SUNCOR ENERGY INC.

Annual Information Form
Dated March 1, 2013

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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 arrangements, unless the context otherwise requires. References to the "Board of Directors" or the "Board" mean the Board of Directors of Suncor Energy Inc., unless the context otherwise indicates.

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 2012 audited Consolidated Financial Statements mean Suncor's audited Consolidated Financial Statements prepared in accordance with Canadian generally accepted accounting principles (GAAP), which is within the framework of International Financial Reporting Standards (IFRS), the notes and the auditors' report, as at and for each year in the two-year period ended December 31, 2012. References to our MD&A mean Suncor's Management's Discussion and Analysis, dated February 26, 2013.

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 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.

Brent is a blend of light, sweet crudes sourced from the North Sea used as a global price benchmark for internationally traded crude oil.

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**.

Western Canadian Select (WCS) is a heavy blended crude oil comprised primarily of conventional heavy oil or bitumen blended with diluent that is traded out of Hardisty, Alberta.

West Texas Intermediate (WTI) 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 production from **unconventional natural gas** formations, such as 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 holes 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.

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, usually drilled without the intention of being completed for production, which are geologically directed to obtain information pertaining to a specific geologic condition, such as **core hole drilling** on oil sands leases, or to measure the commercial potential (i.e. size and quality) of a discovery, such as **appraisal wells** for offshore discoveries.

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 SCO for the company's oil sands operations, or ii) crude oil and/or other components required in the production of refined petroleum product 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 PSC, 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 in the reservoir 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 water (converted to steam) required to produce one cubic metre of oil. A lower ratio indicates more efficient 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 SCO.

> **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 and nitrogen of, primary upgrading output to create sweet SCO 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	gigajoules
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 mcfe or mmcfe on the basis of one bbl to six mcf, and certain natural gas volumes to boe, mboe, or mmboe on the same basis. Any figure presented in mcfe, mmcfe, boe, mboe, or mmboe 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 kilometre = 0.62 miles
1 m^3 natural gas = 35.49 cubic feet	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.", referred to in this document as the "merger". 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 - 6th 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, 2012 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 holds the company's interest in the Syncrude joint arrangement.
Suncor Energy Oil and Gas Partnership	Canada	This partnership holds an interest in Suncor Energy Resources Partnership and Suncor Energy Ventures Partnership.
Suncor Energy Resources Partnership	Canada	This partnership holds certain upstream Canadian oil and gas assets.
Suncor Energy Joslyn Partnership	Canada	This partnership holds the company's working interest in the Joslyn joint arrangement.
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 Products Partnership	Canada	This partnership holds substantially all of the company's Canadian refining and marketing assets.
Suncor Energy Marketing Inc.	Canada	A subsidiary of Suncor Energy Products Inc. through which production from our upstream North American businesses is marketed. Through this subsidiary, we also administer Suncor's energy trading activities, market certain third-party products, procure crude oil feedstock and natural gas for our downstream business, and procure and market NGLs and LPG for our Canadian downstream business.
U.S. operations		
Suncor Energy (U.S.A.) Holdings Inc.	U.S.	A subsidiary of Suncor Energy Inc. that holds the majority of U.S. interests.
Suncor Energy (U.S.A.) Marketing Inc.	U.S.	A subsidiary of Suncor Energy (U.S.A.) Holdings Inc. that procures and markets third-party crude oil, in addition to procuring crude oil feedstock for the company's U.S. refining operations.
Suncor Energy (U.S.A.) Inc.	U.S.	A subsidiary of Suncor Energy (U.S.A.) Holdings Inc. that holds 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.
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.
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 U.A. that holds certain of our international interests.
Petro-Canada Palmyra B.V.	The Netherlands	A subsidiary of Petro-Canada (International) Holdings B.V. that holds the majority of our interests in Syria.
Suncor Energy Germany GmbH	Germany	A subsidiary of Petro-Canada (International) Holdings B.V. that holds the majority of our interests in Libya.
Suncor Energy Oil (North Africa) GmbH	Germany	A subsidiary of Suncor Energy Germany GmbH through which the majority of our Libya operations are conducted.

The company's remaining subsidiaries each accounted for (i) less than 10% of the company's consolidated assets as at December 31, 2012, and (ii) less than 10% of the company's consolidated revenues for the fiscal year ended December 31, 2012. 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 headquartered 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 conduct energy trading activities focused principally on the marketing and trading of crude oil, natural gas and byproducts.

Suncor has classified its operations into the following segments:

OIL SANDS

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

- **Oil Sands** operations refer to Suncor's wholly owned and operated mining, extraction, upgrading and in situ assets in the Athabasca oil sands. Oil Sands operations consist of:
  - **Oil Sands Base** operations include the Millennium and North Steepbank mining and extraction operations, 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 Suncor's tailings management (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. In Situ production is either upgraded by Oil Sands Base or blended with diluent and marketed directly to customers.
- **Oil Sands Ventures** assets include the company's interests in significant growth projects, including its 36.75% interest in the Joslyn North mining project, and two projects where Suncor is the operator, including its 40.8% interest in the Fort Hills mining project and its 51.0% interest in the Voyageur upgrader project. Oil Sands Ventures also includes the company's 12.0% interest in the Syncrude oil sands mining and upgrading operation.

EXPLORATION AND PRODUCTION

Suncor's Exploration and Production segment 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, which Suncor operates. Suncor also holds a 20.0% 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 its 26.69% interest in the Golden Eagle Area Development (Golden Eagle), both in the U.K. sector of the North Sea and both of which are not operated by Suncor. Suncor also holds interests in several exploration licences offshore the U.K. and Norway. Suncor owns, pursuant to EPSAs, working interests in the exploration and development of oilfields in the Sirte Basin in Libya. Suncor also owns, pursuant to a PSC, an interest in the Ebla gas development in the Ash Shaer and Cherrife areas in Syria. Due to unrest in Syria, the company has declared force majeure under its contractual obligations, and Suncor's operations in Syria have been suspended indefinitely.
- **North America Onshore** operations include Suncor's interests in a number of natural gas and conventional crude oil assets, primarily in Western Canada.

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, Québec, 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 Refining and Product Supply 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 marketing, supply and trading activities, and other activities not directly attributable to any other operating segment.

- **Renewable Energy** interests include six operating wind power projects across Canada and the St. Clair ethanol plant in Ontario.
- **Energy Trading** activities primarily involve the marketing, supply and trading of crude oil, natural gas and byproducts, and the use of midstream infrastructure and financial derivatives to optimize related trading strategies.
- **Corporate** activities include 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

2010

- **Disposition of non-core assets.** Subsequent to the merger with Petro-Canada in 2009, 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.
- **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.
- **Production commences in Syria.** Suncor achieved commercial production of natural gas from the Ebla gas 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 co-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 33.99%.
- **Transformation of downstream Marketing operations.** Suncor rebranded the majority of its 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 enters into joint arrangements with Total E&P.** In December, Suncor announced that it had entered into agreements with Total E&P Canada Ltd. (Total E&P) with respect to the restart of the Voyageur upgrader project, and the joint development of the Fort Hills and Joslyn North mining projects with the respective co-owners of these projects. These transactions closed in 2011 after receiving necessary regulatory approvals. Suncor sold to Total E&P a 49% interest in the Voyageur upgrader project and a 19.2% interest in the Fort Hills asset. In exchange, Suncor received cash proceeds and a 36.75% interest in the Joslyn asset.

2011

- **Exploration and Production segment created.** In January, Suncor announced organizational changes that included the former 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 the largest biofuels production facility in Canada.

- **Operations in Libya temporarily suspended.** In response to political unrest and sanctions in Libya in the first quarter of 2011, the operator of the company's joint operations in Libya shut in production. As a result, Suncor suspended all exploration activities and declared force majeure under its EPSAs. Sanctions in Libya were eventually lifted upon the transition to a new government, and the operator was able to restart production from all major producing fields in the first quarter of 2012.
- **Largest turnaround in Suncor history.** During the second quarter, the company completed the largest turnaround in the company's history at its Upgrader 2 facilities. The turnaround was completed safely and on time.
- **New wind farms commissioned.** In May, Suncor commissioned the eight-turbine, 20-MW Kent Breeze wind power project in southwest Ontario. In November, Suncor commissioned the 55-turbine, 88-MW Wintering Hills wind power project in southern Alberta.
- **Development of Golden Eagle approved.** In the third quarter, the field development plan for Golden Eagle in the U.K. sector of the North Sea 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 area at its Oil Sands Base operations. The opening of this new area enabled 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 ceased recording all production and revenue associated with its Syrian assets. Later, in 2012, the company received proceeds from risk mitigation instruments related to its Syrian assets, which are subject to a provisional repayment should operations in Syria resume.
- **Systems integration project completed.** 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

- **Steve Williams appointed as Chief Executive Officer.** In December 2011, Steve Williams, formerly Suncor's Chief Operating Officer (COO), was appointed president and a member of the company's Board of Directors, and assumed the role of Chief Executive Officer (CEO) in May 2012. Prior to becoming COO, Mr. Williams served as Executive Vice President, Oil Sands for four years where he was responsible for leading Suncor's Oil Sands operations through a significant period of growth. Mr. Williams replaced Suncor's long-standing CEO, Rick George, who retired in May after more than 20 years leading the company.
- **$\mathrm{TRO}_{\mathrm{TM}}$ operations underway.** Suncor completed its tailings management project. New infrastructure included pipes, pumphouses and fluid transfer barges that (a) pump tailings water from extraction plants to a sand placement area, (b) pump mature fine tailings from the sand placement area to a tailings pond for $\mathrm{TRO}_{\mathrm{TM}}$ treatment, and (c) pump treated water from tailings ponds back to extraction plants for use in production processes. Through the $\mathrm{TRO}_{\mathrm{TM}}$ process, mature fine tailings are converted more rapidly into a solid material suitable for reclamation. As a result of this new technology and the company's capital investment to reconfigure its tailing operations, Suncor has cancelled plans for five additional tailings ponds.
- **Off-station maintenance at East Coast Canada assets.** The Floating Production, Storage and Offloading (FPSO) vessels for both Terra Nova and White Rose were disconnected and transported to docking facilities for planned maintenance. The water injection swivel was replaced on the Terra Nova FPSO, while the propulsion system was repaired on the White Rose FPSO. The off-station maintenance program for Terra Nova also allowed the company to replace subsea infrastructure to help mitigate hydrogen sulphide (H_2S) issues.
- **Growth at Firebag.** Production from Firebag increased approximately 75% compared with 2011. In 2012, Firebag Stage 3 central processing facilities commissioned in the previous year reached design capacity approximately one year after first oil was brought on-stream. Stage 4 central processing facilities were commissioned in 2012, with first oil from Stage 4 wells brought on-stream in December. Once Stage 4 central processing facilities reach full capacity, total production from Firebag is expected to be approximately 180,000 bbls/d. There is significant integration between Firebag Stages 1 through 4, allowing operational flexibility to optimize production, maintenance, reliability and costs.
- **MNU commences operations.** The Millennium Naphtha Unit (MNU), which consists of a hydrogen plant and a naphtha hydrotreating unit, began operating at design rates. The company expects that the MNU will increase sweet SCO production capacity by approximately 10%, primarily through the new naphtha hydrotreating unit, and stabilize secondary upgrading processes by providing flexibility with respect to hydrogen production during planned or unplanned maintenance.
- **Oil Sands logistics infrastructure brought into service.** During 2012, the company brought into service the Wood Buffalo pipeline, which connects the company's Athabasca terminal at the base plant in Fort McMurray to other third-party pipeline infrastructure in Cheecham, Alberta, and the first two of four new storage tanks in Hardisty, Alberta, which will connect to the Enbridge mainline pipeline in 2013.

- **Hebron project receives sanction.** On December 31, 2012, the co-owners of the Hebron project located offshore Newfoundland and Labrador sanctioned the development plan that includes a concrete gravity-based structure (GBS) supporting an integrated topsides deck to be used for production, drilling and accommodations. Suncor has a 22.729% interest in the Hebron project. The estimated gross oil production capacity for Hebron is 150,000 bbls/d. Suncor's share of the project cost estimate provided by the project operator is approximately $3.2 billion. First oil is expected in late 2017.

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 in the Wood Buffalo region of northeast Alberta, involve numerous activities:

- **Mining and Extraction**

  After overburden is removed, open-pit mining operations use shovels to excavate oil sands bitumen ore, which is trucked to sizers and breaker units that reduce the size of the ore. Next, a slurry of hot water, sand and bitumen is created and 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 in extraction processes. 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 and other byproducts.

- **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 Oil Sands Base cogeneration unit, or provided by cogeneration units at Firebag.

- **Maintenance**

  In the normal course of operations, Suncor regularly conducts planned maintenance events at its 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 and Tailings**

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

  The extraction process produces tailings that are a mixture of water, clay, sand and residual bitumen. Suncor has developed a tailings management approach, known as TRO$_{TM}$, which involves converting mature fine tailings more rapidly into a solid material 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. TRO$_{TM}$ is expected to accelerate and improve the company's tailings management processes, eliminate the need for new tailings ponds at existing mining operations, 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, achieving first production in 1967. The original mining area is essentially depleted, and, for several years, bitumen was mined almost exclusively from the Millennium area, which began production in 2001. The company began mining from the North Steepbank area in 2011. During 2012, the company mined approximately 151 million tonnes of bitumen ore (2011 – 161 million tonnes). During 2012, Suncor averaged processing 266,200 bbls/d of mined bitumen in its extraction facilities (2011 – 287,100 bbls/d).

Upgrading

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

During 2012, Suncor averaged 276,700 bbls/d of upgraded (SCO and diesel) production, sourced from bitumen provided by both mining and extraction and in situ operations, and an additional 48,100 bbls/d of bitumen production (2011 – 279,700 bbls/d upgraded, 25,000 bbls/d bitumen).

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 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 produce bitumen from oil sands deposits that are too deep to be mined economically.

- **The SAGD process**

  The SAGD process requires drilling pairs of horizontal wells with one located above the other. To help reduce land disturbance and improve cost efficiency, well pairs are drilled from 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 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.

- **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 shipment, In Situ operations add diluent (naphtha) to the bitumen or transport it via an insulated pipeline.

- **Power and steam generation**

  Gas vapours recovered at central processing facilities are treated and used as fuel to power Once Through Steam Generators (OTSGs). Cogeneration units are energy-efficient systems, which use natural gas combustion to power turbines that generate electricity and steam used in SAGD operations. Excess electricity generation from cogeneration units is used at Oil Sands Base facilities or sold to the power grid.

- **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. In an effort to maintain bitumen supply, Suncor drills new wells from existing well pads or develops and constructs new well pads.

In Situ Assets

Firebag

Production from Suncor's Firebag operations commenced in 2004 with Firebag Stage 1, followed by the completion and start of operations for Firebag Stage 2 in 2006 and Firebag Stage 3 in 2011. With the completion of the majority of construction, and start of operations for Firebag Stage 4 in 2012, Suncor's Firebag complex consists of four central processing facilities with total bitumen processing capacity of approximately 180,000 bbls/d. Actual production from Firebag may vary based on steaming and ramp-up periods for new wells, planned and unplanned maintenance, reservoir conditions and other factors.

As at December 31, 2012, Firebag included nine well pads with 109 well pairs either producing or on initial steam injection and 18 producing infill wells. Central processing facilities have been designed to be flexible as to which well pads supply bitumen, and steam generated at the various facilities can be used at multiple well pads. In addition, Firebag includes five cogeneration units that generate steam and that are capable of producing 425 MW of electricity that is used to power 13 OTSGs.

During 2012, Firebag operations averaged production of 104,000 bbls/d of bitumen (2011 – 59,500 bbls/d), approximately 78% (2011 – 90%) of which was upgraded by Oil Sands Base operations. As at December 31, 2012, the cumulative SOR at Firebag was 3.4 (2011 – 3.3). As production increases, the SOR for Firebag is expected to decrease.

MacKay River

Production from MacKay River commenced in 2002. As at December 31, 2012, MacKay River included six well pads with 71 well pairs either producing or on initial steam injection. The MacKay River central processing facilities have bitumen processing capacity of approximately 30,000 bbls/d. A third party owns the on-site cogeneration unit that is used to generate steam and power four OTSGs, which Suncor operates under a commercial agreement.

Suncor has regulatory approval for additional bitumen production from MacKay River and adjacent Dover lands, and is currently evaluating an expansion to increase bitumen processing capacity through additional central processing facilities. The company has commenced a debottlenecking project of existing central processing facilities that is expected to increase existing bitumen processing capacity to approximately 38,000 bbls/d by 2015.

During 2012, MacKay River operations averaged production of 27,000 bbls/d of bitumen (2011 – 30,000 bbls/d), approximately 7% (2011 – 30%) of which was upgraded by Oil Sands Base operations. The decrease in this percentage was due mainly to higher production from Firebag being upgraded. As at December 31, 2012, the cumulative SOR at MacKay River was 2.5 (2011 – 2.5).

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 exploratory drilling programs on a year-to-year basis. In 2012, Suncor drilled 27 core holes (2011 – 22 core holes) at Meadow Creek.

Oil Sands Ventures – Assets and Operations

Syncrude

Suncor holds a 12% interest in the Syncrude joint arrangement, located near Fort McMurray, which includes mining operations at Mildred Lake North and Aurora North. Syncrude also has regulatory approval to develop the Aurora South oil sands mining leases. In 2012, Syncrude owners announced a plan to develop two mining areas adjacent to the current mine, subject to final sanctioning and regulatory approvals, which would consequently extend the life of Mildred Lake by approximately ten years. The plan proposes to use existing mining and extraction facilities. Syncrude expects to make regulatory applications for these areas in 2014.

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 pipeline systems, similar to those at Oil Sands Base. Extraction and upgrading technologies at Syncrude are similar to those used at Oil Sands Base, with the exception that Syncrude uses a fluid coking process that involves the continuous thermal cracking of the heaviest hydrocarbons. 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.

Syncrude produces a single sweet synthetic light crude product. Marketing of this product is the responsibility of the individual co-owners.

Land reclamation activities are similar to those at Oil Sands Base; however, tailings management processes are different. Syncrude's 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 2012, Suncor's share of Syncrude production averaged 34,400 bbls/d (2011 – 34,600 bbls/d).

Fort Hills, Joslyn, and the Voyageur upgrader

During the first quarter of 2011, Suncor completed transactions with Total E&P, which brought Total E&P into the Voyageur upgrader project, increased its working interest in the Fort Hills oil sands mining project and brought Suncor into the Joslyn North oil sands mining project.

- Fort Hills is the oil sands mining area comprising leases on the east side of the Athabasca River, north of Oil Sands Base operations. Preliminary designs for the Fort Hills mining project 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 with Petro-Canada, 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 co-owners of Fort Hills had completed design basis memorandum engineering in 2008, but deferred a final investment decision as a result of the global economic downturn. Subsequent to completing the transactions with Total E&P, the Fort Hills project was restarted. The scoping study and design basis memorandum engineering have been updated and the project has now moved into the final phase of front-end engineering.
- Joslyn is the oil sands mining area comprising leases southwest of Fort Hills and on the west side of the Athabasca River. Total E&P is the operator. Preliminary designs for the Joslyn North mining 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.
- Suncor began design work for the Voyageur upgrader in 2004, but subsequently placed the project into safe mode in January 2009 as a result of the global economic downturn, at which time construction was approximately 15% complete. Subsequent to the transactions with Total E&P, the Voyageur upgrader project team has engaged in site preparation activities and assessed the condition of assets.

As previously announced, Suncor has been working with its respective partners to undertake detailed reviews of each of its planned Oil Sands Ventures growth projects, focusing on cost and quality with a view to generating long-term value for shareholders.

With respect to the Fort Hills mining project, the partners expect a sanction decision to occur in the second half of 2013. Suncor plans to provide an update on the targeted timing for a sanction decision on the Joslyn project when available.

Suncor's view is that the economic outlook for the Voyageur upgrader project is challenged. Suncor and its partner continue to work diligently towards determining an outcome for the project. The partners have been considering options for the project, including the implications of cancellation or indefinite deferral. No formal decisions regarding the project have been made, and the partners continue to work toward a decision by the end of the first quarter of 2013. The Voyageur upgrader project cannot be sanctioned to proceed without the approval of both partners and, in the case of Suncor, Suncor's Board of Directors. In the interim, Suncor and its partner have agreed to minimize expenditures on the project pending a decision.

Given the challenging economic outlook for the Voyageur upgrader project, at the end of 2012, the company performed an impairment test and recorded an impairment charge.

New Technology

Suncor is involved in testing several technologies through numerous operated and non-operated pilot projects. These pilot projects evaluate potential enhancements to existing mining and SAGD operations or potential new technologies targeted at improving capital efficiency and lowering operating costs.

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 Edmonton refinery; or c) selling diluted bitumen directly to third parties. Increased bitumen sales may also be required during outages of upgrading facilities or interruptions in pipeline systems. During 2012, approximately 63% or 82,900 bbls/d (2011 – 73% or 64,600 bbls/d) of In Situ bitumen production was processed by Oil Sands Base upgrading facilities.

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	2012		2011	
	mbbls/d	% operating revenues	mbbls/d	% operating revenues
Sweet SCO (including Syncrude) and diesel	152.7	47	144.4	44
Sour SCO and bitumen	205.6	48	194.6	45
Non-proprietary, byproducts and other operating revenues (1)	n/a	5	n/a	11
	358.3		339.0	

(1) Operating revenues include sales of non-proprietary volumes, primarily third-party diluent that is purchased to support sales of bitumen when the company is unable to meet diluent demands internally.

In the normal course of business, Suncor enters into long-term strategic sales 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 operations is gathered into Suncor's 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. 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, including Suncor, or transferred onto the Enbridge Mainline system or the TransMountain Pipeline system.
- SCO and diluted bitumen are transported to Cheecham, Alberta, on the Enbridge Athabasca Pipeline or the Enbridge Wood Buffalo Pipeline. From Cheecham, the Enbridge Athabasca Pipeline continues to Hardisty, Alberta.
- SCO also reaches Edmonton via the Enbridge Waupisoo Pipeline, originating at Cheecham.

From Hardisty, where Suncor owns storage capacity with additional 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 system, 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 and bitumen. Natural gas is delivered to Oil Sands Base and In Situ facilities via the Nova Gas Transmission Limited (NGTL) pipeline system. Suncor also transports natural gas to Oil Sands Base facilities on the company-owned and operated Albersun Pipeline, which extends approximately 300 km south of 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.

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 2012, Oil Sands royalties (excluding Syncrude) were approximately 6% (2011 – 7%) of Oil Sands operating revenues (excluding Syncrude), excluding non-proprietary sales and sales of byproducts. In 2012, Suncor incurred royalties on Syncrude operations averaging approximately 6% of Syncrude operating revenues before royalties (2011 – 8%).

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 2012, Suncor incurred royalties at Oil Sands Base mining operations at a rate of 30% of R – C (2011 – 30% of R – C).

In November 2008, the Alberta government and the co-owners of Syncrude 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 will continue paying the greater of 1% gross revenue, or 25% of net revenue, until the end of 2015. For 2012, the royalty rate was 25% of net revenue (2011 – 25%). 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 part of the royalty project. In addition, the co-owners of Syncrude 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 that determine the valuation of bitumen for royalty purposes. The Crown notified Suncor that the BVM would apply to Oil Sands Base mining operations for purposes of the Suncor RAA (Suncor BVM). In 2009, Suncor provided notice to the Crown that the Suncor BVM was non-compliant with the Suncor RAA. In December 2010, the Alberta Minister of Energy notified Suncor of a modification to the Suncor BVM, providing for bitumen quality adjustments not previously recognized and adjustments for transportation. For the years 2009 through 2012, Suncor's royalties expense for Oil Sands Base mining operations were calculated based on these adjustments. Suncor has sent a further non-compliance notice to the Crown dated January 2011 stating that the quality adjustment remains non-compliant with the Suncor RAA (the transportation adjustment is not disputed). 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 arbitration is currently ongoing.

The co-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. Revenues used in royalties formulas are driven primarily by benchmark prices for WCS, while sliding-scale percentages in royalty formulas depend on 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 revenues exceed its cumulative costs, including an annual investment allowance (the post-payout phase). In 2012, Suncor incurred minimum royalties at a rate of 6% of R for MacKay River (2011 – 34% of R – C) and royalties averaging 6% of R for Firebag (2011 – 6%), which continues in the pre-payout phase. The royalty rate for MacKay River was lower in 2012, due primarily to lower benchmark prices for WCS.

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 extensions, and exploration drilling for new opportunities. Suncor is the only company in this region with interests in every field currently in production.

Terra Nova

The Terra Nova oilfield is approximately 350 km southeast of St. John's. 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 an 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, 2012, there were 28 wells: 16 oil production wells, nine water injection wells and three gas injection wells. In 2012, Suncor's share of Terra Nova production averaged 8,800 bbls/d (2011 – 16,200 bbls/d). Terra Nova was offline for approximately 27 weeks in 2012 as part of a dockside planned maintenance program to replace the FPSO water injection swivel and install subsea infrastructure to help mitigate H_2S issues. Production from the largest of three drill centres resumed subsequent to the completion of dockside maintenance late in 2012. Production from a second drill centre resumed in February 2013. The third drill centre is expected to be reconnected in the third quarter of 2013, when damaged flow lines can be replaced.

Current development plans for Terra Nova include a production well and a water injection well that the company anticipates will add production and mitigate natural declines from the reservoir. In addition, the company plans to drill a development well in the West Flank area of the oilfield during 2013.

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 GBS that sits on the ocean floor, and has gross production capacity of 230,000 bbls/d and oil storage capacity of 1,300,000 bbls. Actual production levels are lower, reflecting current reservoir capability and natural declines. Hibernia commenced production in November 1997. At December 31, 2012, there were 60 wells in operation (including those in the HSEU): 36 oil production wells, 14 single-zone water injection wells, five dual-zone water injection wells and five gas injection wells. In 2012, Suncor's share of Hibernia production averaged 26,100 bbls/d (2011 – 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 in 2010 between the Hibernia co-owners and the Government of Newfoundland and Labrador 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 production wells and five water injection wells in a subsea, excavated drill centre, known as a glory hole. The number of production and injection wells required may be revised as the development proceeds and uncertainties about reservoir capability are resolved. Production from the HSEU is not expected to reach higher rates until the planned water injection wells are completed.

White Rose and the White Rose Extensions

White Rose, the third oilfield development offshore Newfoundland, is approximately 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, 2012, there were 31 wells in operation (including the White Rose Extensions): 14 oil production wells, 14 water injection wells and three gas storage wells. The White Rose FPSO was offline for approximately 15 weeks in 2012 for a planned off-station maintenance program. In 2012, Suncor's share of White Rose production averaged 11,600 bbls/d (2011 – 18,500 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 co-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, including completion of one production well in 2012. Development of the West White Rose field is expected to be divided into two stages. The first stage was approved in 2010 and first oil was achieved in 2011 with the completion of the first production well. A water injection well to support this production well was completed in 2012. Evaluations for the second stage of development are being conducted by the White Rose co-owners with a focus on two potential options: (i) a subsea development (similar to the base field and North Amethyst); or (ii) a fixed drilling platform constructed with reinforced concrete. The co-owners have not made any decisions and either option requires regulatory approval.

Hebron

Discovered in 1980, the Hebron oilfield is located 340 km southeast of St. John's. The project is operated by ExxonMobil Canada Properties. On December 31, 2012, the Hebron co-owners announced project sanction. Development of the Hebron project includes the construction of a concrete GBS that supports an integrated topsides deck to be used for production, drilling and accommodations. Development plans include 1,200,000 bbls of oil storage capacity and 52 well slots with a gross oil production capacity of 150,000 bbls/d (net 34,000 bbl/d to Suncor). Suncor's share of the project cost estimate provided by the project operator is approximately $3.2 billion. First oil is expected in late 2017.

Other Assets

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

Suncor continues to pursue opportunities offshore Newfoundland and Labrador. The company holds interests in 50 other significant discovery licences and seven 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. 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. At December 31, 2012, there were 44 wells: 32 oil and gas production wells and 12 water injection wells. In 2012, Suncor's share of Buzzard production averaged 48,000 boe/d (2011 – 42,900 boe/d).

In 2012, Buzzard drilled four oil and gas development wells and an exploration well in the Northern Terrace area of the oilfield. The company is currently evaluating results from this exploration well.

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 Area Development – North Sea

During 2011, Golden Eagle received regulatory approval from the U.K. Department of Energy and Climate Change and sanction from the project's co-owners. This development is approximately 20 km north of the Buzzard oilfield and consists of the unitization of the Peregrine, Hobby and Golden Eagle discoveries completed from 2007 to 2009, and the Solitaire area, which received regulatory approval to be added to the development plan in 2012. 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 21 development wells. The development plan for Golden Eagle in 2013 includes the installation of platform jackets and the wellhead topside, and the start of development drilling. 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 Golden Eagle co-owners also hold adjacent exploration licences and continue to explore the region.

Other Assets – North Sea

Other Suncor exploration initiatives in the North Sea include:

- Beta prospect (Norway) – Suncor is the operator for the PL375 and PL375b licences, in which it has a 65% interest. 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 drilled a second appraisal well in 2012, but did not encounter hydrocarbons. The company will continue to evaluate the Beta discovery with the planned acquisition of new seismic data in 2013 and further appraisal drilling in 2014.
- Butch prospect (Norway) – During 2011, the operator for the PL405 licence, in which Suncor has a 30% interest, drilled an exploration well resulting in a discovery, followed by a sidetrack well to assess the lateral extent of the hydrocarbons. Early in 2012, a second sidetrack well drilled in this prospect was abandoned before reaching its intended depth, due to well instability. The operator, Centrica plc, intends to drill two additional exploration wells in 2013.
- Romeo prospect (U.K.) – During the second half of 2012, the company was the operator for an exploration well drilled in Block 30/11c, in which Suncor has a 57.857% interest; the company is currently evaluating drilling results. The joint well was drilled to comply with work commitments for the 30/11c licences held by Suncor and its co-owners, and the 29/15 licence held by another party.
- Scotney prospect (U.K.) – In 2013, Suncor will act as operator for a planned exploration well in Block 20/05b, in which it has a 32.86% interest. This well is being drilled to comply with a work commitment for the licence.

Suncor continues to pursue opportunities in the North Sea. The company holds interests in 29 exploration licences in the U.K. and Norwegian sectors of the North Sea.

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 costs 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 2012, Suncor's share of production in Libya averaged 41,500 bbls/d (2011 – 12,100 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 operation, 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 early 2012, production had restarted in all major producing fields and the company exited force majeure under its contractual obligations, including with respect to exploration activities.

As part of its contractual obligations under the EPSAs, Suncor will act as operator for an exploration program with an estimated remaining cost of US$275 million as at December 31, 2012. Suncor is working to restart exploration activities early in 2013 and is currently negotiating with the NOC around the period of force majeure under its EPSAs and the amount of time that Suncor has to fulfill its exploration commitment under its EPSAs.

As a result of the merger, the company assumed the remaining obligation for a signature bonus relating to Petro-Canada's ratification of the EPSAs in 2008. As at December 31, 2012, the undiscounted value of Suncor's remaining obligation is US$86 million, which is expected to be paid over the next three years.

Syria

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. In 2011, Suncor's share of production in Syria averaged 17,600 boe/d. Since this time, Suncor has not been able to monitor the status of any of its assets in the country, including whether certain facilities have suffered damages.

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 co-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.

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. The company has a contracted volume of 80 mmcf/d. Natural gas is delivered into the Syrian national gas grid for domestic electrical power generation. The Ebla development also includes three wells producing crude oil, which is sold to the GPC.

In 2012, the company recorded an impairment charge against its Syrian assets as a result of the uncertainty about the company's future in the country. Later in the year, the company received proceeds from risk mitigation instruments related to its Syrian assets, which are subject to a provisional repayment should operations in Syria resume.

North America Onshore – Assets and Operations

The North America Onshore business explores for, develops and produces natural gas, NGLs, crude oil and byproducts in Western Canada. After the merger with Petro-Canada, the strategy for this business focused on liquids-rich and unconventional sources, and, as a result, the company divested a number of non-core assets in this business area throughout 2010 and early 2011.

Given the vast amount of natural gas brought on-stream in North America by recent advances in shale gas technology, natural gas producers in North America continue to face relatively low gas prices. Suncor continues to focus on the profitability of this business, including increasing activity in unconventional areas, such as the Cardium oil formation in central Alberta and the Montney formation in northeast B.C.

In support of the company's focus on long-term profitable growth through its core assets, combined with a view that market conditions are improving, Suncor continues to explore opportunities to divest non-core properties, and will pursue opportunities that meets its financial objectives.

In 2012, Suncor's share of production from its North America Onshore properties was 323 mmcfe/d (2011 – 388 mmcfe/d). During 2012, the company shut in production from fields in southwest Alberta and northeast B.C. in response to low natural gas prices and the closure of a third-party gas processing facility, which contributed approximately 25 mmcfe/d of production in 2011. In addition, the company divested non-core assets during 2011 that contributed production of approximately 14 mmcfe/d in 2011. In 2012, natural gas represented 90% of production (2011 – 92%), with crude oil and NGL production representing the remainder. North America Onshore also earns operating revenues from sulphur, a byproduct of processing operations.

Operations in 2012 primarily focused on multiple geological zones throughout Western Canada. The business is structured with the following asset areas:

Zone / Area	Primary Focus	2012 mmcfe/d	2011 mmcfe/d
Northeast B.C.	Montney, Triassic and Slave Point	83	113
Southeast Alberta	Sweet, dry gas	62	70
Foothills – western Alberta, portions of northeast B.C.	Mississippian sour gas	130	161
Plains – western Alberta	Cardium oil, Cretaceous gas	48	44
Total		323	388

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

Natural gas extracted from the wellhead requires further processing. In Western Canada, Suncor currently 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 various working interests in other natural gas processing plants and field gathering facilities operated by other oil and natural gas companies. The following table shows Suncor's working interest ownership and the licensed capacity of operated processing plants as at December 31, 2012.

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. 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 Alliance firm capacity enables Suncor to deliver natural gas from B.C. to Illinois markets. The GTN firm capacity enables Suncor to deliver natural gas to the Pacific Northwest and California markets. Refer to the Forward Contracts and Transportation obligations section of this AIF for more information regarding Suncor's capacity on the Alliance Pipeline system and GTN.

Conventional crude oil production from North America Onshore assets is shipped on pipelines operated by independent pipeline companies. Suncor currently has 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 is sold to our Energy Trading business, which then markets the products to customers under direct sales 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 Libya, hydrocarbon production is marketed by the NOC on behalf of Suncor. In Syria, prior to the suspension of operations, the company entered into purchase and sale agreements with the Syrian government for all hydrocarbon production from the Ebla project.

For each of the Exploration and Production segment's operations, and for the Exploration and Production segment in total, the following table provides information on average sales volumes for principal products and the corresponding percentage of operating revenues for 2012 and 2011.

	2012		2011	
Sales Volumes	mboe/d	% operating revenues	mboe/d	% operating revenues
East Coast Canada				
Crude oil	46.7	33	59.0	46
International				
Crude oil and NGLs	88.5	59	62.4	38
Natural gas	1.0	1	14.0	4
North America Onshore				
Crude oil and NGLs	5.6	3	5.1	3
Natural gas	48.3	4	59.6	9
Total Exploration and Production				
Crude oil and NGLs	140.8	95	126.5	87
Natural gas	49.3	5	73.6	13

Royalties

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 2012, Terra Nova royalties averaged 36% of gross revenue (2011 – 32%).

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 2012, Hibernia (including the HSEU) royalties and NPI combined to average 35% of gross revenue (2011 – 37%).

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. The tier two royalty, equal to 10% of net revenue, became payable in 2008. The royalty for production from the White Rose Extensions 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 2012, total White Rose royalties averaged 12% of gross revenue (2011 – 14%).

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%. Royalties for NGLs are based on a combination of reference prices determined by the Alberta government and flat 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 Alberta 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 2 000 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.

In Alberta, 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 natural gas and NGL gross royalties payable.

Royalties for Suncor's North America Onshore production in B.C. 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 revenues.

In B.C., 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 2012, royalties for North America Onshore production averaged 7% of gross revenue (2011 – 11%).

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

The Montreal refinery has a crude oil capacity of 137,000 bbls/d, processing 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 feedstock. 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 via the Portland-Montreal Pipeline.

Production yield from the Montreal refinery includes gasoline, distillate, asphalt, heavy fuel oil, petrochemicals and solvents, which are distributed primarily across Quebec and Ontario. The Montreal refinery also produces feedstock for Suncor's 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 from 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 Mainline and Lakehead pipeline systems. Suncor procures conventional crude oil feedstock primarily from Western Canada, but periodically supplements supply with purchases from the U.S. and other countries.

Production yield from the Sarnia refinery includes gasoline, distillate 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 products into the U.S.

To meet the demands of Suncor's marketing network in Eastern North America, the company also purchases gasoline and distillate from other refiners. Suncor enters into reciprocal exchange arrangements with other refiners in Eastern North America, primarily for gasoline and distillate, as a means of minimizing transportation costs and balancing product availability. Specialty products, such as asphalt 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 paraxylene, which is used by customers to manufacture polyester textiles and plastic bottles. Paraxylene production was approximately 360,000 metric tons in 2012. 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. In 2012, the plant produced approximately 800 million litres of lubricant base stocks. Feedstock for the lubricants facility comes from Suncor's Montreal refinery and other purchase contracts.

Western North America

Effective January 1, 2013, Suncor increased the nameplate capacity of the Edmonton refinery to 140,000 bbls/d from 135,000 bbls/d, due to demonstrated reliability and continuous improvement in operating efficiency. The Edmonton refinery has the potential to run entirely on feedstock 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 co-owners' share of production) and other producers from the Athabasca and Cold Lake regions of Alberta. The refinery can process approximately 35,000 bbls/d of blended feedstock (comprised of 25,000 bbls/d of bitumen and 10,000 bbls/d of diluent) and process approximately 50,000 bbls/d of sour SCO. The refinery can also process approximately 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 distillate, 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.

The Commerce City refinery has a crude oil capacity of 98,000 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, distillate and asphalt. The majority of the refined products 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 the supply and demand balance in the Vancouver area, Suncor imports and exports finished products through its Burrard distribution terminal located on the west coast of B.C. 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 tables summarize the crude feedstock, utilizations and production yield mix for Suncor's refineries for the years ended December 31, 2012 and 2011. Refinery utilizations include the impacts of planned and unplanned maintenance events.

Average Daily Crude Throughput (mbbls/d, except as noted)	Montreal 2012	Montreal 2011	Sarnia 2012	Sarnia 2011	Edmonton 2012	Edmonton 2011	Commerce City 2012	Commerce City 2011
Oil Sands Base sweet synthetic	—	—	14.5	11.4	47.6	12.3	0.2	—
Oil Sands Base sour synthetic	—	—	22.7	25.2	49.9	41.2	8.3	7.7
Other synthetic	—	—	8.3	12.6	39.2	41.9	—	—
East Coast Canada light conventional [1]	21.6	23.0	—	—	—	—	—	—
Other light conventional	84.8	82.3	0.8	3.2	0.6	—	60.2	67.0
Sour conventional	4.7	10.2	22.2	18.6	—	—	—	—
Heavy conventional	18.0	15.3	—	—	0.6	20.4	27.0	16.0
Total	129.1	130.8	68.5	71.0	137.9	115.8	95.7	90.7
Utilization [2] (%)	94	101	81	83	102	86	98	98

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

(2) Utilization rates for Edmonton are determined based on refinery capacity (135,000 bbls/d), in effect prior to January 1, 2013. Utilization rates for 2011 for Montreal and Commerce City are determined based on refinery capacities in effect prior to January 1, 2012 (Montreal – 130,000 bbls/d, Commerce City – 93,000 bbls/d).

Refined Petroleum Production Yield Mix (%)	Montreal 2012	Montreal 2011	Sarnia 2012	Sarnia 2011	Edmonton 2012	Edmonton 2011	Commerce City 2012	Commerce City 2011
Gasoline	41	40	39	44	43	46	47	51
Distillate	35	34	46	42	52	50	34	36
Other	24	26	15	14	5	4	19	13

Distribution Terminals and Pipelines

Suncor owns and operates 13 major refined products terminals across Canada (including terminals adjacent to refineries) 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 the Refining and Marketing segment'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, Wyoming

Operations – Marketing

Suncor's retail service station network operates nationally in Canada under the Petro-Canada$_{TM}$ brand. As at December 31, 2012, the Petro-Canada$_{TM}$ retail service station network consisted of 1,458 outlets across Canada. In addition to marketing through proprietary retail outlets, refined products are marketed through independent dealers and joint arrangements. Suncor's Canadian retail network had annual sales of gasoline motor fuels averaging approximately 4.8 million litres per site in 2012 (2011 – 4.9 million litres per site) and attracted an estimated 17% share (2011 – 18% share) of the national retail market (based on data available from Statistics Canada for the period from January to October 2012). The decline in market share in 2012 primarily reflects increased competition.

Suncor's Colorado retail network consists of 44 owned outlets and product supply agreements with a larger network of Shell®-branded sites and Phillips 66®-branded sites in Colorado.

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

Suncor's wholesale operations sell refined 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 refined 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 the Refining and Marketing segment's operating revenues for the years ended December 31, 2012 and 2011.

Locations	As at December 31 2012	2011
Retail Service Stations – Canada		
Petro-Canada$_{TM}$-branded	1 458	1 456
Sunoco$_{TM}$-branded	7	9
	1 465	1 465
Retail Service Stations – Colorado		
Shell®-branded retail service stations	38	38
Phillips 66®-branded retail service stations	6	6
	44	44
Wholesale Cardlock Sites – Canada		
Petro-Canada$_{TM}$-branded cardlock sites (PETRO-PASS)	246	245

Sales Volumes	2012		2011	
	thousands of m^3/d	% operating revenues	thousands of m^3/d	% operating revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	19.8		20.9	
Western North America	20.4		18.8	
	40.2	47	39.7	45
Distillate (includes diesel and heating oils, and aviation jet fuels)				
Eastern North America	12.0		12.8	
Western North America	19.0		17.6	
	31.0	39	30.4	41
Other (includes heavy fuel oil, asphalt, lubricants, petrochemicals, other)				
Eastern North America	9.8		9.8	
Western North America	4.6		3.2	
	14.4	14	13.0	14
	85.6		83.1	

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, which provide 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.

Renewable Energy

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. The 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 2012, the plant produced 412.5 million litres of ethanol (2011 – 378.4 million litres).

In addition, Suncor's renewable energy interests include six wind power projects in operation. Suncor's wind farms 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. Suncor continues to evaluate new opportunities to build its renewable energy portfolio with potential wind power project sites that are in various stages of the evaluation process. The following table summarizes Suncor's wind power projects.

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

SUNCOR EMPLOYEES

The following table shows the distribution of employees among Suncor's business units and corporate office:

As of December 31	2012	2011
Oil Sands	6 015	5 464
Exploration and Production	719	768
Refining and Marketing	3 175	3 161
Corporate, Energy Trading and Renewable Energy	4 023	3 633
Total	13 932	13 026

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 34% of the company's employees were covered by collective bargaining agreements at the end of 2012. 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 3,300 employees supporting the company's Oil Sands operations is in force and expires in May 2013. The company is in the process of negotiating with the CEP for approximately 800 employees in the company's refinery, lubricants, natural gas, and terminal operations, for whom collective agreements expired in January 2013. A collective agreement with the CEP representing approximately 60 employees for the Terra Nova facility will expire in September 2013. A collective agreement with the United Steel Workers Union representing approximately 250 employees at the Commerce City refinery 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 2015.

SIGNIFICANT POLICIES

Suncor has a Standards of Business Conduct Code (the Code), which applies to Suncor's directors, officers, employees and contract workers. 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, harassment, 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 Suncor's 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. 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 Peoples to develop a thriving energy industry that allows Aboriginal communities to be vibrant, diversified and sustainable. The policy provides a consistent approach to the company's relationships with Canada's Aboriginal Peoples and outlines Suncor's responsibilities and commitments, and is intended to guide Suncor's business decisions on a day-to-day basis. Suncor is committed to working closely with Canada's Aboriginal Peoples and communities to build and maintain effective, long-term and mutually beneficial relationships. The policy makes it clear that responsible development takes into account Aboriginal issues and concerns about the effects, positive and negative, of energy development on communities and their traditional and current uses of lands and resources.

Suncor 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 reflects Suncor's belief 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.

The aforementioned policies are available on the company's intranet and external website and additional workshops and training sessions are conducted as warranted throughout the year. In addition, information regarding the policies is provided for employees primarily though feature articles on the company's intranet or employee newsletter. The Aboriginal policy has Cree and Dene audio translations. Regular training is provided for employees and contract workers whose roles require interaction with the respective stakeholder group.

In 2012, Suncor developed a social risk assessment tool subsequent to which social risk assessments commenced on certain new initiatives or, where warranted, due to significant changes to projects. The company continues to evaluate the process and revise the tools as needed. Regarding the EH&S policy, the Annual President's Operational Excellence Awards, which honour employees and contractors who demonstrate an exceptional commitment to health and safety, highlight progress on safety initiatives and provide educational opportunities for all employees. These significant policies are reviewed annually.

Date of Statement

The Statement of Reserves Data and Other Oil and Gas Information outlined below is dated March 1, 2013, with an effective date of December 31, 2012. The preparation date of the information is as of February 20, 2013.

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, 2012, 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 Libya (Other International), is based upon evaluations conducted by Sproule Associates Limited or Sproule International Limited (collectively, Sproule) with an effective date of December 31, 2012, 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.

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 revenues 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 net 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. Net Present Value of Future Net Revenues Before or After Income Taxes means respectively, the net present value of future net revenue before or after deducting future income tax expense in accordance with NI 51-101. 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 discussion 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 and reservoir fluid properties 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 PSCs. Regulatory changes, including royalty regimes and environmental regulations, cannot be predicted but may have positive or negative effects on reserves. Future technology improvements would be expected to have a favourable impact on the economics of reserves development and exploitation, and therefore result in an increase to reserves.

While the above factors, and many others, can be considered, certain judgments and assumptions are always required. As new information becomes available, these areas are reviewed and revised accordingly. For example, estimated SCO reserves presented under In Situ represent the company's forecast for its capacity available to upgrade bitumen from In Situ operations, mainly during later years when Mining reserves are eventually depleted. Actual SCO production from In Situ bitumen may vary from these forecasts due to unplanned maintenance, higher production capacity from mining and extraction operations, or changes in the company's overall Oil Sands development strategy, including with respect to planned upgrading capacity.

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.

Oil and Gas Reserves Tables and Notes

Summary of Oil and Gas Reserves(1)(2)(3)
as at December 31, 2012
(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	1 958.1	1 704.2	—	—	—	—	—	—	—	—	1 958.1	1 704.2
In Situ	171.5	163.0	179.2	163.2	—	—	—	—	—	—	350.7	326.2
East Coast Canada	—	—	—	—	44.1	33.3	—	—	—	—	44.1	33.3
North America Onshore	—	—	—	—	11.1	9.7	711.5	616.7	7.3	5.2	137.0	117.7
Total Canada	2 129.6	1 867.2	179.2	163.2	55.2	43.0	711.5	616.7	7.3	5.2	2 489.9	2 181.4
North Sea	—	—	—	—	78.3	78.3	2.4	2.4	0.2	0.2	78.9	78.9
Other International	—	—	—	—	104.0	38.0	—	—	—	—	104.0	38.0
Total Proved Developed Producing	**2 129.6**	**1 867.2**	**179.2**	**163.2**	**237.5**	**159.3**	**713.9**	**619.1**	**7.5**	**5.4**	**2 672.8**	**2 298.3**
Proved Developed Non-Producing												
Mining	—	—	—	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—	—	—	—
North America Onshore	—	—	—	—	0.1	0.1	62.3	49.1	0.2	0.1	10.7	8.4
Total Canada	—	—	—	—	0.1	0.1	62.3	49.1	0.2	0.1	10.7	8.4
North Sea	—	—	—	—	13.7	13.7	0.7	0.7	0.1	0.1	13.9	13.9
Other International	—	—	—	—	43.1	14.6	—	—	—	—	43.1	14.6
Total Proved Developed Non-Producing	**—**	**—**	**—**	**—**	**56.9**	**28.4**	**63.0**	**49.8**	**0.3**	**0.2**	**67.7**	**36.9**
Proved Undeveloped												
Mining	—	—	—	—	—	—	—	—	—	—	—	—
In Situ	493.4	430.9	784.5	673.4	—	—	—	—	—	—	1 277.9	1 104.3
East Coast Canada	—	—	—	—	31.9	22.6	—	—	—	—	31.9	22.6
North America Onshore	—	—	—	—	0.1	0.1	80.3	73.9	—	—	13.6	12.4
Total Canada	493.4	430.9	784.5	673.4	32.0	22.7	80.3	73.9	—	—	1 323.4	1 139.3
North Sea	—	—	—	—	31.6	31.6	1.9	1.9	0.1	0.1	31.9	31.9
Other International	—	—	—	—	3.5	1.1	—	—	—	—	3.5	1.1
Total Proved Undeveloped	**493.4**	**430.9**	**784.5**	**673.4**	**67.1**	**55.4**	**82.2**	**75.8**	**0.1**	**0.1**	**1 358.8**	**1 172.3**
Proved												
Mining	1 958.1	1 704.2	—	—	—	—	—	—	—	—	1 958.1	1 704.2
In Situ	664.9	593.9	963.7	836.6	—	—	—	—	—	—	1 628.6	1 430.5
East Coast Canada	—	—	—	—	76.0	55.9	—	—	—	—	76.0	55.9
North America Onshore	—	—	—	—	11.3	9.9	854.1	739.7	7.5	5.3	161.3	138.5
Total Canada	2 623.0	2 298.1	963.7	836.6	87.3	65.8	854.1	739.7	7.5	5.3	3 824.0	3 329.1
North Sea	—	—	—	—	123.6	123.6	5.0	5.0	0.4	0.4	124.7	124.7
Other International	—	—	—	—	150.6	53.7	—	—	—	—	150.6	53.7
Total Proved	**2 623.0**	**2 298.1**	**963.7**	**836.6**	**361.5**	**243.1**	**859.1**	**744.7**	**7.9**	**5.7**	**4 099.3**	**3 507.5**
Probable												
Mining	539.2	462.9	—	—	—	—	—	—	—	—	539.2	462.9
In Situ	1 060.0	878.9	695.1	551.8	—	—	—	—	—	—	1 755.1	1 430.7
East Coast Canada	—	—	—	—	268.5	198.5	—	—	—	—	268.5	198.5
North America Onshore	—	—	—	—	3.5	2.9	264.6	218.4	2.7	2.1	50.4	41.3
Total Canada	1 599.2	1 341.8	695.1	551.8	272.0	201.4	264.6	218.4	2.7	2.1	2 613.2	2 133.4
North Sea	—	—	—	—	43.1	43.1	3.8	3.8	0.2	0.2	43.9	43.9
Other International	—	—	—	—	117.2	45.1	—	—	—	—	117.2	45.1
Total Probable	**1 599.2**	**1 341.8**	**695.1**	**551.8**	**432.3**	**289.6**	**268.4**	**222.2**	**2.9**	**2.3**	**2 774.3**	**2 222.4**
Proved Plus Probable												
Mining	2 497.3	2 167.1	—	—	—	—	—	—	—	—	2 497.3	2 167.1
In Situ	1 724.9	1 472.8	1 658.8	1 388.4	—	—	—	—	—	—	3 383.7	2 861.2
East Coast Canada	—	—	—	—	344.5	254.4	—	—	—	—	344.5	254.4
North America Onshore	—	—	—	—	14.8	12.8	1 118.7	958.1	10.2	7.3	211.7	179.8
Total Canada	4 222.2	3 639.9	1 658.8	1 388.4	359.3	267.2	1 118.7	958.1	10.2	7.3	6 437.2	5 462.5
North Sea	—	—	—	—	166.7	166.7	8.8	8.8	0.6	0.6	168.6	168.6
Other International	—	—	—	—	267.8	98.8	—	—	—	—	267.8	98.8
Total Proved Plus Probable	**4 222.2**	**3 639.9**	**1 658.8**	**1 388.4**	**793.8**	**532.7**	**1 127.5**	**966.9**	**10.8**	**7.9**	**6 873.6**	**5 729.9**

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, 2012
(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	1 958.1	1 709.0	—	—	—	—	—	—	—	—	1 958.1	1 709.0
In Situ	171.5	164.2	179.2	163.8	—	—	—	—	—	—	350.7	328.0
East Coast Canada	—	—	—	—	44.1	32.5	—	—	—	—	44.1	32.5
North America Onshore	—	—	—	—	11.0	10.1	567.0	511.6	6.7	4.8	112.3	100.2
Total Canada	2 129.6	1 873.2	179.2	163.8	55.1	42.6	567.0	511.6	6.7	4.8	2 465.2	2 169.7
North Sea	—	—	—	—	79.4	79.4	2.4	2.4	0.2	0.2	80.0	80.0
Other International	—	—	—	—	104.8	39.0	—	—	—	—	104.8	39.0
Total Proved Developed Producing	**2 129.6**	**1 873.2**	**179.2**	**163.8**	**239.3**	**161.0**	**569.4**	**514.0**	**6.9**	**5.0**	**2 650.0**	**2 288.7**
Proved Developed Non-Producing												
Mining	—	—	—	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—	—	—	—
North America Onshore	—	—	—	—	0.1	0.1	28.0	24.7	0.2	0.1	5.0	4.4
Total Canada	—	—	—	—	0.1	0.1	28.0	24.7	0.2	0.1	5.0	4.4
North Sea	—	—	—	—	14.2	14.2	0.7	0.7	0.1	0.1	14.4	14.4
Other International	—	—	—	—	43.8	15.3	—	—	—	—	43.8	15.3
Total Proved Developed Non-Producing	**—**	**—**	**—**	**—**	**58.1**	**29.6**	**28.7**	**25.4**	**0.3**	**0.2**	**63.2**	**34.1**
Proved Undeveloped												
Mining	—	—	—	—	—	—	—	—	—	—	—	—
In Situ	493.4	459.6	784.5	720.7	—	—	—	—	—	—	1 277.9	1 180.3
East Coast Canada	—	—	—	—	31.9	21.7	—	—	—	—	31.9	21.7
North America Onshore	—	—	—	—	0.1	0.1	5.5	4.9	0.1	0.1	1.0	0.9
Total Canada	493.4	459.6	784.5	720.7	32.0	21.8	5.5	4.9	0.1	0.1	1 310.8	1 202.9
North Sea	—	—	—	—	32.3	32.3	1.9	1.9	—	—	32.6	32.6
Other International	—	—	—	—	3.4	1.2	—	—	—	—	3.4	1.2
Total Proved Undeveloped	**493.4**	**459.6**	**784.5**	**720.7**	**67.7**	**55.3**	**7.4**	**6.8**	**0.1**	**0.1**	**1 346.8**	**1 236.7**
Proved												
Mining	1 958.1	1 709.0	—	—	—	—	—	—	—	—	1 958.1	1 709.0
In Situ	664.9	623.8	963.7	884.5	—	—	—	—	—	—	1 628.6	1 508.3
East Coast Canada	—	—	—	—	76.0	54.2	—	—	—	—	76.0	54.2
North America Onshore	—	—	—	—	11.2	10.3	600.4	541.2	6.9	4.9	118.3	105.4
Total Canada	2 623.0	2 332.8	963.7	884.5	87.2	64.5	600.4	541.2	6.9	4.9	3 781.0	3 376.9
North Sea	—	—	—	—	125.9	125.9	5.2	5.2	0.3	0.3	127.0	127.0
Other International	—	—	—	—	152.0	55.5	—	—	—	—	152.0	55.5
Total Proved	**2 623.0**	**2 332.8**	**963.7**	**884.5**	**365.1**	**245.9**	**605.6**	**546.4**	**7.2**	**5.2**	**4 060.0**	**3 559.4**
Probable												
Mining	539.2	472.2	—	—	—	—	—	—	—	—	539.2	472.2
In Situ	1 060.0	925.6	695.1	591.4	—	—	—	—	—	—	1 755.1	1 517.0
East Coast Canada	—	—	—	—	268.5	191.9	—	—	—	—	268.5	191.9
North America Onshore	—	—	—	—	4.3	4.0	173.3	155.1	2.6	1.9	35.9	31.9
Total Canada	1 599.2	1 397.8	695.1	591.4	272.8	195.9	173.3	155.1	2.6	1.9	2 598.7	2 213.0
North Sea	—	—	—	—	41.6	41.6	3.8	3.8	0.2	0.2	42.4	42.4
Other International	—	—	—	—	116.0	39.5	—	—	—	—	116.0	39.5
Total Probable	**1 599.2**	**1 397.8**	**695.1**	**591.4**	**430.4**	**277.0**	**177.1**	**158.9**	**2.8**	**2.1**	**2 757.1**	**2 294.9**
Proved Plus Probable												
Mining	2 497.3	2 181.2	—	—	—	—	—	—	—	—	2 497.3	2 181.2
In Situ	1 724.9	1 549.4	1 658.8	1 475.9	—	—	—	—	—	—	3 383.7	3 025.3
East Coast Canada	—	—	—	—	344.5	246.1	—	—	—	—	344.5	246.1
North America Onshore	—	—	—	—	15.5	14.3	773.7	696.3	9.5	6.8	154.2	137.3
Total Canada	4 222.2	3 730.6	1 658.8	1 475.9	360.0	260.4	773.7	696.3	9.5	6.8	6 379.7	5 589.9
North Sea	—	—	—	—	167.5	167.5	9.0	9.0	0.5	0.5	169.4	169.4
Other International	—	—	—	—	268.0	95.0	—	—	—	—	268.0	95.0
Total Proved Plus Probable	**4 222.2**	**3 730.6**	**1 658.8**	**1 475.9**	**795.5**	**522.9**	**782.7**	**705.3**	**10.0**	**7.3**	**6 817.1**	**5 854.3**

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, 2012
(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, 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**
Extensions & Improved Recovery [4]									
Mining	—	—	—	—	—	—	—	—	—
In Situ	95.3	(75.2)	20.1	111.2	(98.5)	12.7	—	—	—
East Coast Canada	—	—	—	—	—	—	—	2.8	2.8
North America Onshore	—	—	—	—	—	—	0.7	0.8	1.5
Total Canada	95.3	(75.2)	20.1	111.2	(98.5)	12.7	0.7	3.6	4.3
North Sea	—	—	—	—	—	—	—	—	—
Other International	—	—	—	—	—	—	3.5	7.6	11.1
Total	**95.3**	**(75.2)**	**20.1**	**111.2**	**(98.5)**	**12.7**	**4.2**	**11.2**	**15.4**
Technical Revisions [5]									
Mining	25.2	(13.5)	11.7	—	—	—	—	—	—
In Situ	(110.9)	(136.7)	(247.6)	161.9	99.7	261.6	—	—	—
East Coast Canada	—	—	—	—	—	—	18.3	(9.6)	8.7
North America Onshore	—	—	—	—	—	—	0.1	(2.3)	(2.2)
Total Canada	(85.7)	(150.2)	(235.9)	161.9	99.7	261.6	18.4	(11.9)	6.5
North Sea	—	—	—	—	—	—	4.4	5.4	9.8
Other International	—	—	—	—	—	—	23.8	4.6	28.4
Total	**(85.7)**	**(150.2)**	**(235.9)**	**161.9**	**99.7**	**261.6**	**46.6**	**(1.9)**	**44.7**
Discoveries [6]									
Mining	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—
North America Onshore	—	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	—	—
North Sea	—	—	—	—	—	—	—	1.7	1.7
Other International	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**1.7**	**1.7**

Please see Notes (1) through (7) 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, 2012
(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	—	—	—	—	—	—	—	—	—
Other International	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Economic Factors[7]									
Mining	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—
North America Onshore	—	—	—	—	—	—	(0.1)	—	(0.1)
Total Canada	—	—	—	—	—	—	(0.1)	—	(0.1)
North Sea	—	—	—	—	—	—	—	—	—
Other International	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**(0.1)**	**—**	**(0.1)**
Production									
Mining	(89.6)	—	(89.6)	—	—	—	—	—	—
In Situ	(24.4)	—	(24.4)	(18.2)	—	(18.2)	—	—	—
East Coast Canada	—	—	—	—	—	—	(17.0)	—	(17.0)
North America Onshore	—	—	—	—	—	—	(0.9)	—	(0.9)
Total Canada	(114.0)	—	(114.0)	(18.2)	—	(18.2)	(17.9)	—	(17.9)
North Sea	—	—	—	—	—	—	(17.0)	—	(17.0)
Other International	—	—	—	—	—	—	(15.3)	—	(15.3)
Total	**(114.0)**	**—**	**(114.0)**	**(18.2)**	**—**	**(18.2)**	**(50.2)**	**—**	**(50.2)**
December 31, 2012									
Mining	1 958.1	539.2	2 497.3	—	—	—	—	—	—
In Situ	664.9	1 060.0	1 724.9	963.7	695.1	1 658.8	—	—	—
East Coast Canada	—	—	—	—	—	—	76.0	268.5	344.5
North America Onshore	—	—	—	—	—	—	11.3	3.5	14.8
Total Canada	2 623.0	1 599.2	4 222.2	963.7	695.1	1 658.8	87.3	272.0	359.3
North Sea	—	—	—	—	—	—	123.6	43.1	166.7
Other International	—	—	—	—	—	—	150.6	117.2	267.8
Total	**2 623.0**	**1 599.2**	**4 222.2**	**963.7**	**695.1**	**1 658.8**	**361.5**	**432.3**	**793.8**

Please see Notes (1) through (7) 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, 2012
(forecast prices and costs)

	Natural Gas[8]			NGLs		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	bcf	bcf	bcf	mmbbls	mmbbls	mmbbls
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**
Extensions & Improved Recovery[4]						
Canada – North America Onshore	6.8	3.6	10.4	0.2	—	0.2
North Sea	—	—	—	—	—	—
Other International	—	—	—	—	—	—
Total	**6.8**	**3.6**	**10.4**	**0.2**	**—**	**0.2**
Technical Revisions[5]						
Canada – North America Onshore	61.0	(7.2)	53.8	2.0	(0.2)	1.8
North Sea	0.1	0.7	0.8	0.1	0.1	0.2
Other International	(334.5)	(405.5)	(740.0)	(11.9)	(14.5)	(26.4)
Total	**(273.4)**	**(412.0)**	**(685.4)**	**(9.8)**	**(14.6)**	**(24.4)**
Discoveries[6]						
Canada – North America Onshore	—	—	—	—	—	—
North Sea	—	0.2	0.2	—	—	—
Other International	—	—	—	—	—	—
Total	**—**	**0.2**	**0.2**	**—**	**—**	**—**
Acquisitions						
Canada – North America Onshore	—	—	—	—	—	—
North Sea	—	—	—	—	—	—
Other International	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**
Dispositions						
Canada – North America Onshore	(0.3)	(0.1)	(0.4)	—	—	—
North Sea	—	—	—	—	—	—
Other International	—	—	—	—	—	—
Total	**(0.3)**	**(0.1)**	**(0.4)**	**—**	**—**	**—**
Economic Factors[7]						
Canada – North America Onshore	(35.4)	(52.1)	(87.5)	(0.2)	—	(0.2)
North Sea	—	—	—	—	—	—
Other International	—	—	—	—	—	—
Total	**(35.4)**	**(52.1)**	**(87.5)**	**(0.2)**	**—**	**(0.2)**
Production						
Canada – North America Onshore	(102.9)	—	(102.9)	(1.1)	—	(1.1)
North Sea	(2.2)	—	(2.2)	(0.2)	—	(0.2)
Other International	—	—	—	—	—	—
Total	**(105.1)**	**—**	**(105.1)**	**(1.3)**	**—**	**(1.3)**
December 31, 2012						
Canada – North America Onshore	854.1	264.6	1 118.7	7.5	2.7	10.2
North Sea	5.0	3.8	8.8	0.4	0.2	0.6
Other International	—	—	—	—	—	—
Total	**859.1**	**268.4**	**1 127.5**	**7.9**	**2.9**	**10.8**

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, 2012

(1) The reserves data is based upon evaluations by the Evaluators with an effective date of December 31, 2012.

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

(3) In these tables, Other International includes quantities of crude oil in Libya, which are expected to be produced under EPSAs, which involve the company in upstream risks and rewards, but which do not transfer title of the product to the company. Under these EPSAs, 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. Negative volumes for probable reserves result from the initial recognition of proved reserves for reserves previously assigned as probable reserves.

(5) Technical Revisions include changes in previous estimates, upward or downward, resulting from new technical data or revised interpretations. Technical revisions in 2012 include reserves related to Syria that were reclassified to contingent resources.

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

(7) Economic Factors are changes due primarily to price forecasts, inflation rates or regulatory changes.

(8) Includes associated and non-associated gas (combined).

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 (operated and non-operated) 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 (operated and non-operated) 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 SCO 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 analyses 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 provides 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, 2012
(forecast prices and costs)

	(in $ millions, discounted at % per year)					Unit Value (1)
	0%	5%	10%	15%	20%	$/boe
Proved Developed Producing						
Mining	42 074	26 120	18 046	13 527	10 764	10.59
In Situ	9 102	7 633	6 524	5 668	4 992	20.00
East Coast Canada	1 677	1 565	1 456	1 360	1 278	43.77
North America Onshore	2 530	1 798	1 407	1 163	996	11.96
Total Canada	55 383	37 116	27 433	21 718	18 030	12.58
North Sea	6 121	5 139	4 469	3 987	3 624	56.64
Other International	3 283	2 400	1 888	1 560	1 333	49.65
Total Proved Developed Producing	64 787	44 655	33 790	27 265	22 987	14.70
Proved Developed Non-Producing						
Mining	—	—	—	—	—	—
In Situ	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—
North America Onshore	117	80	59	45	35	6.98
Total Canada	117	80	59	45	35	6.98
North Sea	974	729	578	477	405	41.73
Other International	1 121	863	696	580	497	47.84
Total Proved Developed Non-Producing	2 212	1 672	1 333	1 102	937	36.17
Proved Undeveloped						
Mining	—	—	—	—	—	—
In Situ	24 285	10 339	4 553	1 911	604	4.12
East Coast Canada	1 267	977	792	666	573	35.13
North America Onshore	134	67	30	10	(2)	2.44
Total Canada	25 686	11 383	5 375	2 587	1 175	4.72
North Sea	1 867	1 384	1 043	793	606	32.64
Other International	89	56	36	22	13	30.21
Total Proved Undeveloped	27 642	12 823	6 454	3 402	1 794	5.50
Proved						
Mining	42 074	26 120	18 046	13 527	10 764	10.59
In Situ	33 387	17 972	11 077	7 579	5 596	7.74
East Coast Canada	2 944	2 542	2 248	2 026	1 851	40.28
North America Onshore	2 781	1 945	1 496	1 218	1 029	10.80
Total Canada	81 186	48 579	32 867	24 350	19 240	9.87
North Sea	8 962	7 252	6 090	5 257	4 635	48.84
Other International	4 493	3 319	2 620	2 162	1 843	48.73
Total Proved	94 641	59 150	41 577	31 769	25 718	11.85
Probable						
Mining	22 125	8 109	4 062	2 528	1 813	8.77
In Situ	56 286	14 825	4 956	1 955	826	3.46
East Coast Canada	14 058	8 454	5 567	3 905	2 868	28.05
North America Onshore	1 037	507	299	197	139	7.20
Total Canada	93 506	31 895	14 884	8 585	5 646	6.98
North Sea	3 864	2 769	2 103	1 667	1 364	47.83
Other International	4 880	2 621	1 576	1 037	732	34.97
Total Probable	102 250	37 285	18 563	11 289	7 742	8.35
Proved Plus Probable						
Mining	64 199	34 229	22 108	16 055	12 577	10.20
In Situ	89 673	32 797	16 033	9 534	6 422	5.60
East Coast Canada	17 002	10 996	7 815	5 931	4 719	30.73
North America Onshore	3 818	2 452	1 795	1 415	1 168	9.97
Total Canada	174 692	80 474	47 751	32 935	24 886	8.74
North Sea	12 826	10 021	8 193	6 924	5 999	48.58
Other International	9 373	5 940	4 196	3 199	2 575	42.46
Total Proved Plus Probable	196 891	96 435	60 140	43 058	33 460	10.50

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

Net Present Value of Future Net Revenues After Income Taxes

as at December 31, 2012
(forecast prices and costs)

	(in $ millions, discounted at % per year)				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	32 101	19 682	13 491	10 068	7 993
In Situ	7 634	6 403	5 477	4 764	4 203
East Coast Canada	1 437	1 339	1 242	1 157	1 083
North America Onshore	2 069	1 480	1 163	965	829
Total Canada	43 241	28 904	21 373	16 954	14 108
North Sea	1 938	1 655	1 451	1 304	1 192
Other International	1 150	853	681	570	494
Total Proved Developed Producing	46 329	31 412	23 505	18 828	15 794
Proved Developed Non-Producing					
Mining	—	—	—	—	—
In Situ	—	—	—	—	—
East Coast Canada	—	—	—	—	—
North America Onshore	86	57	41	31	23
Total Canada	86	57	41	31	23
North Sea	373	284	230	193	167
Other International	393	307	251	212	184
Total Proved Developed Non-Producing	852	648	522	436	374
Proved Undeveloped					
Mining	—	—	—	—	—
In Situ	17 830	7 178	2 854	926	(2)
East Coast Canada	984	745	594	491	416
North America Onshore	98	43	14	(1)	(10)
Total Canada	18 912	7 966	3 462	1 416	404
North Sea	715	543	418	323	251
Other International	31	20	13	8	5
Total Proved Undeveloped	19 658	8 529	3 893	1 747	660
Proved					
Mining	32 101	19 682	13 491	10 068	7 993
In Situ	25 464	13 581	8 331	5 690	4 201
East Coast Canada	2 421	2 084	1 836	1 648	1 499
North America Onshore	2 253	1 580	1 218	995	842
Total Canada	62 239	36 927	24 876	18 401	14 535
North Sea	3 026	2 482	2 099	1 820	1 610
Other International	1 574	1 180	945	790	683
Total Proved	66 839	40 589	27 920	21 011	16 828
Probable					
Mining	17 338	6 155	2 987	1 819	1 288
In Situ	41 597	10 577	3 337	1 165	359
East Coast Canada	10 447	6 224	4 041	2 785	2 003
North America Onshore	772	375	218	142	98
Total Canada	70 154	23 331	10 583	5 911	3 748
North Sea	1 493	1 097	852	689	575
Other International	1 708	930	567	378	270
Total Probable	73 355	25 358	12 002	6 978	4 593
Proved Plus Probable					
Mining	49 439	25 837	16 478	11 887	9 281
In Situ	67 061	24 158	11 668	6 855	4 560
East Coast Canada	12 868	8 308	5 877	4 433	3 502
North America Onshore	3 025	1 955	1 436	1 137	940
Total Canada	132 393	60 258	35 459	24 312	18 283
North Sea	4 519	3 579	2 951	2 509	2 185
Other International	3 282	2 110	1 512	1 168	953
Total Proved Plus Probable	140 194	65 947	39 922	27 989	21 421

Total Future Net Revenues
as at December 31, 2012
(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	207 480	27 467	100 870	37 069	—	42 074	9 973	32 101
In Situ	27 078	1 762	12 833	3 263	118	9 102	1 468	7 634
East Coast Canada	4 492	1 102	1 205	203	305	1 677	240	1 437
North America Onshore	5 743	734	2 336	11	132	2 530	461	2 069
Total Canada	244 793	31 065	117 244	40 546	555	55 383	12 142	43 241
North Sea	8 175	—	1 885	56	113	6 121	4 183	1 938
Other International	4 103	—	502	294	24	3 283	2 133	1 150
Total Proved Developed Producing	257 071	31 065	119 631	40 896	692	64 787	18 458	46 329
Proved Developed Non-Producing								
Mining	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—
North America Onshore	353	50	159	24	3	117	31	86
Total Canada	353	50	159	24	3	117	31	86
North Sea	1 477	—	492	—	11	974	601	373
Other International	1 529	—	216	183	9	1 121	728	393
Total Proved Developed Non-Producing	3 359	50	867	207	23	2 212	1 360	852
Proved Undeveloped								
Mining	—	—	—	—	—	—		—
In Situ	121 065	17 066	49 267	29 793	654	24 285	6 455	17 830
East Coast Canada	3 331	973	659	396	36	1 267	283	984
North America Onshore	457	26	110	172	15	134	36	98
Total Canada	124 853	18 065	50 036	30 361	705	25 686	6 774	18 912
North Sea	3 260	—	706	643	44	1 867	1 152	715
Other International	124	—	7	28	—	89	58	31
Total Proved Undeveloped	128 237	18 065	50 749	31 032	749	27 642	7 984	19 658
Proved								
Mining	207 480	27 467	100 870	37 069	—	42 074	9 973	32 101
In Situ	148 143	18 828	62 100	33 056	772	33 387	7 923	25 464
East Coast Canada	7 823	2 075	1 864	599	341	2 944	523	2 421
North America Onshore	6 553	810	2 605	207	150	2 781	528	2 253
Total Canada	369 999	49 180	167 439	70 931	1 263	81 186	18 947	62 239
North Sea	12 912	—	3 083	699	168	8 962	5 936	3 026
Other International	5 756	—	725	505	33	4 493	2 919	1 574
Total Proved	388 667	49 180	171 247	72 135	1 464	94 641	27 802	66 839
Probable								
Mining	74 945	10 839	31 498	10 483	—	22 125	4 787	17 338
In Situ	231 787	43 348	86 463	44 926	764	56 286	14 689	41 597
East Coast Canada	27 946	7 362	3 790	2 532	204	14 058	3 611	10 447
North America Onshore	2 570	374	1 067	76	16	1 037	265	772
Total Canada	337 248	61 923	122 818	58 017	984	93 506	23 352	70 154
North Sea	4 634	—	626	121	23	3 864	2 371	1 493
Other International	5 272	—	326	63	3	4 880	3 172	1 708
Total Probable	347 154	61 923	123 770	58 201	1 010	102 250	28 895	73 355
Proved Plus Probable								
Mining	282 425	38 306	132 368	47 552	—	64 199	14 760	49 439
In Situ	379 930	62 176	148 563	77 982	1 536	89 673	22 612	67 061
East Coast Canada	35 769	9 437	5 654	3 131	545	17 002	4 134	12 868
North America Onshore	9 123	1 184	3 672	283	166	3 818	793	3 025
Total Canada	707 247	111 103	290 257	128 948	2 247	174 692	42 299	132 393
North Sea	17 546	—	3 709	820	191	12 826	8 307	4 519
Other International	11 028	—	1 051	568	36	9 373	6 091	3 282
Total Proved Plus Probable	735 821	111 103	295 017	130 336	2 474	196 891	56 697	140 194

Future Net Revenues by Production Group
as at December 31, 2012
(forecast prices and costs)

(before income taxes, discounted at 10% per year)	$ millions	$/boe [1]
Proved Developed Producing		
Unconventional – Mining	18 046	10.59
Unconventional – In Situ	6 524	20.00
Total Unconventional [2]	24 570	12.10
Light & Medium Oil [3]	8 138	50.03
Natural Gas [4]	1 082	10.29
Total Proved Developed Producing	33 790	14.70
Proved		
Unconventional – Mining	18 046	10.59
Unconventional – In Situ	11 077	7.74
Total Unconventional [2]	29 123	9.29
Light & Medium Oil [3]	11 290	45.80
Natural Gas [4]	1 164	9.21
Total Proved	41 577	11.85
Proved Plus Probable		
Unconventional – Mining	22 108	10.20
Unconventional – In Situ	16 033	5.60
Total Unconventional [2]	38 141	7.59
Light & Medium Oil [3]	20 610	38.36
Natural Gas [4]	1 389	8.43
Total Proved Plus Probable	60 140	10.50

(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

In Situ Future Net Revenues

Future net revenues for In Situ properties include the production of both upgraded SCO and non-upgraded bitumen, and, as such, include a portion of the company's estimated upgrading development and operating costs.

Prices Realized

For prices realized by Suncor during 2012, 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, 2013, 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 1.00, a Cdn$/€ exchange rate of 1.30 and a Cdn$/£ exchange rate of 1.60. Forecast costs included a 2% inflation factor, except for costs for Mining, which included 4% inflation for 2014 to 2016, 3% inflation for 2017 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 2012.

Constant prices included a US$/Cdn$ exchange rate of 1.00, a Cdn$/€ exchange rate of 1.29 and a Cdn$/£ exchange rate of 1.59.

Prices used in Reserves Tables(1)

Forecast	Brent (2)	WTI (3)	WCS (4)	Light Sweet (5)	Pentanes (6)	AECO (7)	B.C. Gas (8)	NBP (9)
Year	US$/bbl	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/mmbtu	Cdn$/mmbtu
2013	105.00	90.00	70.13	85.00	96.63	3.38	3.18	9.13
2014	102.50	92.50	76.15	91.50	97.91	3.83	3.63	9.32
2015	102.50	95.00	78.22	94.00	97.76	4.28	4.08	9.76
2016	102.50	97.50	80.29	96.50	100.36	4.72	4.52	10.25
2017	100.00	97.50	80.29	96.50	100.36	4.95	4.75	10.00
2018	100.00	97.50	80.29	96.50	100.36	5.22	5.02	10.00
2019	101.35	98.54	81.16	97.54	101.44	5.32	5.12	10.14
2020	103.38	100.51	82.79	99.51	103.49	5.43	5.23	10.34
2021	105.45	102.52	84.46	101.52	105.58	5.54	5.34	10.55
2022	107.55	104.57	86.16	103.57	107.71	5.64	5.44	10.76
2023+	+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$/bbl	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/mmbtu	Cdn$/mmbtu
All years	111.96	94.71	72.83	87.50	102.42	2.33	2.26	9.35

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

(2) 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.

(3) NYMEX WTI crude oil at Cushing, Oklahoma.

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

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

(6) 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.

(7) 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.

(8) 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.

(9) National Balancing Point (U.K.). Price used when determining natural gas reserves presented as North Sea 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 EPSAs. 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 2012 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, 2012
(forecast prices and costs)

($ millions)	2013	2014	2015	2016	2017	Remainder	Total	Discounted At 10%
Proved								
Mining	1 775	1 851	1 693	1 703	1 615	28 432	37 069	16 393
In Situ	1 533	1 130	1 142	1 165	1 193	26 893	33 056	12 565
East Coast Canada	286	105	25	44	25	114	599	483
North America Onshore	19	15	78	23	23	49	207	150
Total Canada	3 613	3 101	2 938	2 935	2 856	55 488	70 931	29 591
North Sea	326	247	86	40	—	—	699	651
Other International	78	49	51	64	35	228	505	316
Total Proved	4 017	3 397	3 075	3 039	2 891	55 716	72 135	30 558
Proved Plus Probable								
Mining	1 851	1 928	1 771	1 793	1 718	38 491	47 552	18 436
In Situ	1 231	1 562	2 260	2 975	2 251	67 703	77 982	18 638
East Coast Canada	694	667	572	348	229	621	3 131	2 370
North America Onshore	31	30	127	23	23	49	283	216
Total Canada	3 807	4 187	4 730	5 139	4 221	106 864	128 948	39 660
North Sea	413	259	108	40	—	—	820	768
Other International	77	55	51	64	35	286	568	330
Total Proved Plus Probable	4 297	4 501	4 889	5 243	4 256	107 150	130 336	40 758

Development costs include costs associated with both developed and undeveloped reserves. Significant development activities for 2013 are expected to include:

- For Mining, tailings management facilities for Oil Sands Base and Syncrude, and costs for mine train relocations and mine train replacements at Syncrude. Remaining development costs relate to capital investments that maintain the production capacity of existing facilities, including, but not limited to, major maintenance, truck and shovel replacement, the replenishment of catalysts in hydrotreating units at the upgraders and improvements to utilities, roads and other facilities.
- For both Firebag and MacKay River operations within In Situ, the drilling of new well pairs and infill wells, and the design and construction of new well pads that are expected to maintain existing production levels in future years.
- For East Coast Canada, construction activities at Hebron, development drilling at Terra Nova, White Rose and Hibernia, procurement and installation of subsea infrastructure for the HSEU and White Rose Extensions, and continuation of H_2S remediation activities at Terra Nova.
- For North Sea, at Buzzard, development drilling and facility upgrades, and at Golden Eagle, the commencement of development drilling and the continuing construction of facilities, including the installation of a wellhead deck.
- For North America Onshore, costs for the development of the Wilson Creek field in the Cardium oil formation.
- For Other International, costs for development drilling, and upgrades and maintenance to facilities in Libya.

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 its overall operations. The specific estimates established for forecasted abandonment and reclamation costs are determined in accordance with Canadian GAAP and presented in Suncor's 2012 audited Consolidated Financial Statements, and are based on available information, consistent with that assumed in our long-range planning. This review considers the nature of Suncor's forecasted production and development plans and estimated abandonment and reclamation costs, where determinable, for liabilities associated with its upstream operations as at December 31, 2012. 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, 2012, 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 $8.2 billion (discounted at 10%, approximately $2.3 billion). Suncor estimates that it will incur $1.143 billion of its identified abandonment and reclamation costs during the next three years (undiscounted: 2013 – $388 million, 2014 – $374 million, 2015 – $381 million), over 85% of which is associated with Oil Sands mining operations. This cost estimate does not include the company's estimated abandonment and reclamation costs for its Refining and Marketing assets ($171 million, undiscounted and uninflated).

Approximately $2.5 billion (undiscounted) has been deducted as abandonment costs in estimating the future net revenues from proved plus probable reserves. This $2.5 billion represents the abandonment obligation for approximately 6,000 net production wells and approximately 2,000 net service and other wells, including a forecasted number of future wells for undeveloped reserves related to in situ and conventional activities that are not included in Suncor's $8.2 billion total.

Abandonment and reclamation costs included in Suncor's $8.2 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		2010		2011		2012	
	First Attributed	Total at December 31 2009	First Attributed	Total at December 31 2010	First Attributed	Total at December 31 2011	First Attributed	Total at December 31 2012
SCO (mmbbls)								
Mining	—	—	—	—	—	—	—	—
In Situ	564.0	564.0	14.0	651.0	—	502.0	45.9	493.4
Total SCO	564.0	564.0	14.0	651.0	—	502.0	45.9	493.4
Bitumen (mmbbls)								
Mining	—	—	—	—	—	—	—	—
In Situ	427.0	427.0	2.0	360.0	315.0	661.0	63.7	784.5
Total Bitumen	427.0	427.0	2.0	360.0	315.0	661.0	63.7	784.5
Light & Medium Oil (mmbbls)								
East Coast Canada	35.0	35.0	3.0	28.0	1.4	26.6	3.9	31.9
North America Onshore	0.3	0.3	—	0.2	0.1	0.3	—	0.1
Total Canada	35.3	35.3	3.0	28.2	1.5	26.9	3.9	32.0
North Sea[(3)]	68.0	68.0	—	19.0	24.6	43.3	—	31.6
United States[(4)]	8.3	8.3	—	—	—	—	—	—
Other International[(5)]	—	—	6.0	6.0	1.8	5.8	3.5	3.5
Total Light & Medium Oil	111.6	111.6	9.0	53.2	27.9	76.0	7.4	67.1
Natural Gas (bcf)								
North America Onshore – Canada	15.6	15.6	32.0	118.4	2.1	78.7	—	80.3
North Sea[(3)]	—	—	—	1.0	1.5	2.7	—	1.9
United States[(4)]	23.9	23.9	—	—	—	—	—	—
Other International[(5)]	413.0	413.0	—	—	—	—	—	—
Total Natural Gas	452.5	452.5	32.0	119.4	3.6	81.4	—	82.2
NGLs (mmbbls)								
North America Onshore – Canada	0.4	0.4	—	0.1	—	0.1	—	—
North Sea[(3)]	1.0	1.0	—	—	—	—	—	—
Other International[(5)]	9.0	9.0	—	—	—	—	—	—
Total NGLs	10.4	10.4	—	0.1	—	0.1	—	—
Total (mmboe)	1 188.4	1 188.4	30.4	1 084.2	343.5	1 252.7	117.0	1 358.8

Gross Probable Undeveloped Reserves
(forecast prices and costs)

	Prior		2010		2011		2012	
	First Attributed	Total at December 31 2009	First Attributed	Total at December 31 2010	First Attributed	Total at December 31 2011	First Attributed	Total at December 31 2012
SCO (mmbbls)								
Mining	264.0	264.0	—	215.0	—	263.0	—	260.0
In Situ	595.0	595.0	6.0	400.0	916.0	1 212.0	—	1 043.4
Total SCO	859.0	859.0	6.0	615.0	916.0	1 475.0	—	1 303.4
Bitumen (mmbbls)								
Mining	—	—	—	37.0	—	—	—	—
In Situ	1 550.0	1 550.0	8.0	1 835.0	38.0	669.0	—	594.3
Total Bitumen	1 550.0	1 550.0	8.0	1 872.0	38.0	669.0	—	594.3
Light & Medium Oil (mmbbls)								
East Coast Canada	80.0	80.0	7.0	85.0	143.2	217.4	4.4	221.7
North America Onshore	5.1	5.1	0.3	3.5	0.7	2.0	0.4	0.4
Total Canada	85.1	85.1	7.3	88.5	143.9	219.4	4.8	222.1
North Sea (3)	35.0	35.0	—	15.0	13.8	17.1	1.7	32.7
United States (4)	3.8	3.8	—	—	—	—	—	—
Other International (5)	62.0	62.0	8.0	11.0	3.8	14.5	7.6	7.6
Total Light & Medium Oil	185.9	185.9	15.3	114.5	161.5	251.0	14.1	262.4
Natural Gas (bcf)								
North America Onshore – Canada	233.2	233.2	75.2	136.2	3.2	86.9	1.1	49.3
North Sea (3)	50.0	50.0	—	1.0	1.2	1.5	0.1	3.0
United States (4)	12.0	12.0	—	—	—	—	—	—
Other International (5)	651.0	651.0	—	240.0	221.4	347.4	—	—
Total Natural Gas	946.2	946.2	75.2	377.2	225.8	435.8	1.2	52.3
NGLs (mmbbls)								
North America Onshore – Canada	1.0	1.0	0.1	1.0	—	0.8	—	0.7
North Sea (3)	1.0	1.0	—	—	—	—	—	0.1
Other International (5)	18.0	18.0	—	8.0	6.0	11.5	—	—
Total NGLs	20.0	20.0	0.1	9.0	6.0	12.3	—	0.8
Total (mmboe)	2 772.6	2 772.6	41.9	2 673.4	1 159.1	2 479.9	14.3	2 169.7

(1) The term First Attributed represents undeveloped reserves additions, including acquisitions, discoveries and extensions pertaining to the year in which the events first occurred.

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

(3) In these tables, "North Sea" includes additional properties previously held by Suncor in the Netherlands portion of the North Sea and subsequently disposed in 2010.

(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, and subsequently disposed in 2010, and for 2011 and prior, Syria.

Undeveloped In Situ reserves, which constitute approximately 94% of Suncor's gross proved undeveloped reserves and 76% of Suncor's gross probable undeveloped reserves, will take several 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 in situ wells. Suncor has delineated In Situ reserves to a high degree of certainty through seismic data and core hole drilling, consistent with COGE Handbook guidelines. In most cases, proved reserves have been drilled to a density of 16 wells per section, which is 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 12% of Suncor's gross probable undeveloped reserves, relate solely to the Syncrude Aurora South mining area, which has regulatory approvals substantially in place and is well-delineated by core hole drilling. The co-owners of Syncrude do not expect that the Aurora South mining area will come on-stream in this decade.

Undeveloped conventional (light and medium oil, natural gas and NGLs) reserves constitute approximately 6% of Suncor's gross proved undeveloped reserves and approximately 12% 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 that are limited by production facility capacity.

Properties with no Attributed Reserves

The following table is a summary of properties to which no reserves are attributed as at December 31, 2012. 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	5 056 676	3 695 849
Libya	2 950 978	1 339 489
U.S. – Alaska	1 143 335	381 074
Norway	379 594	161 512
Syria [(1)]	345 194	345 194
U.K.	129 147	38 303
Australia (overriding royalty interest only)	113 027	—
Total	10 117 951	5 961 421

(1) Does not include hectares for lands associated with reserves that were reclassified to contingent resources in 2012 as a result of the suspension of operations.

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 2013, Suncor's rights to 318,222 net hectares in Canada, 30,500 net hectares in Alaska and 39,693 net hectares in the U.K. portion of the North Sea are scheduled to expire. Substantial portions of expiring lands may have their tenure continued beyond 2013 through the conduct of work programs and/or the payment of prescribed fees to the rights owner. No land tenure expiries are scheduled to occur for either Mining or In Situ properties for 2013.

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 and Libya, 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 operations as at December 31, 2012.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta – In Situ	198	198.0	64	64.0	—	—	—	—
Alberta – Conventional	158	140.7	12	9.5	4 332	2 963.8	93	67.9
British Columbia	5	4.4	7	7.0	235	179.1	131	109.5
Saskatchewan	—	—	—	—	729	263.6	97	47.2
Newfoundland	62	15.5	4	1.5	—	—	—	—
North Sea	24	7.2	8	2.4	—	—	—	—
Other International [(1)]	242	121.0	173	88.1	—	—	6	6.0
Total	689	486.8	268	172.5	5 296	3 406.5	327	230.6

(1) In this table, Other International includes wells associated with the company's suspended operations in Syria, although there are no reserves associated with these wells. The number assumes that no wells have been damaged since Suncor exited the country in December of 2011.

(2) Non-producing wells include, but are not limited to, wells that are not producing where there is no near-term plan for abandonment, wells where drilling has finished, but the well has not been completed, wells requiring maintenance or workover where the resumption of production is not known, and wells that have been shut in and the date of resumption of production is not known with reasonable certainty.

(3) Non-producing wells presented in this table do not necessarily lead to classification of non-producing reserves, which are described subsequently in this description.

(4) Producing wells for In Situ include wells that have commenced steaming.

There are no producing 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. Wells where steam injection has commenced are classified as producing.

The majority of 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. Proved plus probable developed non-producing reserves for conventional assets represent less than 2% of the company's total proved plus probable reserves. These remaining non-producing reserves are primarily associated with:

- Recently drilled wells to be brought on production in 2013;
- Secondary zones forecast to be brought on-stream over the next two years;
- Wells requiring workovers, which are anticipated to be undertaken over the next two years;
- 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 oil and gas activities for the year ended December 31, 2012.

($ millions)	Exploration Costs	Proved Property Acquisition Costs	Unproved Property Acquisition Costs	Development Costs	Other[1] Costs	Total
Canada – Mining and In Situ	185	—	—	3 825	468	4 478
Canada – East Coast Canada and North America Onshore	9	—	—	727	—	736
North Sea	241	—	—	288	—	529
Other International	—	—	—	11	—	11
Total	435	—	—	4 851	468	5 754

(1) Other includes infrastructure for pipelines and storage tanks to support marketing logistics and flexibility.

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, 2012.

Total number of wells completed	Exploratory Wells [1]		Development Wells	
	Gross	Net	Gross	Net
Canada – Oil Sands				
Oil	1	1.0	30	30.0
Service [2]	10	10.0	80	85.0
Stratigraphic Test [3]	220	140.5	478	292.3
Total	231	151.5	588	407.3
Canada – East Coast Canada and North America Onshore				
Oil	—	—	22	17.4
Natural Gas	1	1.0	1	0.2
Dry Hole	—	—	1	1.0
Service	—	—	2	0.4
Total	1	1.0	26	19.0
North Sea				
Oil	1	0.3	4	1.2
Dry Hole	3	0.9	—	—
Stratigraphic Test [3]	3	1.2	—	—
Total	7	2.4	4	1.2
Other International				
Oil	—	—	4	2.0
Total	—	—	4	2.0

(1) Exploratory wells for Oil Sands include activity related to technology pilot projects.

(2) Service wells for Oil Sands include the injection well in a SAGD well pair, in addition to observation and disposal wells.

(3) Stratigraphic test wells for Oil Sands include core hole drilling. Stratigraphic test wells for offshore properties include appraisal wells.

Significant exploration and development wells completed in 2012 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, and core hole drilling at Joslyn to further delineate resources.
- For In Situ, the drilling of new well pairs and infill wells at Firebag and MacKay River that are expected to assist in maintaining production levels in future years, a core hole drilling program at Meadow Creek to further delineate resources, and activity to start up a pilot technology project.
- For East Coast Canada, development drilling for Hibernia, White Rose and the White Rose Extensions.
- For North Sea, exploration drilling for the Cooper prospect and appraisal drilling for the Beta prospect in the Norway sector of the North Sea, development and exploration drilling at Buzzard, and an exploration well for the Griffon prospect in the U.K. sector of the North Sea.
- For Other International, oil development wells in Libya.
- For North America Onshore, development drilling of the Wilson Creek and Ferrier fields in the Cardium oil formation 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.

	2012			
	Three months ended			
	Mar 31	Jun 30	Sept 30	Dec 31
Canada				
Oil Sands (1)				
Average total production (mbbls/d)	341.1	337.8	378.9	378.7
Average In Situ bitumen production (mbbls/d)	114.6	127.8	130.0	151.3
Average price realized ($/bbl)	91.71	79.70	81.72	77.37
Royalties ($/bbl)	(9.01)	(2.51)	(7.53)	(1.87)
Total cash operating costs ($/bbl)	(37.51)	(40.14)	(33.45)	(38.12)
In Situ cash operating costs ($/bbl)	(22.45)	(20.80)	(18.00)	(17.10)
Light & Medium Oil				
Average total production (mbbls/d)	65.3	49.8	22.7	48.3
Average price realized ($/bbl)	122.31	104.25	108.49	108.37
Royalties ($/bbl)	(34.72)	(38.83)	(31.16)	(27.17)
Production costs ($/bbl)	(8.53)	(12.71)	(33.17)	(12.00)
Netback ($/bbl)	79.06	52.71	44.16	69.20
Natural Gas (2)				
Average total production (mmcfe/d)	358	325	312	299
Average price realized ($/mcfe)	3.71	3.14	3.46	4.38
Royalties ($/mcfe)	(0.24)	(0.20)	(0.28)	(0.38)
Production costs ($/mcfe)	(1.48)	(1.56)	(1.63)	(1.39)
Netback ($/mcfe)	1.99	1.38	1.55	2.61
North Sea				
Light & Medium Oil (3)				
Average total production (mboe/d)	57.0	57.9	41.9	35.3
Average price realized ($/boe)	111.83	103.18	104.06	104.19
Royalties ($/boe)	(0.00)	(0.00)	(0.00)	(0.00)
Production costs ($/boe)	(4.80)	(3.36)	(8.24)	(10.71)
Netback ($/boe)	107.03	99.82	95.82	93.48
Other International				
Light & Medium Oil				
Average total production (mboe/d)	39.2	42.7	39.8	44.4
Average price realized ($/boe)	118.47	109.44	107.32	108.05
Royalties ($/boe)	(67.13)	(57.50)	(61.02)	(81.09)
Production costs ($/boe)	(1.86)	(2.76)	(1.13)	(1.97)
Netback ($/boe)	49.48	49.18	45.17	24.99

(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 operation.

(2) Volumes include NGLs and crude oil from North America Onshore operations.

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

The following table provides the production volumes for each of Suncor's important fields for the year ended December 31, 2012.

	SCO	Bitumen	Light & Medium Oil
	mbbls/d	mbbls/d	mbbls/d
Mining – Suncor	211.0	—	—
Mining – Syncrude	34.4	—	—
Firebag	64.2	23.0	—
MacKay River	1.5	25.1	—
Buzzard	—	—	48.0
Hibernia	—	—	26.1
White Rose	—	—	11.6
Terra Nova	—	—	8.8

Production Estimates

The table below outlines the volume of the company's production of gross proved, gross probable and gross proved plus probable reserves estimated for the year ending December 31, 2013, 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 2013 for proved plus probable reserves, evaluated as at December 31, 2012, from: Suncor's mining operations (excluding Syncrude) are 237 mbbls/d of SCO, approximately 37% of total estimated production for 2013; and from Firebag are 132 mbbls/d of SCO and bitumen, approximately 20% of total estimated production for 2013.

	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	mbbls/d	mbbls/d	mmcf/d	mmcf/d	mbbls/d	mbbls/d
Canada										
Proved	325.2	307.9	77.0	69.6	46.9	35.1	252.1	217.3	2.7	1.9
Probable	15.9	14.3	18.0	20.2	18.0	11.3	7.0	6.0	0.2	0.2
Proved Plus Probable	341.1	322.2	95.0	89.8	64.9	46.4	259.1	223.3	2.9	2.1
North Sea										
Proved	—	—	—	—	49.1	49.1	4.9	4.9	0.4	0.4
Probable	—	—	—	—	2.7	2.7	0.5	0.5	—	—
Proved Plus Probable	—	—	—	—	51.8	51.8	5.4	5.4	0.4	0.4
Other International										
Proved	—	—	—	—	45.0	7.9	—	—	—	—
Probable	—	—	—	—	—	—	—	—	—	—
Proved Plus Probable	—	—	—	—	45.0	7.9	—	—	—	—
Total										
Proved	325.2	307.9	77.0	69.6	141.0	92.1	257.0	222.2	3.1	2.3
Probable	15.9	14.3	18.0	20.2	20.7	14.0	7.5	6.5	0.2	0.2
Proved Plus Probable	341.1	322.2	95.0	89.8	161.7	106.1	264.5	228.7	3.3	2.5

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, 2012. These commitments run through 2015 and are primarily for conducting seismic programs and drilling exploration wells.

Country/Area ($ millions)	2013	Total
Canada	—	24
North Sea	21	162
Other International	67	272

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 2012. A description of Suncor's use of such instruments is provided in the 2012 audited Consolidated Financial Statements and related MD&A for the year ended December 31, 2012.

Suncor holds a commitment of 85,000 mcf/d of contract capacity on the Alliance Pipeline system that expires in November 2015, which enables Suncor to transport natural gas from northeastern B.C. and northwestern Alberta to the Alliance Pipeline terminus in Illinois. In addition, Suncor holds a commitment of approximately 65,000 mcf/d of contract capacity on the GTN system that expires in 2023, which delivers natural gas to the Pacific Northwest and California markets. Suncor estimates its minimum commitments on the Alliance Pipelines system and the GTN system to be approximately US$51 million and US$9 million, respectively. These costs were not included in Suncor's reserves evaluations. Due to divestitures of natural gas properties subsequent to the merger with Petro-Canada, ongoing natural declines in reservoir performance and the recent shut-in of certain fields in response to low natural gas prices, Suncor's proprietary production is insufficient to meet the company's internal consumption requirements across all of its businesses and fill its contracted pipeline commitments. Suncor utilizes approximately half of the contract capacity on the Alliance Pipeline system with proprietary production and utilizes no capacity on the GTN with proprietary production. Suncor purchases natural gas from third parties to supplement its proprietary production, and to utilize the GTN and Alliance pipeline capacities on an opportunistic basis when price differentials at the delivery locations exceed, at a minimum, the variable cost of transportation on the respective pipelines.

Tax Horizon

In 2012, 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. Based on projected future net earnings, Suncor is expected to be cash taxable on the majority of its Canadian earnings in 2013.

Contingent Resources

GLJ conducted an independent assessment of Best Estimate contingent resources volumes for all of Suncor's Mining properties and its Firebag and Steepbank In Situ properties. For remaining In Situ properties, including MacKay River, GLJ audited assessments of Best Estimate contingent resources volumes (approximately 48% of In Situ contingent resources) prepared by Suncor's internal qualified reserves evaluators. Sproule Unconventional Limited conducted an independent assessment of Suncor's Best Estimate contingent resources in the Montney shale formation of northeast B.C., with an effective date of June 30, 2012. Best Estimate contingent resources for remaining conventional properties were prepared by Suncor's internal qualified reserves evaluators without independent audit or review. All contingent resources estimates were conducted in accordance with the COGE Handbook. The effective date of Suncor's best estimate of contingent resources is as of December 31, 2012, except in the case of the Montney shale formation of northeast B.C., which is as at June 30, 2012, and in the case of Syria, which is as at December 31, 2011.

In 2011, the company's assets in Syria were impacted by political unrest. As a result, volumes previously reported as reserves based on an evaluation conducted by Sproule with an effective date of December 31, 2011 have been reclassified to contingent resources. In reclassifying the reserves to contingent resources, the company was not able to update any information used by Sproule to conduct its 2011 evaluation, due to the political unrest and international sanctions against Syria. The contingent resources estimate for Syria assumes that there has been no production subsequent to Sproule's evaluation and that infrastructure, including wells and pipelines, existing at December 31, 2011, exist at December 31, 2012. Therefore, these contingent resources are subject to uncertainty arising from any new information or change in circumstances, such as production, changes in asset performance or development activities, about which Suncor and Sproule are unaware.

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 contingent resources are 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, or as to the timing of any such development. The economic viability of the contingent resources is dependent upon pricing and economic conditions. Estimates of contingent resources have not been adjusted for risk based on the chance of development. Significant factors that may change contingent resources estimates include further delineation drilling, future technology improvements, and additional processing capacity.

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

- The need for higher density core hole drilling to improve the certainty of Mining and In Situ resources;

- The need for further facility design and the associated uncertainty in development costs and timelines;
- The preparation of firm development plans and regulatory applications (including associated reservoir studies and delineation drilling);
- Regulatory approvals; and
- Board, management or partner approval, as applicable, to proceed with development.

The additional facility design work, development plans, reservoir studies and delineation drilling are often completed in the course of preparing the company's application for regulatory approvals. Once there is a high level of certainty of receiving all regulatory, corporate and co-owner approvals, as applicable, and all other contingencies are removed, the resources may then be reclassified as reserves.

Also, the company has assumed that some Mining and 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.

Suncor's Best Estimate of gross contingent resources are set out in the table below. Gross contingent resource means Suncor's working interest (operated and non-operated) share before deduction of royalties and without including any royalty interests of Suncor.

Best Estimate Gross Contingent Resources	SCO	Bitumen	Light & Medium Oil	Natural Gas	NGLs	Total
	mmbbls	mmbbls	mmbbls	bcf	mmbbls	mmboe
Mining	4 582	2 112	—	—	—	6 694
In Situ	6 419	5 997	—	—	—	12 416
East Coast Canada	—	—	250	2 679	—	696
North America Onshore (1) (2)	—	—	35	16 026	223	2 929
Total Canada	11 001	8 109	285	18 705	223	22 735
North America Onshore – U.S	—	—	—	449	—	75
North Sea (3)	—	—	76	66	—	87
Other International (4)	—	—	398	985	27	589
As at December 31, 2012	11 001	8 109	759	20 205	250	23 486
As at December 31, 2011	11 014	8 176	889	10 634	14	21 865

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

(2) In this table, North America Onshore includes contingent resources for the Montney shale formation of northeast B.C., with an effective date of June 30, 2012. The contingent resources associated with this formation include 7,358 bcf of Natural Gas and 197 mmbbls of NGLs.

(3) Contingent resources include offshore Norway and the U.K.

(4) In this table, Other International includes contingent resources for Syria, which were previously classified as reserves as at December 31, 2011, based on a reserves evaluation prepared by Sproule with an effective date of December 31, 2011. These reserves have been reclassified as contingent resources as a result of Suncor's suspension of operations in Syria and the resources have an effective date of December 31, 2011.

Contingent resources increased to 23,486 mmboe at December 31, 2012 from 21,865 mmboe at December 31, 2011. Contingent resources increased due primarily to drilling results on Suncor's properties in the Montney formation that added natural gas and NGL contingent resources, and the reclassification of proved plus probable reserves to contingent resources associated with the suspension of operations in Syria.

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 29% 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 mining project, which constitutes approximately 20% of total Mining contingent resources, and determined it to be economic, insofar as the project's estimated return on investment would significantly exceed returns currently available on secure, money-market investments. The economic status of remaining Mining contingent resources is currently undetermined.

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 project sanctioning based on development plans currently being reviewed awaits decision by the respective co-owners of the projects, 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 project sanction decisions by Suncor's Board and/or co-owners, as applicable, are considered.

In Situ Contingent Resources

In Situ contingent resources comprise approximately 53% of Suncor's total contingent resources, with 83% 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 83% of the contingent resources are in, or adjacent to, existing Firebag or MacKay River 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.

All In Situ contingent resources are associated with clastic or sandstone formations in the McMurray oil sands area. Suncor also owns mineral rights in 288 sections of the Grosmont carbonate formation, all at a 100% working interest. Core hole drilling completed on these sections has identified bitumen in the Grosmont, Upper Ireton and Nisku carbonate formations. In addition, Suncor has acquired the data from numerous third-party pilots currently in operation in the Grosmont carbonates. However, Suncor has not recognized any contingent resources in these carbonate formations, as Suncor believes that the viability of potential recovery processes has not been established.

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. These volumes have not been classified as 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 Firebag and MacKay River operations full.

Contingent resources for other In Situ properties (Chard, Kirby, Lewis, Meadow Creek and MacKay River) were assigned to sections with core holes, or lands within two legal subdivisions of a delineation well and net continuous bitumen pay greater than 15 metres. Prior to reserves being assigned, these contingent resources require the completion of further reservoir studies and delineation drilling, and the preparation of development plans and facility designs. The company expects that an assessment of the economic viability of these contingent resources will be undertaken as the company's long-term plans for its upgrading facilities 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. Certain contingent resources associated with 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/or co-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 18% 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, resources in the Montney formation in northeast B.C., the Arctic Islands, the Mackenzie Delta and Corridor, the Alaska Foothills, and several areas of Alberta.
- For East Coast Canada, Hebron and extensions of existing producing oilfields, 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 and the U.K.
- For Other International, volumes associated with the company's suspended operations in Syria and, in Libya, undeveloped portions within existing producing fields and other discovered hydrocarbon accumulations that are not currently producing.

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 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 viability of contingent resources in the Montney shale gas formation will be assessed subsequent to further delineation drilling. The economic status of contingent resources associated with certain fields in the Arctic Islands is undetermined, but may 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 remote 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 Libya 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 co-owners, 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.

As a result of the suspension of Suncor's operations in Syria, volumes previously classified as reserves have been reclassified to contingent resources. For these resources to be reclassified as reserves, sanctions that are applicable to Suncor and that were initiated as a result of political unrest in Syria must be lifted, and the overall political environment must improve and stabilize so that the company can resume business in Syria. In addition, if infrastructure including pipes and wells were damaged as a result of the political unrest, then the infrastructure will potentially need to be built again in order to reclassify the resources as reserves.

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. 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, affecting the ability to market crude oil and natural gas. In addition, oil and natural gas producers in North America, and particularly in Canada, currently receive discounted prices for their production relative to certain international prices, due to constraints on the ability to transport and sell such products to international markets.

Recently, pipeline capacity to support the growth of the oil and natural gas industry in Canada has been the subject of political and environmental debate. Suncor supports the responsible development of additional 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, which are subject to change as a result of numerous factors, including political considerations, 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 15% for active business income, including resource income. The average provincial income tax rate for Suncor in 2012 was 10.67%.

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. sector 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 in the 2012 audited Consolidated Financial Statements 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 respective PSCs. All government interests in these 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 gas 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, grants 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, PSCs 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 Suncor in the same manner as they apply to other international companies and enterprises in the energy industry. The regulatory regimes require Suncor 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 regulatory 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, Suncor expects 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, and the Lower Athabasca Regional Plan (LARP) that implements a cumulative efforts management regime in the Athabasca oil sands region. These statutes, regulations and frameworks relate to such issues as tailings management, water use, air emissions 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 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.

International Climate Change Agreements and Treaties

In 2012, the Government of Canada announced that it would not sign up for the second Kyoto Commitment Period commencing 2013. However, Canada has committed, pursuant to an agreement at the United Nations Framework Convention on Climate Change (UNFCCC) Conference of the Parties held in Copenhagen, Denmark in 2009 (Copenhagen Accord), to reducing its GHG emissions by 17% below 2005 levels by 2020, in line with the reduction commitment made by the U.S. The Copenhagen Accord does not contain any binding commitments for reducing CO_2 emissions, nor does it include any discussion of compliance mechanisms. Canada has also supported an outcome of the 2010 UNFCCC Conference of the Parties, held in Durban, which commits all parties to a process for a global GHG mitigation regime starting in 2020. Negotiations on that commitment period and associated individual country targets are to conclude by 2015.

Canadian Federal GHG Regulations

The Canadian federal government continues to address emissions of specific sectors of the economy, so far having concluded the implementation of 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 gasoline supply come from renewable sources such as ethanol and that 2% of diesel supply come from bio-diesel. The Canadian federal government is engaged in negotiations with the Canadian oil and gas industry on proposed regulations for the sector. It is currently expected that the provincial governments will enter into equivalency agreements for their own regulations with regard to a future federal regulation.

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. For 2011, the total cost to comply with the Alberta regulations was approximately $8 million. Compliance in 2011 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 2013, Suncor expects to file compliance reports that show what actions the company took during 2012 to demonstrate that each facility either met its intensity target or took action to offset its emissions intensity. For the compliance period of January 1 to December 31, 2012, 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 2012. Future costs may be subject to change, given that, in late 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, whose members also include individual U.S. states, created in 2007 to address climate change.

The Province of British Columbia enacted a carbon tax in 2008, which began at $10/tonne of CO_{2e} and escalated at $5/tonne per year until 2012 when it reached its expected 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 2012, Quebec approved 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 deemed 2012 a transition year, with no cap imposed. Allowances and offsets are fungible across the WCI, such that Quebec-issued allowances and offsets 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 replaced by the cap-and-trade system.

Ontario is also a member of the WCI and implemented mandatory reporting regulations beginning with 2010 emissions and is currently engaging stakeholders on the development of a GHG reduction program for Ontario's industrial sector, intended to achieve equivalency with federal government regulation.

U.S. GHG Regulations

In an effort to build a green economy, the President of the United States has supported 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 the absence of other federal legislation on GHG emissions, the President is pressing ahead by endorsing the U.S. Environmental Protection Agency (EPA) to regulate GHG emissions under the Clean Air Act, starting with the thermal power sector. The implications of the oil and gas 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 of $CO2_e$ per year) facilities, which includes Suncor's Commerce City refinery. Suncor expects that the EPA will more aggressively pursue these initiatives in 2013, on the heels of the 2012 U.S. Presidential election.

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. The State of California has appealed the ruling and is awaiting the outcome of the appeal.

International Regulations

Phase III (2008-2012) of the European Union Emissions Trading Scheme (EU ETS), which is scheduled to begin in 2013 and will run until 2020, impacts Suncor's non-operated offshore assets 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 will include a transition from gratis allocation to auctioning allowances.

Land Use

In 2012, the Government of Alberta approved the LARP, which covers land use restrictions in the Lower Athabasca region of Alberta, which includes leases in Suncor's Oil Sands segment. The LARP, developed as part of the Land-Use Framework (LUF) under the Alberta Land Stewardship Act, identifies new conservation areas, as well as management frameworks to ensure the continued 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, including the use of environmental cumulative effects management on a regional scale, and may require Suncor to have greater participation in the evaluation of environmental issues. The frameworks include the following:

- **Air quality.** 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. Regulatory actions will occur when triggers or limits are reached or exceeded.
- **Surface water quality.** 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. Regulatory actions will occur when triggers or limits are reached or exceeded.
- **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 or exceeded.

Reclamation and Tailings

In February 2009, the Energy Resources Conservation Board (ERCB) of Alberta 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'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 the Millennium and North Steepbank areas. Syncrude's tailings management plan was approved by the ERCB in 2010 and incorporates a multi-pronged approach that includes freshwater capping, composite tailings technology (accelerates water from tailings with additives), and the separation of water and tailings through the use of centrifuges.

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 remediation and surface reclamation work at their mine sites, and for the 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. The MFSP has been designed by the Government of Alberta to include a periodic review of the program to ensure it is functioning properly and provide early warning of any potential risks. A review is scheduled to occur in 2013.

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 information regarding the quantity of fluids and additives, and other Provinces of Canada have, or have indicated that they will in the future, apply similar reporting requirements.

While hydraulic fracturing 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. OSLI is currently focused on land stewardship, water use, technology innovation and sustainable communities.

In 2012, Suncor worked with other companies towards the creation of Canada's Oil Sands Innovation Alliance (COSIA), which is committed to collaborative action to accelerate improvements in environmental performance, including tailings, water, land and GHG emissions. COSIA will build on the work of OSLI and other collaborative networks to share knowledge and expertise about new technologies and innovation related to environmental performance.

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 initiatives, such as our role in OSLI. For further information, please see our Sustainability Report at www.suncor.com.

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 holds 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 EH&S. The committee also reviews the effectiveness with which Suncor establishes appropriate EH&S policies, including GHG performance and emissions reduction plans given legal, industry and community standards. Management systems are maintained by this committee to implement such policies and ensure compliance with them.

RISK FACTORS

Suncor is committed to a proactive program of enterprise risk management intended to enable decision-making through consistent identification of risks inherent to its assets, activities and operations. 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. Risks facing Suncor's business are listed below.

Volatility of Commodity Prices and Light/Heavy Differentials

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), pipeline constraints, regional and international supply and demand imbalances, 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 bitumen in future years, due mainly to production growth from 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 and imbalances (whether as a result of pipeline constraints or otherwise). Heavy crude oil generally 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, and this price differential can be amplified due to supply and demand imbalances, as has been experienced over the last twelve months, due primarily to pipeline constraints and the inability to efficiently bring products to market. The price differential between light crude and WCS is particularly important for Suncor. 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. For the reasons noted above, the price differential between light crude and WCS in 2012 was at its widest level since 2008. Future light/heavy differentials are uncertain and continued widening of these differentials could have a negative impact on our business, especially price realizations for WCS and bitumen that Suncor is unable to upgrade or process at its refineries.

Refined petroleum product prices and refining margins are also affected by, among other things, crude oil prices, the availability of crude oil and other feedstock, 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. Constrained market access for oil sands production due to insufficient pipeline takeaway capacity, growing inland production and refinery outages create risk of widening differentials or shut-in of production that could have a material adverse effect on our business, financial condition, results of operations and cash flow. In addition, oil and natural gas producers in North America, and particularly in Canada, currently receive discounted prices for their production relative to certain international prices, due to constraints on the ability to transport and sell such products to international markets. A failure to resolve such constraints may result in continued discounted or reduced commodity prices realized by oil and natural gas producers such as Suncor. 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 from some properties and/or the impairment of that property's 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, and may also lead to impairments or write-offs of the values of Suncor's assets or projects in development.

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 or interpretation thereof, 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 (which have since been lifted) 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, including opposition to new North American pipeline systems, such as the Keystone XL or the Northern Gateway proposals, 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. The company 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. Through industry associations, Suncor participates, both directly and indirectly, in the consultation process for the design of proposed regulations and other efforts to harmonize regulations across jurisdictions within North America.

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 intensity of its GHG emissions, the absolute GHG emissions of our company will continue to rise as we pursue a prudent and planned growth strategy.

As part of its ongoing business planning, Suncor assesses potential costs associated with CO_2 emissions in its evaluation of future projects, based on the company's 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, the company expects 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 its strategy, using a price range of \$15-\$60 per tonne of CO_2 equivalent as a base case, applied against a range of regulatory policy options and price sensitivities.

The Canadian federal government has indicated a preference for a sector-specific approach to climate change regulation; 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 in the absence of detail on how systems will operate.

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 its 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.

Land Reclamation

There are risks associated specifically with the company's 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 of technology and the time to reclaim tailings ponds could increase or decrease Suncor's decommissioning and restoration cost estimates. The company's failure or inability to adequately implement its reclamation plans could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

Alberta's Land-Use Framework

Alberta's LUF has been implemented under the Alberta Land Stewardship Act (ALSA), which sets out the Government of Alberta's approach to managing Alberta's land and natural resources to achieve long-term economic, environmental and social goals. ALSA contemplates the amendment or extinguishment of previously issued consents such as regulatory permits, licences, approvals and authorizations in order to achieve or maintain an objective or policy resulting from the implementation of a regional plan.

On August 22, 2012, the Government of Alberta approved the LARP, the first regional plan under the LUF. The LARP identifies management frameworks for air, land, water and biodiversity that will incorporate cumulative limits and triggers, as well as identifying areas related to conservation, tourism and recreation.

The implementation of, and compliance with, the terms of the LARP may adversely impact our current properties and projects in northern Alberta due to, among other things, environmental limits and thresholds. Due to the cumulative nature of the plan, the impact of the LARP on Suncor's operations may be outside of the control of the company, as Suncor's operations could be impacted as a result of restrictions imposed due to the cumulative impact of development in the area and not solely in relation to Suncor's direct impact.

Alberta Environment Water Licences

We currently rely on fresh water, which is obtained under licences from Alberta Environment to provide domestic and utility water at our Oil Sands operations. There can be no assurance that the licences to withdraw water will not be rescinded or that additional conditions will not be added to these licences. There can be no assurance that the company will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of the company's projects relies on securing licences for additional water withdrawal, and there can be no assurance that these licences will be granted on terms favourable to Suncor, or at all, or that such additional water will in fact be available to divert under such licences.

Income Taxes

In January 2013, the company received a proposal letter from the Canada Revenue Agency (CRA) relating to the income tax treatment of realized losses in 2007 on the settlement of Buzzard derivative contracts. The company strongly disagrees with the CRA's position and will respond to the proposal letter; however, the CRA may proceed to issue a notice of reassessment (NOR) to increase the amount payable by approximately $1.2 billion. The company firmly believes it will be able to successfully defend its original filing position so that ultimately no increased income tax payable will result from the CRA's actions. However, notwithstanding the filing of an objection to dispute this matter, the company would be required to make a minimum payment of 50% of the amount payable under the NOR, estimated to be $600 million, which would remain on account until the dispute is resolved.

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 Oil Sands Base mining operations, the Suncor BVM is based on the terms of the Suncor RAA, which modifies the application of the Suncor BVM as recently enacted by requiring additional quality and transportation adjustments. Suncor has 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 the Suncor RAA. Suncor has also filed with the Alberta government a Notice of Commencement of Arbitration under the Suncor RAA. The co-owners of Syncrude 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, including risks around the current negotiations with the NOC on the period in which Suncor was in force majeure under its EPSAs;
- 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 response to international sanctions and escalating political unrest in Syria, Suncor declared force majeure in December 2011, withdrew its expatriate staff and stopped recording production from Syria. Since this time, the company's prospects for resuming operations in Syria have not improved. As a result, Suncor recorded impairment charges against its assets in Syria during 2012. There is no assurance as to if or when Suncor's operations in Syria will resume or return to previous levels.

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. Suncor 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 Suncor will be successful in protecting itself against these risks and the related financial consequences.

Operational Outages and Major Environmental or Safety Incidents

Each of Suncor's 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, Suncor's 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 Suncor's 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. The company is also subject to operational risks such as sabotage, terrorism, trespass, theft and malicious software or network attacks.

The efficient operation of Suncor's 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, some of Suncor's 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 the company expects to further mitigate adverse impacts of interdependent systems and to reduce the production and cash flow impacts of complete plant-wide shutdowns. For example, the company expects the MNU will stabilize secondary upgrading processes by providing flexibility during planned or unplanned maintenance.

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.

Suncor's 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. Suncor's offshore operations could also be affected by the actions of Suncor's 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 the company's 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), the company may have to reduce production rates at its 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. In 2012, harsh weather conditions delayed the company's efforts to reconnect flow lines to drill centres for Terra Nova subsequent to a dockside maintenance program for the FPSO.

Suncor's 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 the company maintains 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.

EH&S Regulatory Non-Compliance

The company is required to comply with a large number of EH&S regulations under a variety of Canadian, U.S., U.K. and other foreign, federal, provincial, territorial, state and municipal laws and regulations, some of which are 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.

Project Execution

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.

In addition, there are certain risks associated with the execution of our exploration, production and refining projects. These risks include, but are not limited to:

- Our ability to obtain the necessary environmental and regulatory approvals;
- Risks relating to scheduling, resources and costs, including the availability and cost of materials, equipment and qualified personnel;
- The impact of general economic, business and market conditions;
- The impact of weather conditions;
- The accuracy of project cost estimates;
- Our ability to finance growth;
- Our ability to source or complete strategic transactions;

- The effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment; and
- The commissioning and integration of new facilities within our existing asset base could cause delays in achieving guidance, targets and objectives.

The failure to sanction or build a project could result in additional costs, including abandonment and reclamation costs, to shutdown the project, and such costs could be material to Suncor.

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 arrangements 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. 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. Suncor is exposed to the risk of escalating operating costs in both its oil sands business and other businesses, 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.

Co-owner Management

Suncor has entered into joint arrangements and other contractual arrangements with third parties with respect to certain of its projects where other entities operate assets in which Suncor has ownership or other interests. Suncor's dependence on its co-owners and its constrained 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 and projects operated by others, or developed jointly with 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 co-owners may have objectives and interests that do not coincide with and may conflict with Suncor's interests. Major capital decisions affecting joint arrangements may require agreement among the co-owners, 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 and the development of projects, no assurance can be provided that the future demands or expectations of the parties relating to such assets and projects will be met satisfactorily or in a timely manner. Failure to satisfactorily meet demands or expectations by all of the parties may affect our participation in the operation of such assets or in the development of such projects, our ability to obtain or maintain necessary licences or approvals, or the timing for undertaking various activities. In addition, disputes may arise pertaining to the timing and/or capital commitments with respect to projects that are being jointly developed, which could materially adversely affect the development of such projects and Suncor's business and operations.

Exchange Rate Fluctuations

Our 2012 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 30% 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 jointly owned facilities operated by another entity could have a material adverse effect on Suncor's business, financial condition, results of operations and cash flow.

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 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.

Energy Trading and Risk Management Activities and the Exposure to Counterparties

The nature of Suncor's energy trading and risk management activities, which may make use of derivative financial instruments to hedge its commodity price and other market risks, 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.

The terms of derivative financial instruments may also 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, 2012, our CEO 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,* as amended (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, 2012, there were no changes in our internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) that occurred during the year ended December 31, 2012 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 assets in these countries, including whether certain facilities have suffered damage. Suncor is continually assessing the control environment in these countries to the extent permitted by applicable law and does not consider the changes in these countries to have had a material impact on the company's overall internal control over financial reporting.

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, 2012, we had approximately $4.7 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 2013. If cash flow from operations is lower than expected, if capital expenditures in 2013 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 Articles of Suncor (the 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 $6.3 billion in credit facilities ($4.7 billion unused), the majority of which matures in 2016, with the remainder maturing in 2013 and 2014, or on demand. At December 31, 2012, Suncor's total debt was $11.0 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.

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. 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 $0.13 per share from $0.11 per share in the second quarter of 2012. 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	2012	2011	2010
Cash dividends per common share ($)	0.50	0.43	0.40

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, 2012, there were 1,523,056,848 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, 2012. 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)	Baa1	Stable	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. The R-1 and R-2 commercial paper categories are denoted by (high), (middle) 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.

Suncor has paid each of S&P, DBRS and Moody's their customary fees in connection with the provision of the above ratings. Suncor has not made any payments to S&P, DBRS or Moody's in the past two years for services unrelated to the provision of such ratings.

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 for the year ended December 31, 2012, are as follows:

TSX

	Price Range (Cdn$)		Trading Volume
	High	Low	(000's)
2012			
January	34.87	30.07	91 700
February	37.28	33.41	92 338
March	35.94	31.73	98 223
April	33.23	29.40	79 618
May	33.39	27.28	96 010
June	30.25	26.97	95 117
July	32.05	28.43	69 719
August	32.55	30.10	56 846
September	34.83	30.50	72 555
October	34.09	32.14	59 827
November	34.99	31.23	54 657
December	33.01	31.50	51 901

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 2012, see the Share Capital note to the 2012 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.

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.

Suncor Directors Name and Jurisdiction of Residence	Period Served and Independence	Biography
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. In addition, he is a member of the Order of Canada, 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.
Paul Haseldonckx[(2)(3)] Essen, Germany	Director since 2009 (Petro-Canada 2002 to July 31, 2009) Independent	Paul Haseldonckx was 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. and as a director of Hi Crush Partners LP.
Jacques Lamarre[(2)(3)] 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. Mr. Lamarre is also a director of the Institute of Corporate Directors — Quebec Chapter.
Maureen McCaw[(1)(2)] Alberta, Canada	Director since 2009 (Petro-Canada 2004 to July 31, 2009) Independent	Maureen McCaw is past Executive Vice-President (Edmonton) of Leger Marketing, formerly Criterion Research Corp., a company she founded in 1986. Ms. McCaw holds a Bachelor of Arts from the University of Alberta and an Institute of Corporate Directors certification (ICD.D). In addition to being president of Tinnakilly Inc. and a managing partner at Prism Ventures, Maureen is a director of the Canadian Broadcasting Corporation (CBC), the Edmonton International Airport, as well as a member of the Alberta Securities Commission. Maureen also serves on a number of Alberta boards and advisory committees, including Women Building Futures, the Nature Conservancy of Canada (Alberta) and Royal Alexandra Hospital and is past chair of the Edmonton Chamber of Commerce.
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. He has previously served on the boards of Teresen Inc., Primewest Energy Inc. and CRA International.
James Simpson[(1)(4)] Alberta, Canada	Director since 2009 (Petro-Canada 2004 to July 31, 2009) Independent	James Simpson 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.

Suncor Directors Name and Jurisdiction of Residence	Period Served and Independence	Biography
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., Dundee Precious Metals Inc. and Kaminak Gold Corporation. 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 President of Suncor Energy Inc. since December 2011 and as Chief Executive Officer of Suncor Energy Inc. since May 2012. Mr. Williams is a fellow of the Institution of Chemical Engineers and is a member of the Institute of Directors. He is also co-chair of the Oil Sands Leadership Initiative (OSLI), one of 12 founding CEOs in Canada's Oil Sands Innovation Alliance (COSIA), a member of the Canadian Council of Chief Executives and a member of the Business Advisory Council, School of Business at the University of Alberta. In October 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
Steven W. Williams	Alberta, Canada	President and Chief Executive 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 February 10, 2013, the directors and executive officers of Suncor as a group beneficially owned, or controlled or directed, directly or indirectly, common shares of Suncor representing 0.04% of 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 company 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; 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 Mr. Ford, a director of Suncor who is currently a director of USG Corporation, which was in bankruptcy protection until June 2006 and who was also a director of United Airlines (until February 2006), which was in Chapter 11 bankruptcy protection until February 2006.

(b) 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.

To the best of our knowledge, 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. Lamarre, 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 our 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 2012 and 2011, the nature of which are described below, were as follows:

($ thousands)	2012	2011
Audit Fees	5 904	6 145
Audit-Related Fees	429	423
Tax Fees	50	50
All Other fees	125	9
Total	6 508	6 627

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 audits of joint arrangements 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. All services described beside the captions "Audit Fees", "Audit Related Fees", "Tax Fees" and "All Other Fees" were approved by the Audit Committee in compliance with paragraph (c)(7)(i) of Rule 2-01 of Regulation S-X under the U.S. Securities and Exchange Act of 1934, as amended (the Exchange Act). None of the fees described above were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Regulation S-X under the Exchange Act.

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 most recently completed 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 interest, direct or indirect, in any transaction or any proposed transaction that has materially affected or is reasonably expected to materially affect us 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, 2012, 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. 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.

The Corporation's independent auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have issued an independent auditor's report dated February 26, 2013 in respect of the Corporation's consolidated financial statements, which comprise the consolidated balance sheets as at December 31, 2012 and December 31, 2011 and the consolidated statements of comprehensive income, changes in shareholders' equity and cash flows for the years ended December 31, 2012 and December 31, 2011, and the related notes, and the Corporation's internal control over financial reporting as at December 31,

2012. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and the rules of the United States Securities and Exchange Commission.

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's rules and instead may comply with Canadian requirements. As a foreign private issuer, we are only required to comply with four of the NYSE's rules. These rules provide that: (i) Suncor must have an audit committee that satisfies the requirements of Rule 10A-3 under the Exchange Act; (ii) the Chief Executive Officer of Suncor must promptly notify the NYSE in writing after an executive officer becomes aware of any material non-compliance with the applicable NYSE rules; (iii) Suncor must 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) Suncor must 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 Exchange Act), 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, and securities authorized for issuance under equity compensation plans, 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 2012 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 information and forward-looking statements (collectively referred to herein as "forward-looking statements") within the meaning of applicable Canadian and U.S. securities laws. Forward-looking statements and other information is 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", "will", "estimates", "plans", "scheduled", "intends", "believes", "projects", "indicates", "could", "focus", "vision", "goal", "outlook", "proposed", "target", "objective", "continue", "should", "may" 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 that:

- *The MNU will increase sweet SCO production capacity by approximately 10%, and stabilize secondary upgrading processes by providing flexibility with respect to hydrogen production during planned or unplanned maintenance;*
- *The debottlenecking project of existing central processing facilities at MacKay River that will increase bitumen processing capacity to 38,000 bbls/d;*
- *The TRO_{TM} process is expected to accelerate and improve the company's tailings management processes, eliminate the need for new tailings ponds at existing mining operations, and, in the years ahead, reduce the number of tailings ponds presently in operation;*
- *Suncor's plans to develop the majority of its conventional proved undeveloped reserves over the next five years and the majority of its conventional probable undeveloped reserves over the next seven years, subject to certain exemptions;*
- *Production estimates for 2013, including that total production from Firebag will increase to approximately 180,000 bbls/d over the next year; and*
- *The company's expectation that, as production from Firebag increases, the Firebag SOR will decrease.*

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

- *the third drill centre at Terra Nova is expected to be reconnected in the third quarter of 2013, when damaged flow lines can be replaced.*

Suncor's expectations about capital expenditures and growth and other projects, including:

- *The first two of four new storage tanks in Hardisty, Alberta, will connect to the Enbridge mainline pipeline in 2013;*
- *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;*
- *Plans for centrifuge technology at Syncrude that separates water from tailings;*
- *Preliminary designs for the Fort Hills mining project plan for 164,000 bbls/d of bitumen production (gross) and for the Joslyn mining project plan for 100,000 bbls/d of bitumen production (gross);*
- *Development plans for Terra Nova which will include a production well and a water injection well that the company anticipates will add production and mitigate natural declines from the reservoir, and a development well in the West Flank area of the oilfield in 2013;*
- *Development plans for the HSEU, which include drilling up to two additional production wells and five water injection wells in a subsea glory hole, and that production from the HSEU is not expected to reach higher rates until the planned water injection wells are completed;*
- *Development plans for the White Rose Extensions;*
- *Plans for Hebron that include a concrete GBS, integrated topsides deck, 1,200,000 bbls of oil storage capacity, 52 well slots and a gross oil production capacity of 150,000 bbls/d (net 34,000 bbls/d to Suncor), and the company's expectations that first oil will occur in late 2017;*
- *Suncor's share of project costs for the Hebron project will be approximately $3.2 billion;*
- *Development plans for Golden Eagle, which include an initial gross production rate of 70,000 boe/d (gross) from 20 development wells, development costs 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 acquisition of new seismic data in 2013 and further appraisal drilling in 2014 for the Beta discovery;*
- *Plans to drill two additional exploration wells for the Butch prospect offshore Norway and one exploration well for the Scotney prospect offshore the U.K.; and*
- *Suncor's plans to restart exploration activities in Libya in 2013, the estimated remaining cost of US$275 million as at December 31, 2012 for its exploration program in Libya, and that the remaining obligation related to the EPSA signature bonus will be paid over the next three years.*

Also:

- *The plan by Syncrude owners to develop mining areas adjacent to the current mine that would extend the life for Mildred Lake by approximately 10 years, and that Syncrude expects to make regulatory applications for these areas in 2014;*

- *The plan for Suncor to pursue opportunities to divest non-core properties in its North American Onshore operations that meets its financial objectives;*
- *Sanctioning decisions around the Fort Hills, Voyageur and Joslyn projects;*
- *Significant development activities anticipated to occur in 2013;*
- *Anticipated abandonment and reclamation costs;*
- *Anticipated royalty and income tax rates and the impact of these rates on Suncor;*
- *Anticipated effects of environmental and climate change legislation, including 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 plans around its resources;*
- *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 2013;*
- *Suncor's belief that existing cash balances, internally generated cash flows and existing credit facilities are sufficient to fund future development costs and that interest or other funding costs would not make development of any property uneconomical;*
- *Suncor's estimates for its compliance costs for GHG regulations in Alberta for 2012 will be between $10 million and $15 million;*
- *Suncor's belief that it will be able to successfully defend its original filing position in relation to the Buzzard derivative contracts so that ultimately no increased income tax payable will result from CRA's position; 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 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, and 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 used 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 Alberta's Wood Buffalo region 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 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 the 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 or reassessment 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; and 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. 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 the company.

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:

(a) 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.

(b) 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.

(c) 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

(d) 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, 2012

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; and

(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, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2012, 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, 2012, 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 ($ millions, discounted at 10%)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	Oil Sands In Situ January 18, 2013	Canada	—	16 033	—	16 033
GLJ Petroleum Consultants Ltd.	Oil Sands Mining January 7, 2013	Canada	—	22 108	—	22 108
			—	**38 141**	**—**	**38 141**

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, 2013

"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, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2012, 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, 2012, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and Board of Directors:

			Net Present Value of Future Net Revenues Before Income Taxes ($ millions, discounted at 10%)			
Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	East Coast Canada February 20, 2013	Newfoundland Offshore, Canada	—	7 815	—	7 815
Sproule Associates Limited	North America Onshore February 20, 2013	Western Canada	—	1 795	—	1 795
Sproule International Limited	North Sea February 20, 2013	North Sea, United Kingdom	—	8 193	—	8 193
Sproule International Limited	Other International February 20, 2013	Libya	—	4 196	—	4 196
			—	**21 999**	**—**	**21 999**

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, 2013

"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 OIL AND GAS DISCLOSURE

Management of Suncor Energy Inc. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2012, 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.

"*Steven W. Williams*"
STEVEN W. WILLIAMS
President and 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, 2013

Suncor Energy Inc.
150 - 6 Avenue S.W., Calgary, Alberta, Canada T2P 3E3
T: 403-296-8000

Suncor.com