing and emerging anti-corruption laws, including the Foreign Corrupt Practices Act of the United States, the Corrupt Foreign Officials Act of Canada, and the United Kingdom Bribery Act;

- Renegotiation of contracts with governmental entities and quasi-governmental agencies;

- Changes in laws and policies governing operations of foreign-based companies; and

- Economic and legal sanctions (such as restrictions against countries experiencing political unrest, or countries that other governments may deem to sponsor terrorism).

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. In addition, 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.

In 2011, operations in both Libya and Syria were suspended as a result of the outbreak of political unrest and the resulting sanctions imposed by international governments. Discussions with the Libyan authorities continue on the status of existing contract terms, including production volumes and exploration commitments. There is still sufficient unpredictability underlying operations in this region, including the ramp up of production, the sustainability of current production rates and the extent of damage to the company's assets, which has not yet been fully assessed. As a result, there is

no assurance that production will return to previous levels or continue at current levels.

In response to sanctions and escalating political unrest in Syria, Suncor declared force majeure in December 2011, withdrew its expatriate staff and stopped recording production from Syria. Suncor's assessment of the situation as at December 31, 2011 did not require the company to record an impairment charge against its assets in Syria; however, should the current situation persist or worsen, such that Suncor is unable to resume operations in the near term, the company believes its assets in Syria could be impaired in the future. There is no assurance as to when Suncor's production from Syrian assets will resume or return to previous levels. Suncor's operations in Syria represented approximately 3% of the company's consolidated net earnings and 3% of the company's cash flow from operations in 2011. The carrying value of Suncor's net assets in Syria at December 31, 2011 was approximately $900 million.

The impact that future potential terrorist attacks, regional hostilities or political violence may have on the oil and gas industry, and on our operations in particular, is not known at this time. This uncertainty may affect operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly crude oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or collateral damage of, an act of terror, political violence or war. We may be required to incur significant costs in the future to safeguard our assets against terrorist activities or to remediate potential damage to our facilities. There can be no assurance that we will be successful in protecting ourselves against these risks and the related financial consequences.

Environmental Health and Safety (EHS) Regulatory Non-Compliance

The company is required to comply with a large number of EHS regulations under a variety of Canadian, U.S., U.K. and other foreign, federal, provincial, territorial, state and municipal laws and regulations, as described in the Industry Conditions – Environmental Regulation section of the 2011 AIF. Failure to comply with these regulations may result in the imposition of fines and penalties, censure, liability for cleanup costs and damages, and the loss of important licences and permits, which could also have a material adverse effect on our business, financial condition, results of operations and cash flow. Compliance can be affected by the loss of skilled staff, inadequate internal processes and compliance auditing.

Operational Outages and Major Environmental or Safety Incidents

Each of our primary operating segments – Oil Sands, Exploration and Production, and Refining and Marketing – demand significant levels of investment in the design, operation and maintenance of facilities, and, therefore, carry the additional economic risk associated with operating reliably or enduring a protracted operational outage. These businesses also carry the risks associated with environmental and safety performance, which is closely scrutinized by governments, non-government organizations, the public and the media, and could result in a suspension of or inability to obtain regulatory approvals and permits, or, in the case of a major environmental or safety incident, civil suits or charges against the company.

Generally, our operations are subject to operational hazards and risks such as fires, explosions, blow-outs, power outages, severe winter climate conditions, and the migration of harmful substances such as oil spills, gaseous leaks, or a release of tailings into water systems, any of which can interrupt operations or cause personal injury or death, or damage to property, equipment, the environment, and information technology systems and related data and control systems.

The reliable operation of production and processing facilities at planned levels and our ability to produce higher value products can also be impacted by failure to follow operating procedures or operate within established operating parameters, equipment failure through inadequate maintenance, unanticipated erosion or corrosion of facilities, manufacturing and engineering flaws, and labour shortage or interruption. We are also subject to operational risks such as sabotage, terrorism, trespass, theft and malicious software or network attacks.

The efficient operation of our business is dependent on computer hardware and software systems. Information systems are vulnerable to security breaches by computer hackers and cyberterrorists. We rely on industry accepted security measures and technology to securely maintain confidential and proprietary information stored on our information systems. However, these measures and technology may not adequately prevent security breaches. In addition, the unavailability of the information systems or the failure of these systems to perform as anticipated for any reason could disrupt our business and could result in decreased performance and increased operating costs, causing our business and results of operations to suffer. Any significant interruption or failure of our information systems or any significant breach of security could adversely affect our business and results of 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. Disruptions in pipeline service could adversely affect commodity prices, Suncor's price realizations, refining operations and sales volumes, or limit our ability to deliver production. These interruptions may be caused by the inability of the pipeline to operate or by the oversupply of feedstock into the system that exceeds pipeline capacity. There can be no certainty that short-term operational constraints on pipeline systems arising from pipeline interruption and/or increased supply of crude oil will not occur. In addition, planned or unplanned shutdowns or closures of our refinery customers or third-party suppliers may limit our availability to deliver feedstock. All of these events could have negative implications on sales and cash from operating activities.

For Suncor's Oil Sands operations, mining oil sands ore, extracting bitumen from mined ore, producing bitumen through in situ methods, 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. 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, Suncor has two upgrader facilities that include three secondary upgrading units, which provide us with the flexibility to conduct periodic planned maintenance events on one facility while continuing production from the other.

For Suncor's upstream businesses, there are risks and uncertainties associated with drilling for oil and natural gas, the operation and development of such properties and wells (including encountering unexpected formations, pressures, ore grade qualities, or the presence of H_2S), premature declines of reservoirs, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, other accidents, and pollution and other environmental risks.

Our Exploration and Production 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 and other extreme weather conditions. 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 consequence of catastrophic events, such as blow-outs, occurring in offshore operations can be more difficult and time-consuming to remedy. 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. Successful remediation of these events may be adversely affected by the water depths, pressures and cold temperatures encountered in the ocean, shortages of equipment and specialists required to work in these conditions, or the absence of appropriate technology to resolve the event. Damage to the environment, particularly through oil spillage or extensive, uncontrolled fires or death, could result from these offshore operations. Our offshore operations could also be affected by the actions of our contractors and agents that could result in similar catastrophic events at their facilities, or could be indirectly affected by catastrophic events occurring at other third-party offshore operations. In either case, this could give rise to liability, damage to our equipment, harm to individuals, force a shutdown of our facilities or operations, or result in a shortage of appropriate equipment or specialists required to perform our planned operations.

In particular, East Coast Canada operations can be impacted by winter storms, pack ice, icebergs and fog. During the winter storm season (typically 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. During the spring, pack ice and icebergs drifting in the area of our offshore facilities have resulted in precautionary shut in of FPSO production and drilling delays. In late spring and early summer, fog also impacts our ability to transfer personnel to the offshore facilities by helicopter.

Our Refining and Marketing operations are subject to all of the risks normally inherent in the operation of refineries, terminals, pipelines, other distribution facilities and service stations, including loss of product, slowdowns due to equipment failures, unavailability of feedstock, price and quality of feedstock or other incidents.

Losses resulting from the occurrence of any of these risks identified above could have a material adverse effect on Suncor's 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. It is possible that our insurance coverage will not be sufficient to address the costs arising out of the allocation of liabilities and risk of loss arising from offshore operations. Suncor also has a captive insurance entity to provide additional business interruption coverage for potential losses.

Project Execution and Partner Risk

There are certain risks associated with the execution of our major projects and the commissioning and integration of new facilities within our existing asset base, the occurrence of which could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Project execution risk consists of three related primary risks:

- Engineering – a failure in the specification, design or technology selection;
- Construction – a failure to build the project in the approved time and at the agreed cost; and
- Commissioning and start-up – a failure of the facility to meet agreed performance targets, including operating costs, efficiency, yield and maintenance costs.

Management believes the execution of major projects presents issues that require prudent risk management. Suncor may provide cost estimates for major projects at the conceptual stage, prior to commencement or completion of the final scope design and detailed engineering necessary to reduce the margin of error of such cost estimates. Accordingly, actual costs can vary from estimates, and these differences can be material. Project execution can also be impacted by:

- Failure to comply with Suncor's project implementation model;
- The availability, scheduling and cost of materials, equipment and qualified personnel;
- The complexities associated with integrating and managing contractor staff and suppliers in a confined construction area;
- Our ability to obtain the necessary environmental and other regulatory approvals;
- 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.

Other entities operate a portion of the assets in which Suncor has ownership interests. Suncor's dependence on its partners – the operator and other working interest owners for these assets – and its limited ability to influence operations and associated costs could materially adversely affect Suncor's business, financial condition, results of operations and cash flow. The success and timing of Suncor's activities on assets operated by others depend upon a number of factors that are outside of Suncor's control, including the timing and amount of capital expenditures, the timing and amount of operational and maintenance expenditures, the operator's expertise, financial resources and risk management practices, the approval of other participants, and the selection of technology.

These partners may have objectives and interests that do not coincide with and may conflict with Suncor's interests. Major capital decisions affecting jointly owned assets may require agreement among the partners, while certain operational decisions may be made solely at the discretion of the operator of the applicable assets. While the partners generally seek consensus with respect to major decisions concerning the direction and operation of the assets, no assurance can be provided that the future demands or expectations of either party relating to such assets will be met satisfactorily or in a timely manner. Failure to satisfactorily meet demands or expectations by either party may affect our participation in the operation of such assets, our ability to obtain or maintain necessary licences or approvals, and the timing for undertaking various activities.

Corporate Reputation

The public perception of integrated oil and gas companies and their operations may pose issues related to development and operating approvals or market access for products, which may have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Development of the oil sands has figured prominently in recent political, media and activist commentary on the subjects of pipeline transportation, climate change, GHG emissions, water usage and environmental damage, which may directly or indirectly harm the profitability of our current oil sands projects and the viability of future oil sands projects in a number of ways, including:

- Creating significant regulatory uncertainty that challenges economic modelling of future projects and potentially delays sanctioning;
- Motivating extraordinary environmental and emissions regulation of those projects by governmental authorities that could result in changes to facility design and operating requirements, thereby potentially increasing

the cost of construction, operation and abandonment; and

- Compelling legislation or policy that limits the purchase of crude oil produced from the Athabasca oil sands by governments and other institutional consumers that, in turn, limits the market for this crude oil and reduces its price.

Concerns such as those raised above may also harm our corporate reputation and limit our ability to transport our products or access land and joint venture opportunities in other jurisdictions throughout the world. Investors may respond by applying a discount to Suncor's shares, thereby diminishing the company's value, or may hinder Suncor in its ability to influence government policy.

Permit Approvals

Before proceeding with most major projects, including significant changes to existing operations, Suncor must obtain various federal, provincial or state permits and regulatory approvals. Suncor must also obtain licences to operate certain assets. These processes can involve, among other things, stakeholder consultation, environmental impact assessments and public hearings, and may be subject to conditions, including security deposit obligations and other commitments. Suncor can also be indirectly impacted by a third party's inability to obtain regulatory approval for a shared infrastructure project.

Failure to obtain regulatory approvals, or failure to obtain them on a timely basis or 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 Suncor's business, financial condition, results of operations and cash flow.

Skills and Resource Shortage

The successful operation of Suncor's businesses and our ability to expand operations will depend upon the availability of, and competition for, skilled labour and materials supply. There is a risk that we may have difficulty sourcing the required labour for current and future operations. The risk could manifest itself primarily through an inability to recruit new staff without a dilution of talent, to train, develop and retain high quality and experienced staff without unacceptably high attrition, and to satisfy an employee's work/life balance and desire for competitive compensation. The labour market in Alberta is particularly tight due to the growth of the oil sands industry and higher crude oil prices. The increasing age of our existing workforce adds further pressure to this situation. Materials may also 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.

Change Capacity

In order to achieve Suncor's business objectives, the company must operate efficiently, reliably and safely, and, at the same time, deliver growth and sustaining projects safely, on budget and on schedule. The ability to balance these two sets of objectives is critically important to Suncor to deliver value to shareholders and stakeholders. These objectives demand a large number of improvement initiatives that compete for resources, and may negatively impact the company should there be inadequate screening of project requests or consideration of the cumulative impacts of prior and parallel initiatives on people, processes and systems. There is a risk that these objectives may exceed Suncor's capacity to adopt and implement change.

Cost Management

Production from oil sands through mining, upgrading and in situ recovery is, relative to most major conventional hydrocarbon reserves, a higher cost resource to develop and produce. There is also a perception among many stakeholders that the oil sands industry, including Suncor, has little ability to control costs. Suncor is exposed to the risks of growing or uncontrollable operating costs, which could reduce profitability and cash flow that might otherwise be directed towards growth or dividends, and major project capital costs, which could constrain Suncor's ability to execute high quality projects that deliver lower operating costs. Factors contributing to these risks include, but are not limited to, the skills and resource shortage, the long-term success of existing and new in situ technologies, and the geology and reserves characterization of in situ reserves that can lead to higher steam-to-oil ratios and lower production.

Other Risk Factors

A detailed discussion of additional risk factors is presented in our most recent Annual Information Form/Form 40-F, filed with securities regulators.

12. OTHER ITEMS

CONTROL ENVIRONMENT

Based on their evaluation as of December 31, 2011, Suncor's chief executive officer and chief financial officer concluded that the company's 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 the company in reports that are filed or submitted 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, 2011, there were no changes in the internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) to 15d-15(f)) that occurred during 2011 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting. Management will continue to periodically evaluate the company's disclosure controls and procedures and internal control over financial reporting and will make any modifications from time to time as deemed necessary.

As a result of past unrest in Libya and current events in Syria, Suncor is not able to monitor the status of all of its facilities, including whether certain facilities have suffered damages. Suncor has assessed and is continually monitoring the control environment in these countries and does not consider the changes to have a material impact on the company's overall internal control over financial reporting.

The effectiveness of our internal control over financial reporting as at December 31, 2011 was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2011.

Based on their inherent limitations, disclosure controls and procedures and internal control 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.

CORPORATE GUIDANCE

Detailed guidance on the company's outlook for 2012 production, capital expenditures and other items can be found in Suncor's 2011 Annual Report, available on www.sedar.com, and Suncor's corporate guidance available on its website at www.suncor.com/guidance.

13. NON-GAAP FINANCIAL MEASURES ADVISORY

Certain financial measures in this MD&A – namely operating earnings, cash flow from operations, ROCE and Oil Sands cash operating costs – are not prescribed by GAAP. These non-GAAP financial measures do not have any standardized meaning and, therefore, are unlikely to be comparable to similar measures presented by other companies. These non-GAAP financial measures are included because management uses the information to analyze operating performance, leverage and liquidity. Therefore, these non-GAAP financial measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Operating Earnings

Operating earnings is a non-GAAP financial measure that adjusts net earnings for significant items that are not indicative of operating performance. Management uses operating earnings to evaluate operating performance because management believes it provides better comparability between periods. All reconciling items are presented on an after-tax basis.

Prior period operating earnings have been restated in this MD&A. In the first quarter of 2011, three operating earnings adjustments – mark-to-market valuation of stock-based compensation, project start-up costs and costs related to the deferral of growth projects – were eliminated from the operating earnings reconciliation due to their relatively minor impact on operating earnings, except for the after-tax impact of $299 million for costs related to the deferral of growth projects in the Oil Sands segment, which was not eliminated from 2009 operating earnings as an operating earnings adjustment. Less significant individual gains and losses on disposals were also removed from operating earnings reconciling items reported in 2010. Finally, adjustments to net earnings for the transition to IFRS also had an impact on operating earnings and existing operating earnings adjustments.

The following is a reconciliation of operating earnings as reported in Suncor's MD&A dated February 24, 2011 to operating earnings as reported in this MD&A:

Year ended December 31 [1] ($ millions)	Oil Sands		Exploration and Production		Refining and Marketing		Corporate Energy Trading and Eliminations		Total	
	2010	2009	2010	2009	2010	2009	2010	2009	2010	2009
Operating earnings (loss), as previously reported [2]	1 535	1 116	1 124	171	782	473	(709)	(480)	2 732	1 280
Removal of operating earnings adjustments:										
Mark-to-market valuation of stock-based compensation	(31)	(28)	(23)	(21)	(30)	(17)	(19)	(58)	(103)	(124)
(Loss) gain on significant disposals	(4)	—	—	—	26	—	—	—	22	—
Project start-up costs	(55)	(40)	(3)	—	—	—	—	—	(58)	(40)
Costs related to deferral of growth projects	(94)	—	—	—	—	(1)	—	—	(94)	(1)
IFRS adjustments:										
Net earnings	28	—	218	—	18	—	(6)	—	258	—
Operating earnings reconciling items:										
Impairments and write-offs	—	—	(85)	—	—	—	—	—	(85)	—
Gain on significant disposals	—	—	(38)	—	—	—	—	—	(38)	—
Operating earnings (loss), as restated in this MD&A	**1 379**	**1 048**	**1 193**	**150**	**796**	**455**	**(734)**	**(538)**	**2 634**	**1 115**

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Operating earnings (loss) includes amounts classified as discontinued operations in 2010 under Previous GAAP.

The following is a reconciliation of net earnings to operating earnings for Suncor's last five years of operations. Operating earnings for 2007 to 2009 are reported under Previous GAAP and have been adjusted from operating earnings previously reported for the removal of project start-up costs and mark-to-market valuation of stock-based compensation.

($ millions)	**2011**	2010	2009	2008	2007
Net earnings as reported	**4 304**	3 829	1 146	2 137	2 983
Unrealized foreign exchange loss (gain) on U.S. dollar denominated long-term debt	**161**	(372)	(798)	852	(215)
Impairments and write-offs	**629**	306	42	—	—
Impact of income tax rate adjustments on deferred income taxes	**442**	—	4	—	(427)
Loss (gain) on significant disposals	**107**	(826)	39	—	—
Adjustments to provisions for assets acquired through the merger	**31**	68	97	—	—
Change in fair value of commodity derivatives used for risk management, net of realizations	**—**	(233)	499	(372)	—
Redetermination of working interests in Terra Nova	**—**	(166)	24	—	—
Modification of the bitumen valuation methodology	**—**	(51)	50	—	—
Merger and integration costs	**—**	79	151	—	—
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	—	(438)	—	—
Costs related to deferral of growth projects	**—**	—	299	—	—
Operating earnings	**5 674**	2 634	1 115	2 617	2 341

Return on Capital Employed (ROCE)

ROCE is a non-GAAP financial measure that management uses to analyze operating performance and the efficiency of Suncor's capital allocation process. The following is a reconciliation of ROCE for Suncor's last five years of operations. ROCE for 2007 to 2009 are reported under Previous GAAP.

Year ended December 31 ($ millions, except as noted)		**2011**	2010	2009	2008	2007
Adjustments to net earnings						
Net earnings		**4 304**	3 829	1 146	2 137	2 983
Add after-tax amounts for:						
Unrealized foreign exchange loss (gain) on U.S. dollar denominated long-term debt		**161**	(372)	(798)	852	(215)
Net interest expense		**83**	327	289	—	36
	A	**4 548**	3 784	637	2 989	2 804
Capital employed – beginning of twelve-month period						
Net debt		**11 254**	13 516	7 226	3 248	1 849
Shareholders' equity		**35 192**	32 485	14 523	11 896	9 084
	D	**46 446**	46 001	21 749	15 144	10 933
Capital employed – end of twelve-month period						
Net debt		**6 976**	11 254	13 377	7 226	3 248
Shareholders' equity		**38 600**	35 192	34 111	14 523	11 896
		45 576	46 446	47 488	21 749	15 144
Average capital employed (1)	B	**44 956**	46 075	35 128	18 447	13 039
ROCE – including major projects in progress (%)	A/B	**10.1**	8.2	1.8	16.2	21.5
Average capitalized costs related to major projects in progress	C	**12 106**	12 890	10 655	5 149	3 454
ROCE – excluding major projects in progress (%)	A/(B-C)	**13.8**	11.4	2.6	22.5	29.3

(1) For 2009 to 2011, average capital employed is calculated as a thirteen-month average of the capital employed balance at the beginning of the twelve-month period and the month-end capital employed balances throughout the remainder of the twelve-month period. For 2007 and 2008, average capital employed is calculated on the basis of a simple average (B+D)/2. This change in calculation was made as a result of the significant capital employed acquired in the merger with Petro-Canada in 2009. Figures for capital employed at the beginning and end of the twelve-month period are presented to show the changes in the components of the calculation over the twelve-month period.

Cash Flow from Operations

Cash flow from operations is a non-GAAP financial measure that adjusts a GAAP measure – Cash flow provided by operating activities – for changes in non-cash working capital, which management uses to analyze operating performance and liquidity. Changes to non-cash working capital can include, among other factors, fluctuations for the timing or payment of risk management positions, offshore feedstock purchases, and fuel and income taxes, which management believes reduces comparability between periods.

Year ended December 31 ($ millions) [1]	Oil Sands			Exploration and Production			Refining and Marketing		
	2011	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Net earnings (loss)	**2 603**	1 520	557	**306**	1 938	78	**1 726**	819	407
Adjustments for:									
Depreciation, depletion, amortization and impairment	**1 374**	1 310	922	**2 035**	1 978	1 032	**444**	440	317
Deferred income taxes	**895**	487	(643)	**354**	196	(96)	**494**	269	99
Accretion of liabilities	**85**	130	111	**69**	103	43	**3**	2	1
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**—**	—	—	**—**	—	—	**—**	—	—
Change in fair value of derivative contracts	**—**	(316)	960	**—**	—	—	**3**	—	(14)
Loss (gain) on disposal of assets	**122**	14	70	**31**	(998)	(20)	**(16)**	(30)	16
Share-based compensation	**(35)**	55	90	**(4)**	24	31	**(21)**	39	35
Exploration expense	**—**	—	—	**28**	96	183	**—**	—	—
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	—	(438)	**—**	—	—	**—**	—	—
Other	**(472)**	(423)	(378)	**27**	(12)	29	**(59)**	(1)	60
Cash flow from (used in) operations	**4 572**	2 777	1 251	**2 846**	3 325	1 280	**2 574**	1 538	921
(Increase) decrease in non-cash working capital	**(676)**	(890)	(202)	**398**	(320)	(78)	**600**	(260)	(270)
Cash flow provided by (used in) operating activities	**3 896**	1 887	1 049	**3 244**	3 005	1 202	**3 174**	1 278	651

Year ended December 31 ($ millions) [1]	Corporate, Energy Trading and Eliminations			Total		
	2011	2010	2009	**2011**	2010	2009
Net earnings (loss)	**(331)**	(448)	104	**4 304**	3 829	1 146
Adjustments for:						
Depreciation, depletion, amortization and impairment	**99**	75	35	**3 952**	3 803	2 306
Deferred income taxes	**(99)**	(201)	(85)	**1 644**	751	(725)
Accretion of liabilities	**—**	—	—	**157**	235	155
Unrealized foreign exchange loss (gain) on U.S. dollar denominated long-term debt	**183**	(426)	(858)	**183**	(426)	(858)
Change in fair value of derivative contracts	**(43)**	31	34	**(40)**	(285)	980
Loss (gain) on disposal of assets	**(1)**	39	—	**136**	(975)	66
Share-based compensation	**(42)**	(5)	106	**(102)**	113	262
Exploration expense	**—**	—	—	**28**	96	183
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	—	—	**—**	—	(438)
Other	**(12)**	(49)	11	**(516)**	(485)	(278)
Cash flow from (used in) operations	**(246)**	(984)	(653)	**9 746**	6 656	2 799
(Increase) decrease in non-cash working capital	**(80)**	300	326	**242**	(1 170)	(224)
Cash flow provided by (used in) operating activities	**(326)**	(684)	(327)	**9 988**	5 486	2 575

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

The following is a reconciliation of cash flow from operations for Suncor's last five years of operations. Cash flow from operations for 2007 to 2009 is reported under Previous GAAP.

($ millions)	**2011**	2010	2009	2008	2007
Cash flow provided by operating activities	**9 988**	5 486	2 575	4 462	3 893
(Decrease) increase in non-cash working capital	**(242)**	1 170	224	(405)	144
Cash flow from operations	**9 746**	6 656	2 799	4 057	4 037

Oil Sands Cash Operating Costs

Oil Sands cash operating costs and cash operating costs per barrel are non-GAAP financial measures that adjust operating, selling and general expense for significant items that do not reflect production costs for Oil Sands that are within the company's control or that do not directly affect routine production activities. Management uses cash operating costs to evaluate operating performance because management believes it provides better comparability between periods.

($ millions)	**2011**	2010	2009
Operating, selling and general expense [1]	**5 169**	4 537	4 277
Less: Syncrude-related operating expenses	**(529)**	(473)	(199)
Less: Other non-production costs [2]	**(299)**	(201)	(517)
Other adjustments [3]	**138**	127	38
Oil Sands cash operating costs	**4 479**	3 990	3 599
Oil Sands cash operating costs ($/bbl)	**40.20**	38.65	33.95

(1) 2009 data is prepared under Previous GAAP. See the Advisories – Basis of Presentation section of this MD&A.

(2) Significant non-production costs include, but are not limited to, share-based compensation adjustments, costs related to the remobilization and deferral of growth projects, and the expense recognized as part of a non-monetary arrangement involving a third-party processor.

(3) Other adjustments include the effects of changes in inventory valuation, the accretion of liabilities for reclamation and restoration provisions, and the cost of purchased diluent.

Cash operating costs have also been restated for the transition to IFRS. The following table reconciles amounts previously reported to those presented in this MD&A:

	Year ended December 31, 2010 $ millions	$/bbl
Oil Sands cash operating costs, as previously reported	4 012	38.85
IFRS adjustments:		
Accretion of liabilities	(16)	
Operating, selling and general expense	(6)	
Oil Sands cash operating costs, as restated in this MD&A	3 990	38.65

14. ADVISORY – FORWARD-LOOKING INFORMATION

This MD&A contains certain forward-looking statements and other information based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of information available at the time the statement was made and consider Suncor's experience and its perception of historical trends, including expectations and assumptions concerning: the accuracy of reserves and resources 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. In addition, all other statements and other information that address expectations or projections about the future, and other statements and information about Suncor's strategy for growth, expected and future expenditures or investment decisions, commodity prices, costs, schedules, production volumes, operating and financial results, future financing and capital activities, and the expected impact of future commitments are forward-looking statements. Some of the forward-looking statements and information may be identified by words like "expects", "anticipates", "estimates", "plans", "scheduled", "intends", "believes", "projects", "indicates", "could", "focus", "vision", "goal", "outlook", "proposed", "target", "objective", "continue" and similar expressions.

Forward-looking statements in this MD&A include references to:

Suncor's expectations about production volumes and the performance of its existing assets, including:

- *Lower bitumen ore grade quality at the Millennium mine face will impact operations until the start of the fourth quarter of 2012, at which point the bitumen ore grade quality is expected to return to previous levels;*
- *New wells coming on-stream at MacKay River in the fourth quarter of 2011 and throughout 2012, combined with well workovers, will offset natural declines from existing well pairs;*
- *Significant incremental or sustained production from the HSEU will not occur until further development drilling and subsea infrastructure comes on-stream, which is expected by 2014;*
- *The continuation of the ramp up of bitumen production from the NSE, and that the NSE will improve productivity of overall mining operations and decrease operating costs by alleviating congestion in the Millennium mining area and reducing average haul distances; and*
- *If regulatory approval is obtained to increase the NSE project area, Suncor's expectation that the expanded area will provide additional recoverable bitumen.*

The anticipated duration and impact of planned maintenance events, including:

- *The event scheduled for the second quarter of 2012 at Oil Sands Base, when the company expects to shut down one coker unit at Upgrader 1;*
- *The event scheduled for the third quarter of 2012 at Oil Sands Base, when the company expects to complete maintenance on the vacuum tower and shut down one coker unit at Upgrader 2;*
- *Suncor's expectations that it will complete maintenance on secondary upgrading units at both Upgrader 1 and Upgrader 2 during 2012;*
- *The 21-week dockside maintenance program planned for Terra Nova in 2012 in the second half of 2012, during which the company plans to replace the FPSO water injection swivel and complete the replacement of subsea infrastructure anticipated to remediate H_2S issues, and that the company expects a return to the field with resumption of production prior to the end of 2012;*
- *The 18-week off-station maintenance program for White Rose that is scheduled to commence during the second quarter of 2012, primarily to address issues with the FPSO propulsion system;*
- *Events scheduled to occur at Hibernia and Buzzard in the third quarter of 2012;*
- *Suncor's expectation that there will be no production from Terra Nova during its dockside maintenance program and no production from White Rose during its off-station maintenance program, and that effective execution of these programs will set the company up for continued success; and*
- *Outages planned for 2012 at the company's refineries, including crude unit maintenance at the Sarnia and Commerce City refineries and minor secondary process unit maintenance at all four refineries.*

Suncor's expectations about where future capital expenditures will be directed, the timing for completion of growth and other significant projects, and the results of such projects, including:

- *The project to reduce benzene content in gasoline production at the Commerce City refinery is expected to be completed by the second quarter of 2012;*
- *Cost estimates and target completion dates provided in the Significant Growth Projects Update table;*

- *Suncor's expectations that it will commission the Firebag Stage 3 cogeneration units in the first quarter of 2012;*
- *Initial bitumen production from the second and third well pads for the Firebag Stage 3 expansion is expected in the first half of 2012, and the ramp up of production from the Firebag Stage 3 expansion is expected to continue throughout 2012 and reach peak production levels during the second half of 2013;*
- *Planned capacity for facilities at each of the Firebag Stage 3 and Stage 4 expansions is 62,500 bbls/d of bitumen and that Stage 4 will add equivalent barrels of production to Stage 3;*
- *Suncor's expectations for the Firebag Stage 4 expansion that in 2012 it will continue construction of well pads, central processing facilities and cogeneration units, and initiate steaming of the first well pad in the fourth quarter of 2012 so that first oil can be achieved late in the first quarter of 2013;*
- *Suncor's expectations that the hydrotreater portion of the MNU will start up in 2012, commissioning of the MNU hydrogen plant will be completed by the middle of 2012, and that the MNU will improve the reliability and availability of Suncor's upgrading facilities;*
- *Suncor's expectations that the Golden Eagle Area Development will include stand-alone facilities designed for 70,000 boe/d of gross production, and that 2012 capital expenditure activity in 2012 will focus on construction and fabrication of topsides and the jacket for the GBS;*
- *The company's plans to construct more tailings drying facilities and expectations that it will complete the TRO $_{TM}$ infrastructure project by the fourth quarter of 2012;*
- *Other capital spending for Oil Sands Base is expected to focus on sustaining capital investments, which maintain production capacities at existing facilities, and include costs for planned maintenance events, catalyst, truck and shovel replacement, and the replacements for utilities, roads and other facilities;*
- *In situ capital spending is expected to focus on continuing to build well pads at Firebag and MacKay River and continuing the infill well program at Firebag;*
- *The company's plan to present to Suncor's Board of Directors for sanctioning the budget for the combined development of the Voyageur upgrader, Fort Hills and Joslyn projects in 2013;*
- *Suncor's expectations that capital spending in 2012 for the Voyageur upgrader project will focus primarily on validating project scope, developing the project execution plan, engineering and progressing site preparation;*
- *Suncor's expectations that capital spending in 2012 for the Fort Hills project will focus primarily on progressing design basis memorandum engineering and site preparation, and procuring long-lead items;*
- *Suncor's expectations that capital spending in 2012 for the Joslyn project will focus on further design work, progressing front-end engineering and site preparation;*
- *Capital expenditures in 2012 for Syncrude will focus on the mine train replacement for the Mildred Lake mine, the mine train relocation at the Aurora mine and sustaining maintenance initiatives;*
- *Suncor's expectations that the second pilot well for water injection support in the White Rose Extensions will be completed in the second quarter of 2012 and that results from the pilot project, along with ongoing evaluations, will help define the scope of future development for the West White Rose field;*
- *The company's expectations for the Hebron project that front-end engineering will be finalized, detailed design will commence and major construction contracts will be awarded, and that it will receive a regulatory approval decision in 2012, followed by a sanction decision by joint venture owners;*
- *For 2012, the company's expectations that it will commence drilling an exploration well for the Romeo joint venture prospect in the U.K. portion of the North Sea and participate in a non-operated exploration well in the Norway portion of the North Sea;*
- *Suncor's expectations that other capital expenditures for East Coast Canada operations will focus on development drilling for Terra Nova, Hibernia and White Rose, the water injection swivel replacement for the FPSO and H_2S remediation activity at Terra Nova, the propulsion system maintenance for the White Rose FPSO, and the procurement of subsea equipment for the development of the HSEU;*
- *The company's expectations that it will commence the drilling of an appraisal well in its Beta discovery in the first quarter of 2012 and that it will participate in an exploration well offshore Norway; and*
- *For North America Onshore operations, the company's plans to continue exploration in the Cardium oil formation and Montney shale gas formation.*

Other elements of Suncor's strategy and operational update for 2012, including:

- *The expectation that Oil Sands operational excellence initiatives will continuously improve plant utilization and workforce productivity;*
- *The company's portfolio of in situ technology projects, which is expected to drive improvements and efficiencies*

in current production and develop future opportunities, and the focus of this portfolio on subsurface and surface challenges;

- *The company's expectations that the development of the Golden Eagle, HSEU, White Rose Extensions and Hebron will be an attractive opportunity to provide low-cost production and generate future cash flow;*
- *That North America Onshore operations will direct attention to cost reduction while pursuing unconventional and liquids-rich plays;*
- *Expectations that Refining and Marketing will continue to focus on the safety and reliability of its operations, leverage the company's strong brand to increase non-petroleum revenues through our network of convenience stores and car washes, and expand the lubricants product offering; and*
- *The Energy Trading business will optimize capacities associated with existing arrangements for pipeline and storage capacity, and optimize existing and future production.*

Also:

- *Suncor's assessment of the situation in Syria, including its determination of the net recoverable value of net assets in Syria that did not indicate than an impairment charge is required at this time, Suncor's expectations about recovering its share of any production during the period of force majeure, if force majeure is lifted, and Suncor's belief that it is entitled to certain receivables;*
- *Suncor's optimism about a gradual return to full operations in Libya and its assessment of the situation in Libya, including the impairment of net assets, the status of physical assets, and sustainability of production rates;*
- *Management's belief that Suncor will have the capital resources to fund its planned 2012 capital spending program of $7.5 billion and to meet current and long-term working capital requirements, and that, if additional capital is required, adequate additional financing will be available to Suncor in the debt capital markets at commercial terms and rates;*
- *Management's belief that a phased and flexible approach to existing and future growth projects should assist Suncor in maintaining its ability to manage project costs and debt levels;*
- *The company plans to maintain access to short-term commercial paper borrowing at competitive interest rates by keeping short-term debt at existing levels;*
- *Steve Williams assuming the role of CEO in May 2012;*
- *The company's expectations that the maximum weighted average term to maturity of its short-term investment portfolio will not exceed six months, and that all investments will be with counterparties with investment grade debt ratings; and*
- *Suncor's assessment of the impact of Bill C-13, which expects that, in future years, the legislation will decrease cash flow from operations by accelerating the payment of cash income taxes, but will not have a significant impact on net earnings.*

Forward-looking statements and information 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. Suncor's actual results may differ materially from those expressed or implied by its forward-looking statements, so readers are cautioned not to place undue reliance on them.

The financial and operating performance of the company's reportable operating segments, specifically Oil Sands, Exploration and Production, and Refining and Marketing, may be affected by a number of factors.

Factors that affect our Oil Sands segment include, but are not limited to, volatility in the prices for crude oil and other production, and the related impacts of fluctuating light/heavy and sweet/sour crude oil differentials; changes in the demand for refinery feedstock and diesel fuel, including the possibility that refiners that process our proprietary production will be closed, experience equipment failure or other accidents; our ability to operate our oil sands facilities reliably in order to meet production targets; the output of newly commissioned facilities, the performance of which may be difficult to predict during initial operations; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; our dependence on pipeline capacity and other logistical constraints, which may affect our ability to distribute our products to market; our ability to finance oil sands growth and sustaining capital expenditures; the availability of bitumen feedstock for upgrading operations, which can be negatively affected by poor ore grade quality, unplanned mine equipment and extraction plant maintenance, tailings storage, in situ reservoir and equipment performance, or the unavailability of third-party bitumen; inflationary pressures on operating costs, including labour, natural gas and other energy sources in oil sands processes; our ability to complete projects, including planned maintenance events, both on time and on budget, which could be impacted by competition from other projects (including other oil sands projects) for goods and services and demands on infrastructure in Fort McMurray and the surrounding area (including housing, roads and schools); risks and uncertainties associated with obtaining regulatory and stakeholder approval for exploration and development activities; changes to royalty and tax legislation and related agreements that could impact our business, such as our

current dispute with the Alberta Department of Energy in respect of the Bitumen Valuation Methodology Regulation; the potential for disruptions to operations and construction projects as a result of our relationships with labour unions that represent employees at our facilities; and changes to environmental regulations or legislation.

Factors that affect our Exploration and Production segment include, but are not limited to, volatility in crude oil and natural gas prices; operational risks and uncertainties associated with oil and gas activities, including unexpected formations or pressures, premature declines of reservoirs, fires, blow-outs, equipment failures and other accidents, uncontrollable flows of crude oil, natural gas or well fluids, and pollution and other environmental risks; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; adverse weather conditions, which could disrupt output from producing assets or impact drilling programs, resulting in increased costs and/or delays in bringing on new production; political, economic and socio-economic risks associated with Suncor's foreign operations, including the unpredictability of operating in Libya and the possibility that operations in Syria continue to be impacted by sanctions or political unrest; risks and uncertainties associated with obtaining regulatory and stakeholder approval for exploration and development activities; the potential for disruptions to operations and construction projects as a result of our relationships with labour unions that represent employees at our facilities; and market demand for mineral rights and producing properties, potentially leading to losses on disposition or increased property acquisition costs.

Factors that affect our Refining and Marketing segment include, but are not limited to, fluctuations in demand and supply for refined products that impact the company's margins; market competition, including potential new market entrants; our ability to reliably operate refining and marketing facilities in order to meet production or sales targets; the possibility that completed maintenance activities may not improve operational performance or the output of related facilities; risks and uncertainties affecting construction or planned maintenance schedules, including the availability of labour and other impacts of competing projects drawing on the same resources during the same time period; and the potential for disruptions to operations and construction projects as a result of our relationships with labour unions or employee associations that represent employees at our refineries and distribution facilities.

Additional risks, uncertainties and other factors that could influence financial and operating performance of all of Suncor's operating segments and activities include, but are not limited to, changes in general economic, market and business conditions, such as commodity prices, interest rates and currency exchange rates; fluctuations in supply and demand for Suncor's products; the successful and timely implementation of capital projects, including growth projects and regulatory projects; 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; actions by government authorities, including the imposition of taxes or changes to fees and royalties, and changes in environmental and other regulations; the ability and willingness of parties with whom we have material relationships to perform their obligations to us; the occurrence of unexpected events such as fires, equipment failures and other similar events affecting Suncor or other parties whose operations or assets directly or indirectly affect Suncor; the potential for security breaches of Suncor's information systems by computer hackers or cyberterrorists, and the unavailability or failure of such systems to perform as anticipated as a result of such breaches; our ability to find new oil and gas reserves that can be developed economically; the accuracy of Suncor's reserves, resources and future production estimates; market instability affecting Suncor's ability to borrow in the capital debt markets at acceptable rates; maintaining an optimal debt to cash flow ratio; the success of the company's risk management activities using derivatives and other financial instruments; the cost of compliance with current and future environmental laws; risks and uncertainties associated with closing a transaction for the purchase or sale of an oil and gas property, including estimates of the final consideration to be paid or received, 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 that are customary to transactions of this nature; 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 that is needed to reduce the margin of error and increase the level of accuracy; failure to realize anticipated synergies or cost-savings; and incorrect assessments of the values of assets acquired and liabilities assumed in the merger with Petro-Canada. The foregoing important factors are not exhaustive.

Many of these risk factors and other assumptions related to Suncor's forward-looking statements and information are discussed in further detail throughout the MD&A, including under the heading Risk Factors, and the company's 2011 AIF dated March 1, 2012 and Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission at www.sec.gov. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

QuickLinks

EXHIBIT 99-2

Management's Discussion and Analysis for the fiscal year ended December 31, 2011, dated February 23, 2012

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EXHIBIT 99-3

Consent of PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
111 5th Avenue SW, Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 (403) 509 7500
Facsimile +1 (403) 781 1825

CONSENT OF INDEPENDENT AUDITOR

We hereby consent to inclusion in this Annual Report on Form 40-F for the year ended December 31, 2011 and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021) and Form S-8 (File No. 333-161029), of Suncor Energy Inc., of our report dated February 23, 2012 relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in the Annual Report.

We also consent to reference to us under the heading "Interests of Experts" in the Annual Information Form incorporated by reference in this Annual Report on Form 40-F which is incorporated by reference in the Registration Statements referred to above.

"PricewaterhouseCoopers LLP"
Chartered Accountants
Calgary, Alberta
March 1, 2012

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EXHIBIT 99-3

Consent of PricewaterhouseCoopers LLP

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EXHIBIT 99-4

Consent of GLJ Petroleum Consultants Ltd.

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces of Canada

Dear Sirs

Re: Suncor Energy Inc.

We refer to the following reports (the "Reports") prepared by GLJ Petroleum Consultants Ltd. ("GLJ"):

- Reserves Assessment and Evaluation of In Situ Oil Sands Properties — Corporate Summary; and
- Reserves Evaluation and Resources Assessment of Oil Sands Mining Properties — Summary.

which provide GLJ's reports on proved and probable reserves evaluations pursuant to Canadian disclosure requirements of Suncor Energy Inc.'s Canadian mining and in-situ leases that were evaluated as at December 31, 2011.

We hereby consent to the use of our name, reference to and excerpts from the said Reports by Suncor Energy Inc. in its Annual Report on Form 40-F and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021) and Form S-8 (File No. 333-161029) of Suncor Energy Inc., of our Reports. In addition, we also consent to the use of our name, reference to and excerpts from the said Reports in Suncor Energy Inc.'s 2011 annual report to be filed with the securities regulatory authorities of each of the provinces of Canada.

We have read Suncor Energy Inc.'s Annual Information Form dated March 1, 2012 and the Form 40-F dated March 1, 2012 and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Reports or that are within our knowledge as a result of the services which we performed in connection with the preparation of the Reports.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

"GLJ PETROLEUM CONSULTANTS LTD."

Caralyn P. Bennett, P. Eng.
Vice-President, In Situ Oil Sands

Dated: March 1, 2012
Calgary, Alberta
CANADA

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EXHIBIT 99-4

Consent of GLJ Petroleum Consultants Ltd.
LETTER OF CONSENT

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EXHIBIT 99-5

Consent of Sproule Associates Limited and Sproule International Limited

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces of Canada

Dear Sirs:

Re: Suncor Energy Inc.

We refer to the following reports (the "Reports") prepared by Sproule Associates Limited ("Sproule Associates") and Sproule International Limited ("Sproule International"):

- Evaluation of the P&NG Reserves of Suncor Energy Inc. in the Newfoundland Offshore Areas;
- Evaluation of the P&NG Reserves of Suncor Energy Inc. in the North America Onshore Properties;
- Evaluation of the P&NG Reserves of Suncor Energy Inc., North Sea Properties; and
- Evaluation of the P&NG Reserves of Suncor Energy Inc., Other International Properties

which provide Sproule Associates' and Sproule International's reports on proved and probable reserves evaluations and reviews pursuant to Canadian disclosure requirements of Suncor Energy Inc.'s Canadian onshore and offshore conventional assets and international operations that were evaluated as at December 31, 2011.

We each hereby consent to the use of our name, reference to and excerpts from the said Reports by Suncor Energy Inc. in its Annual Report on Form 40-F and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021) and Form S-8 (File No. 333-161029) of Suncor Energy Inc., of our Reports. In addition, we each also consent to the use of our name, reference to and excerpts from the said Reports in Suncor Energy Inc.'s 2011 annual report to be filed with the securities regulatory authorities of each of the provinces of Canada.

We each have read Suncor Energy Inc.'s Annual Information Form dated March 1, 2011 and the Form 40-F dated March 1, 2012 and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Reports or that are within our knowledge as a result of the services which we performed in connection with the preparation of the Reports.

Sincerely,

Sproule Associates Limited and
Sproule International Limited

"Sproule Associates Limited" and
"Sproule International Limited"

Harry J. Helwerda, P.Eng., FEC
Executive Vice President and Director

Dated: March 1, 2012
Calgary, Alberta, Canada

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EXHIBIT 99-5

Consent of Sproule Associates Limited and Sproule International Limited
LETTER OF CONSENT

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EXHIBIT 99-6

CERTIFICATION

I, RICHARD L. GEORGE, certify that:

1. I have reviewed this annual report on Form 40-F of the Issuer;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this annual report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ RICHARD L. GEORGE

Richard L. George
Chief Executive Officer

DATE: March 1, 2012

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EXHIBIT 99-6

CERTIFICATION

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EXHIBIT 99-7

CERTIFICATION

I, BART W. DEMOSKY, certify that:

1. I have reviewed this annual report on Form 40-F of the issuer;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this annual report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ BART W. DEMOSKY

Bart W. Demosky
Chief Financial Officer

DATE: March 1, 2012

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EXHIBIT 99-7

CERTIFICATION

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EXHIBIT 99-8

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, RICHARD L. GEORGE, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ RICHARD L. GEORGE

Richard L. George
Chief Executive Officer
Suncor Energy Inc.

DATE: March 1, 2012

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EXHIBIT 99-8

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

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EXHIBIT 99-9

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, BART W. DEMOSKY, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ BART W. DEMOSKY

Bart W. Demosky
Chief Financial Officer
Suncor Energy Inc.

DATE: March 1, 2012

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EXHIBIT 99-9

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002