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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(Check One)

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

or

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

For fiscal year ended: December 31, 2012
Commission File Number: No. 1-12384

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

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

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

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

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

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

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

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

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

None

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

None

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

ý Annual Information Form ý Annual Audited Financial Statements

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

Common Shares	**As of December 31, 2012 there were 1,523,056,848 Common Shares issued and outstanding**
Preferred Shares, Series A	**None**

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

Yes ý No o

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

Yes o No o

INCORPORATION BY REFERENCE

The Registrant's Annual Information Form dated March 1, 2013, included in this annual report on Form 40-F, and Audited Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2012, included as Exhibit 99-1 and Exhibit 99-2, respectively, to this annual report on Form 40-F, are incorporated by reference into and as an exhibit to, as applicable, each of the Registrant's Registration Statements under the Securities Act of 1933: Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029) and Form F-9 (File No. 333-181421).

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 m^3 natural gas = 35.49 cubic feet

1 kilometre = 0.62 miles
1 hectare = 2.5 acres

(1) Conversion using the above factors on rounded numbers appearing in this AIF may produce small differences from reported amounts.

(2) Some information in this AIF is set forth in metric units and some in imperial units.

CORPORATE STRUCTURE

Name and Incorporation

Suncor Energy Inc. (formerly Suncor Inc.) was originally formed by the amalgamation under the *Canada Business Corporations Act* on August 22, 1979, of Sun Oil Company Limited, incorporated in 1923, and Great Canadian Oil Sands Limited, incorporated in 1953. On January 1, 1989, we further amalgamated with a wholly owned subsidiary under the *Canada Business Corporations Act*. We amended our articles in 1995 to move our registered office from Toronto, Ontario, to Calgary, Alberta, and again in April 1997 to adopt our current name, "Suncor Energy Inc.". In April 1997, May 2000, May 2002, and May 2008, we amended our articles to divide the issued and outstanding shares on a two-for-one basis.

Pursuant to an arrangement (the Arrangement), which was completed effective August 1, 2009, Suncor amalgamated with Petro-Canada to form a single corporation continuing under the name "Suncor Energy Inc.", 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 - 6 th Avenue, S.W., Calgary, Alberta, T2P 3E3.

Intercorporate Relationships

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

- **TRO_{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 TRO_{TM} treatment, and (c) pump treated water from tailings ponds back to extraction plants for use in production processes. Through the TRO_{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		Sarnia		Edmonton		Commerce City	
	2012	2011	2012	2011	2012	2011	2012	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		Sarnia		Edmonton		Commerce City	
	2012	2011	2012	2011	2012	2011	2012	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™ brand. As at December 31, 2012, the Petro-Canada™ 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.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The Statement of Reserves Data and Other Oil and Gas Information outlined below is dated March 1, 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.

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

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$)		
	High	Low	Trading Volume (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.

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.

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:

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
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

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

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

B. Consent to Service of Process

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

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

See pages 83 and 84 of Exhibit 99-1 and page 73 of Exhibit 99-2.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See pages 85 and 86 of Exhibit 99-1.

AUDIT COMMITTEE FINANCIAL EXPERT

See pages 76 and 77 of Annual Information Form.

CODE OF ETHICS

See pages 25 and 79 of Annual Information Form.

FEES PAID TO PRINCIPAL ACCOUNTANT

See pages 77 and 78 of Annual Information Form.

AUDIT COMMITTEE PRE-APPROVAL POLICIES

See Schedule "B" of Annual Information Form.

APPROVAL OF NON-AUDIT SERVICES

See Schedule "B" of Annual Information Form.

OFF-BALANCE SHEET ARRANGEMENTS

See page 57 of Exhibit 99-2.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page 57 of Exhibit 99-2.

IDENTIFICATION OF THE AUDIT COMMITTEE

See page 76 of Annual Information Form.

SIGNATURES

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

SUNCOR ENERGY INC.

DATE: March 1, 2013

PER: /s/ BART W. DEMOSKY

Bart W. Demosky
Chief Financial Officer

EXHIBIT INDEX

Exhibit No.	Description
99-1	Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2012
99-2	Management's Discussion and Analysis for the fiscal year ended December 31, 2012, dated February 26, 2013
99-3	Consent of PricewaterhouseCoopers LLP
99-4	Consent of GLJ Petroleum Consultants Ltd.
99-5	Consent of Sproule Associates Limited, Sproule Unconventional Limited and Sproule International Limited
99-6	Certificate of the Chief Executive Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-7	Certificate of the Chief Financial Officer Pursuant to Exchange Act Rules 13a-14(a) or 15d-14(a)
99-8	Certificate of the Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99-9	Certificate of the Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

QuickLinks

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

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-1

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2012

MANAGEMENT'S STATEMENT OF RESPONSIBILITY FOR FINANCIAL REPORTING

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

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and Canadian generally accepted accounting principles as contained within Part 1 of the Institute of Chartered Accountants Handbook. They include certain amounts that are based on estimates and judgments.

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

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

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





Steve W. Williams
President and Chief Executive Officer

Bart W. Demosky
Chief Financial Officer

February 26, 2013

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

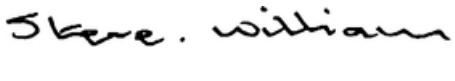
MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

3. Management has assessed the effectiveness of the company's internal control over financial reporting as at December 31, 2012, and has concluded that such internal control over financial reporting was effective as of that date. Additionally, based on this assessment, management determined that there were no material weaknesses in internal control over financial reporting as at December 31, 2012. Because of inherent limitations, systems of internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

4. The effectiveness of the company's internal control over financial reporting as at December 31, 2012 has been audited by PricewaterhouseCoopers LLP, independent auditor, as stated in their report which appears herein.





Steve W. Williams
President and Chief Executive Officer

Bart W. Demosky
Chief Financial Officer

February 26, 2013

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Suncor Energy Inc.

We have completed integrated audits of Suncor Energy Inc.'s 2012 and 2011 consolidated financial statements and its internal control over financial reporting as at December 31, 2012. Our opinions, based on our audits, are presented below.

Report on the consolidated financial statements

We have audited the accompanying consolidated financial statements of Suncor Energy Inc. ("the Company"), which comprise the consolidated balance sheets as at December 31, 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, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

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

Auditor's responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2012 and December 31, 2011 and its financial performance and its cash flows for the years ended December 31, 2012 and December 31, 2011 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on internal control over financial reporting

We have also audited the Company's internal control over financial reporting as at December 31, 2012, based on criteria established in Internal Control – Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Management's responsibility for internal control over financial reporting

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

Auditor's responsibility

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

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

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

Definition of internal control over financial reporting

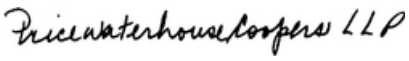
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal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

Inherent limitations

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

Opinion

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2012, based on criteria established in Internal Control – Integrated Framework issued by COSO.



Chartered Accountants
Calgary, Alberta
February 26, 2013

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 ($ millions)	**2012**	2011
Revenues and Other Income		
Operating revenues, net of royalties (note 6)	**38 208**	38 339
Other income (note 7)	**408**	453
	38 616	38 792
Expenses		
Purchases of crude oil and products	**17 101**	17 725
Operating, selling and general (notes 8 and 25)	**8 948**	8 424
Transportation	**685**	736
Depreciation, depletion, amortization and impairment (note 9)	**6 450**	3 952
Exploration	**309**	116
(Gain) loss on disposal of assets	**(44)**	136
Project start-up costs	**60**	163
Financing expenses (note 10)	**66**	471
	33 575	31 723
Earnings before Income Taxes	**5 041**	7 069
Income Taxes (note 11)		
Current	**1 515**	1 121
Deferred	**743**	1 644
	2 258	2 765
Net Earnings	**2 783**	4 304
Other Comprehensive Income (Loss)		
Foreign currency translation adjustment	**(16)**	230
Foreign currency translation reclassified to net earnings	**—**	14
Cash flow hedges reclassified to net earnings	**(1)**	—
Actuarial loss on employee retirement benefit plans, net of income taxes of $63 (2011 – $117)	**(177)**	(339)
Other Comprehensive Income (Loss)	**(194)**	(95)
Total Comprehensive Income	**2 589**	4 209
Per Common Share (dollars) (note 12)		
Net earnings – basic	**1.80**	2.74
Net earnings – diluted	**1.79**	2.67
Cash dividends	**0.50**	0.43

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

CONSOLIDATED BALANCE SHEETS

($ millions)	**December 31 2012**	December 31 2011
Assets		
Current assets		
Cash and cash equivalents (note 13)	**4 393**	3 803
Accounts receivable	**5 244**	5 412
Inventories (note 15)	**3 743**	4 205
Income taxes receivable	**799**	704
Total current assets	**14 179**	14 124
Property, plant and equipment, net (note 16)	**55 458**	52 589
Exploration and evaluation (note 17)	**3 284**	4 554
Other assets (note 18)	**320**	311
Goodwill and other intangible assets (note 19)	**3 128**	3 139
Deferred income taxes (note 11)	**80**	60
Total assets	**76 449**	74 777
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term debt (note 20)	**776**	763
Current portion of long-term debt (note 20)	**311**	12
Accounts payable and accrued liabilities	**6 469**	7 755
Current portion of provisions (note 23)	**856**	811
Income taxes payable	**1 170**	969
Total current liabilities	**9 582**	10 310
Long-term debt (note 20)	**9 938**	10 004
Other long-term liabilities (note 21)	**2 310**	2 392
Provisions (note 23)	**4 933**	3 752
Deferred income taxes (note 11)	**10 463**	9 719
Shareholders' equity	**39 223**	38 600
Total liabilities and shareholders' equity	**76 449**	74 777

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

Approved on behalf of the Board of Directors:



Steve W. Williams
Director

Michael W. O'Brien
Director

February 26, 2013

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ millions)	**2012**	2011
Operating Activities		
Net earnings	**2 783**	4 304
Adjustments for:		
Depreciation, depletion, amortization and impairment	**6 450**	3 952
Deferred income taxes	**743**	1 644
Accretion	**182**	157
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(181)**	183
Change in fair value of derivative contracts	**10**	(40)
(Gain) loss on disposal of assets	**(44)**	136
Share-based compensation	**214**	(102)
Exploration	**145**	28
Settlement of decommissioning and restoration liabilities	**(433)**	(496)
Other	**(124)**	(20)
(Increase) decrease in non-cash working capital (note 14)	**(899)**	242
Cash flow provided by operating activities	**8 846**	9 988
Investing Activities		
Capital and exploration expenditures	**(6 959)**	(6 850)
Acquisitions	**—**	(842)
Proceeds from disposal of assets	**68**	3 074
Proceeds from risk mitigation instruments	**300**	—
Other investments	**(3)**	(6)
(Increase) decrease in non-cash working capital (note 14)	**(51)**	26
Cash flow used in investing activities	**(6 645)**	(4 598)
Financing Activities		
Net change in short-term debt	**13**	(1 221)
Net change in long-term debt	**414**	(4)
Repayment of long-term debt	**—**	(500)
Issuance of common shares under share option plans	**188**	213
Purchase of common shares for cancellation, net of option premiums (note 24)	**(1 451)**	(500)
Dividends paid on common shares	**(756)**	(664)
Cash flow used in financing activities	**(1 592)**	(2 676)
Increase in Cash and Cash Equivalents	**609**	2 714
Effect of foreign exchange on cash and cash equivalents	**(19)**	12
Cash and cash equivalents at beginning of period	**3 803**	1 077
Cash and Cash Equivalents at End of Period	**4 393**	3 803
Supplementary Cash Flow Information		
Interest paid	**642**	672
Income taxes paid	**1 510**	885

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

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

($ millions)	Share Capital	Contributed Surplus	Foreign Currency Translation	Cash Flow Hedge	Retained Earnings	Total	Number of Common Shares (thousands)
At December 31, 2010	20 188	507	(451)	14	14 934	35 192	1 565 489
Net earnings	—	—	—	—	4 304	4 304	—
Foreign currency translation adjustment	—	—	244	—	—	244	—
Actuarial loss on employee retirement benefit plans	—	—	—	—	(339)	(339)	—
Total comprehensive income	—	—	244	—	3 965	4 209	—
Issued under share option plans	325	(57)	—	—	—	268	9 920
Issued under dividend reinvestment plan	12	—	—	—	(12)	—	355
Purchase of common shares for cancellation	(222)	—	—	—	(278)	(500)	(17 128)
Share-based compensation	—	94	—	—	—	94	—
Income tax benefit of stock option deduction in the U.S.	—	1	—	—	—	1	—
Dividends paid on common shares	—	—	—	—	(664)	(664)	—
At December 31, 2011	20 303	545	(207)	14	17 945	38 600	1 558 636
Net earnings	**—**	**—**	**—**	**—**	**2 783**	**2 783**	**—**
Foreign currency translation adjustment	**—**	**—**	**(16)**	**—**	**—**	**(16)**	**—**
Net change in cash flow hedges	**—**	**—**	**—**	**(1)**	**—**	**(1)**	**—**
Actuarial loss on employee retirement benefit plans	**—**	**—**	**—**	**—**	**(177)**	**(177)**	**—**
Total comprehensive income (loss)	**—**	**—**	**(16)**	**(1)**	**2 606**	**2 589**	**—**
Issued under share option plans	**255**	**(49)**	**—**	**—**	**—**	**206**	**10 804**
Issued under dividend reinvestment plan	**15**	**—**	**—**	**—**	**(15)**	**—**	**479**
Purchase of common shares for cancellation, net of option premiums (note 24)	**(609)**	**—**	**—**	**—**	**(842)**	**(1 451)**	**(46 862)**
Liability for share purchase commitment (note 24)	**(19)**	**—**	**—**	**—**	**(29)**	**(48)**	**—**
Share-based compensation	**—**	**83**	**—**	**—**	**—**	**83**	**—**
Dividends paid on common shares	**—**	**—**	**—**	**—**	**(756)**	**(756)**	**—**
At December 31, 2012	**19 945**	**579**	**(223)**	**13**	**18 909**	**39 223**	**1 523 057**

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

1. REPORTING ENTITY AND DESCRIPTION OF THE BUSINESS

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

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

2. BASIS OF PREPARATION

(a) Statement of Compliance

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and Canadian generally accepted accounting principles (GAAP) as contained within Part 1 of the Canadian Institute of Chartered Accountants Handbook.

The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as at February 26, 2013, the date the Board of Directors approved the statements.

(b) Basis of Measurement

The consolidated financial statements are prepared on a historical cost basis except as detailed in the accounting policies disclosed in note 3. The accounting policies described in note 3 have been applied consistently to all periods presented in these financial statements.

(c) Functional Currency and Presentation Currency

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

(d) Use of Estimates and Judgment

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

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Principles of Consolidation

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

(b) Foreign Currency Translation

Functional currencies of the company's individual entities represent the currency of the primary economic environment in which the entity operates. Transactions in foreign currencies are translated to the appropriate functional currency at foreign exchange rates that approximate those on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the appropriate functional currency at foreign exchange rates at the balance sheet date. Foreign exchange differences arising on translation are recognized in earnings. Non-monetary assets that are measured in a foreign currency at historical cost are translated using the exchange rate at the date of the transaction.

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

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

(c) Revenues

Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products and refined petroleum products is recorded when title passes to the customer and collection is reasonably assured. Revenue from properties in which the company has an interest with other producers is recognized on the basis of the company's net working interest. For operations not pursuant to production sharing contracts (PSCs), crude oil and natural gas sold below or above the company's working interest share of production results in production underlifts or overlifts. Underlifts are recorded as a receivable at market value with a corresponding increase to revenues, while overlifts are recorded as a payable at market value with a corresponding decrease to revenues. Revenue from oil and natural gas production is recorded net of royalty expense.

International operations conducted pursuant to PSCs are reflected in the consolidated financial statements based on the company's working interest. Under the PSCs, the company pays all exploration costs and a contractual share of costs to develop and operate the concessions. Each PSC establishes the exploration, development and operating costs the company is required to fund and establishes specific terms for the company to recover these costs (Cost Recovery Oil) and to share in the production profits (Profit Oil). Cost Recovery Oil is determined in accordance with a formula that is generally limited to a specified percentage of production during each fiscal year. Profit Oil is that portion of production remaining after deducting Cost Recovery Oil and is shared between the company and the respective government. Cost Recovery Oil and Profit Oil are reported as revenue when the sale of product to a third party occurs. Revenue also includes income taxes paid on our behalf by our government joint venture partners.

(d) Cash and Cash Equivalents

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

(e) Inventories

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

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

(f) Exploration and Evaluation Assets

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

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

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

(g) Property, Plant and Equipment

Property, Plant and Equipment are recorded at cost.

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

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

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

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

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

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

(h) Depreciation, Depletion and Amortization

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

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

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

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

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

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

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

(i) Goodwill and Other Intangible Assets

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

Other intangible assets include acquired customer lists and brand value.

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

(j) Impairment of Assets

Non-Financial Assets

Property, Plant and Equipment and Exploration and Evaluation assets are tested for indicators of impairment whenever events or changes in circumstance indicate that the carrying amount may not be recoverable. Exploration and Evaluation assets are also tested for impairment immediately prior to costs being transferred to Property, Plant and Equipment. Goodwill and intangible assets that have an indefinite useful life are tested at least annually for impairment.

If any indication of impairment exists, an estimate of the asset's recoverable amount is calculated as the higher of the fair value less costs to sell and value-in-use. In determining fair value less costs to sell, recent market transactions are taken into account, if available. In the absence of such transactions, an appropriate valuation model is used. Value-in-use is assessed using the present value of the expected future cash flows of the relevant asset. If the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets, the asset is tested as part of a CGU, which is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets.

An impairment loss is recognized in Depreciation, Depletion, Amortization and Impairment for the amount by which the carrying amount of the individual asset or CGU exceeds its recoverable amount.

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

Financial Assets

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

(k) Assets Held For Sale

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

(l) Provisions

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

Provisions are recognized for decommissioning and restoration obligations associated with the company's Exploration and Evaluation assets and Property, Plant and Equipment. Provisions for decommissioning and restoration obligations are measured at the present value of management's best estimate of the future cash flows required to settle the present obligation, using the credit-adjusted risk-free interest rate. The value of the obligation is added to the carrying amount of the associated asset and amortized over the useful life of the asset. The provision is accreted over time through charges to Financing Expenses with actual expenditures charged against the accumulated obligation. Changes in the future cash flow estimates resulting from revisions to the estimated timing or amount of undiscounted cash flows are recognized as a change in the decommissioning and restoration provision and related asset.

(m) Income Taxes

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

(n) Pensions and Other Post-Retirement Benefits

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

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

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

(o) Share-Based Compensation Plans

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

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

Share-based compensation awards that settle in cash or have the option to settle in cash or shares are accounted for as cash-settled plans. These are measured at fair value each reporting period using the Black-Scholes options pricing model, with the exception of performance share units, which are measured at fair value using the Monte-Carlo simulation approach. The expense is recognized over the vesting period, with a corresponding adjustment to liabilities. When awards are surrendered for cash, the cash settlement paid reduces the outstanding liability. When awards are exercised for common shares, consideration paid by the holder and the previously recognized liability associated with the options are recorded to Share Capital.

(p) Financial Instruments

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

Fair Value through Profit and Loss

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

Loans and Receivables

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

Held-to-Maturity

Non-derivative financial assets that the company has the intent and ability to hold until maturity are measured at amortized cost using the effective interest method.

Other Financial Liabilities

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

Available for Sale

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

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

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

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

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

(q) Hedging Activities

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

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

(r) Share Capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any tax effects. When the company repurchases its own common shares, share capital is reduced by the average carrying value of the shares purchased. The excess of the purchase price over the average carrying value is recognized as a deduction from Retained Earnings. Shares are cancelled upon purchase.

(s) Dividend Distributions

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

(t) Earnings per Share

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

Diluted earnings per share is calculated by adjusting the weighted-average number of common shares outstanding for dilutive common shares related to the company's share-based compensation plans. The number of shares included is computed using the treasury stock method. Options with tandem stock appreciation rights or cash payment alternatives are accounted for as cash-settled plans. As these awards can be exchanged for common shares of the company, they are considered potentially dilutive and are included in the calculation of the company's diluted net earnings per share if they have a dilutive impact in the period.

4. SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of financial statements in accordance with IFRS requires management to make estimates and judgments that affect reported assets, liabilities, revenues, expenses, gains, losses, and disclosures of contingencies. These estimates and

judgments are subject to change based on experience and new information. The financial statement areas that require significant estimates and judgments are as follows:

Oil and Gas Reserves and Resources

Measurements of depletion, depreciation, impairment and decommissioning and restoration obligations are determined in part based on the company's estimate of oil and gas reserves and resources. The estimation of reserves and resources is an inherently complex process and involves the exercise of professional judgment. All reserves and certain resources have been evaluated at December 31, 2012 by independent qualified reserves evaluators in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. The reserves and resources estimates are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook.

Oil and gas reserves and resources estimates are based on a range of geological, technical and economic factors, including projected future rates of production, projected future commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Estimates reflect market and regulatory conditions existing at December 31, 2012, which could differ significantly from other points in time throughout the year, or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Oil and Gas Activities

The company is required to apply judgment when designating the nature of oil and gas activities as exploration, evaluation, development or production, and when determining whether the initial costs of these activities are capitalized.

Exploration and Evaluation Costs

Certain exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. The company is required to make judgments about future events and circumstances and applies estimates to assess the economic viability of extracting the underlying resources. The costs are subject to technical, commercial and management review to confirm the continued intent to develop the project. Level of drilling success, or changes to project economics, resource quantities, expected production techniques, production costs and required capital expenditures, are important judgments when making this determination.

Development Costs

Management uses judgment to determine when exploration and evaluation assets are reclassified to Property, Plant and Equipment. This decision considers several factors, including the existence of reserves, appropriate approvals from regulatory bodies and the company's internal project approval processes.

Determination of Cash Generating Units

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

Asset Impairment and Reversals

Management applies judgment in assessing the existence of impairment and impairment reversal indicators based on various internal and external factors.

The recoverable amount of CGUs and individual assets is determined based on the higher of fair value less costs to sell or value-in-use calculations. The key estimates the company applies in determining the recoverable amount normally include estimated future commodity prices, expected production volumes, future operating and development costs, discount rates, tax rates, and refining margins. In determining the recoverable amount, management may also be required to make judgments regarding the likelihood of occurrence of a future event. Changes to these estimates and judgments will affect the recoverable amounts of CGUs and individual assets and may then require a material adjustment to their related carrying value.

Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of Exploration and Evaluation assets and Property, Plant and Equipment. Management applies judgment in assessing the existence and extent as well as the expected method of reclamation of the company's decommissioning and restoration obligations at the end of each reporting period.

Management also uses judgment to determine whether the nature of the activities performed are related to decommissioning and restoration activities or normal operating activities.

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

Employee Future Benefits

The company provides benefits to employees, including pensions and other post-retirement benefits. The cost of defined benefit pension plans and other post-retirement benefits received by employees is estimated based on actuarial valuation methods that require professional judgment. Estimates typically used in determining these amounts include, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, the return on plan assets, mortality rates and future medical costs. Changes to these estimates may have a material impact on the amounts presented.

Other Provisions

The determination of other provisions, including, but not limited to, provisions for royalty disputes, onerous contracts, litigation and constructive obligations, is a complex process that involves judgments about the outcomes of future events, the interpretation of laws and regulations, and estimates on timing and amount of expected future cash flows and discount rates.

Income Taxes

Management annually evaluates tax positions taken which could be subject to differing interpretations of applicable tax legislation. The company recognizes a tax provision when a payment to tax authorities is considered more likely than not. The company believes that adequate provisions have been made for all income tax obligations, although the results of audits and reassessments and changes in the interpretations of standards may result in a material increase or decrease in the company's assets, liabilities and net earnings.

Deferred Income Taxes

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

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

Control and Significant Influence

Control is defined as the power to govern the financial and operating decisions of an entity so as to obtain benefits from its activities and significant influence is defined as the power to participate in the financial and operating decisions of the investee. The assessment of whether the company has control, joint control, or significant influence over another entity requires judgment of the impact it has over the financial and operating decisions of the entity and the extent of the benefits it obtains.

Fair Value of Financial Instruments

The fair value of financial instruments is determined whenever possible based on observable market data. If not available, the company uses third-party models and valuation methodologies that utilize observable market data including forward commodity prices, foreign exchange rates and interest rates to estimate the fair value of financial instruments, including derivatives. In addition to market information, the company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk.

5. RECENTLY ANNOUNCED ACCOUNTING PRONOUNCEMENTS

Scope of a Reporting Entity

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

IFRS 10 creates a single consolidation model by revising the definition of control in order to apply the same control criteria to all types of entities, including joint arrangements, associates and structured entities. IFRS 11 establishes a principle-based approach to the accounting for joint arrangements by focusing on the rights and obligations of the arrangement and limits the application of proportionate consolidation accounting to arrangements that meet the definition of a joint operation. Arrangements that meet the definition of a joint venture are required to apply the equity method of accounting. IFRS 12 is a comprehensive disclosure standard for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities. IAS 27 has been amended to conform to the changes made in IFRS 10 but retains the guidance on separate financial statements. IAS 28 has also been amended to conform to the changes made in IFRS 10 and 11.

Retrospective application of these standards with relief for certain transactions is effective for fiscal years beginning on or after January 1, 2013, with earlier application permitted if all five standards are collectively adopted. The company has identified two existing joint arrangements in the Refining and Marketing segment that will be required to change from proportionate consolidation to equity accounting as a result of IFRS 11. This change will not have a material impact to the consolidated financial statements, but will result in the netting of revenues and expenses (2012 – approximately $100 million and $90 million, respectively) for these entities into Other Income. In addition, the company's net investment in these entities will be presented in Other Assets.

Financial Instruments: Recognition and Measurement

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

Fair Value Measurements

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

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IFRS 7 *Financial Instruments: Disclosures* and IAS 32 *Financial Instruments: Presentation* to clarify the current offsetting model and develop common disclosure requirements to enhance the understanding of the potential effects of offsetting arrangements. Retrospective application of amendments to IFRS 7 are effective for annual and interim periods starting on or after January 1, 2013 with earlier application permitted. Retrospective application of amendments to IAS 32 are effective for annual periods starting on or after January 1, 2014 with earlier application permitted. The adoption of these amended standards is not expected to have a material impact on the company's financial statements; however, expanded disclosures on financial instruments that are offset in the Consolidated Balance Sheets will be required.

Presentation of Items of Other Comprehensive Income

In June 2011, the IASB issued amendments to IAS 1 *Presentation of Items of Other Comprehensive Income* to group items presented within Other Comprehensive Income based on whether they may be subsequently reclassified to net earnings. The amendment is required to be retrospectively adopted for periods beginning on or after July 1, 2012. The company does not expect a significant change to its presentation of items of Other Comprehensive Income.

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 *Employee Benefits*, which revises the recognition, presentation and disclosure requirements for defined benefit plans. The revised standard requires immediate recognition of actuarial gains and losses in Other Comprehensive Income thereby eliminating the previous options that were available, changes the calculation and presentation of the interest cost component of annual pension expense and enhances the disclosure requirements for defined benefit plans. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2013, with early application permitted. The company anticipates a net incremental increase to expenses of approximately $50 million for 2012 as a result of these amendments.

Production Stripping Costs

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

6. SEGMENTED INFORMATION

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

- Oil Sands includes the company's operations in northeast Alberta to develop and produce synthetic crude oil and related products, through the recovery and upgrading of bitumen from mining and in situ operations. This segment also includes the company's joint interest in Joslyn North (35.75%) and Fort Hills (40.8%) mining projects and the Voyageur upgrader (51%) project as well as its 12% ownership interest in the Syncrude oil sands mining and upgrading joint venture, located near Fort McMurray, Alberta.
- Exploration and Production includes exploration and production of natural gas, crude oil and natural gas liquids in Western Canada, offshore activity in East Coast Canada, with interests in the Hibernia, Terra Nova, White Rose and Hebron oilfields, and the exploration and production of crude oil and natural gas in the United Kingdom (U.K.), Norway, Libya and Syria.
- Refining and Marketing includes the refining of crude oil products, and the distribution and marketing of these and other purchased products through retail stations located in Canada and the United States (U.S.), as well as a lubricants plant located in Eastern Canada.

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

Intersegment sales of crude oil and natural gas are accounted for at market values and included, for segmented reporting, in revenues of the segment making the transfer and expenses of the segment receiving the transfer. Intersegment balances are eliminated on consolidation. Intersegment profit will not be eliminated until the related product has been sold to third parties.

The company had no customer that individually represents 10% or more of the consolidated revenues for the year ended December 31, 2012 (2011 – one customer).

For the years ended December 31 ($ millions)	Oil Sands [1]		Exploration and Production		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
	2012	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011
Revenues and Other Income										
Gross revenues	**8 378**	8 583	**5 947**	6 293	**26 109**	25 657	**89**	77	**40 523**	40 610
Intersegment revenues	**3 124**	3 420	**529**	491	**212**	56	**(3 865)**	(3 967)	**—**	—
Less: Royalties	**(684)**	(799)	**(1 631)**	(1 472)	**—**	—	**—**	—	**(2 315)**	(2 271)
Operating revenues, net of royalties	**10 818**	11 204	**4 845**	5 312	**26 321**	25 713	**(3 776)**	(3 890)	**38 208**	38 339
Other income	**20**	31	**71**	(3)	**27**	58	**290**	367	**408**	453
	10 838	11 235	**4 916**	5 309	**26 348**	25 771	**(3 486)**	(3 523)	**38 616**	38 792
Expenses										
Purchases of crude oil and products	**211**	383	**444**	585	**20 395**	20 547	**(3 949)**	(3 790)	**17 101**	17 725
Operating, selling and general	**5 375**	5 169	**795**	850	**2 286**	2 182	**492**	223	**8 948**	8 424
Transportation	**337**	399	**182**	116	**204**	219	**(38)**	2	**685**	736
Depreciation, depletion, amortization and impairment	**3 964**	1 374	**1 857**	2 035	**468**	444	**161**	99	**6 450**	3 952
Exploration	**71**	56	**238**	60	**—**	—	**—**	—	**309**	116
(Gain) loss on disposal of assets	**(29)**	122	**(1)**	31	**(13)**	(16)	**(1)**	(1)	**(44)**	136
Project start-up costs	**57**	163	**—**	—	**3**	—	**—**	—	**60**	163
Financing expenses	**127**	74	**81**	65	**5**	13	**(147)**	319	**66**	471
	10 113	7 740	**3 596**	3 742	**23 348**	23 389	**(3 482)**	(3 148)	**33 575**	31 723
Earnings (Loss) Before Income Taxes	**725**	3 495	**1 320**	1 567	**3 000**	2 382	**(4)**	(375)	**5 041**	7 069
Income taxes										
Current	**1**	(3)	**1 154**	907	**342**	162	**18**	55	**1 515**	1 121
Deferred	**266**	895	**28**	354	**529**	494	**(80)**	(99)	**743**	1 644
	267	892	**1 182**	1 261	**871**	656	**(62)**	(44)	**2 258**	2 765
Net Earnings (Loss)	**458**	2 603	**138**	306	**2 129**	1 726	**58**	(331)	**2 783**	4 304
Capital and Exploration Expenditures	**4 957**	5 100	**1 261**	874	**646**	633	**95**	243	**6 959**	6 850

(1) During the first quarter of 2012, the company completed a review of the presentation of purchase and sale transactions in its Oil Sands segment. It was determined that certain transactions previously recorded on a gross basis are more appropriately reflected through net presentation as the substance of the arrangement is an exchange of similar crude inventory rather than a sale that generates revenue.

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

($ millions, decrease)	2011
Gross revenues	998
Purchase of crude oil and products	998
Net earnings	—

Geographical Information

Operating Revenues, net of Royalties ($ millions)	**2012**	2011
Canada	**30 175**	30 878
Foreign	**8 033**	7 461
	38 208	38 339

Non-Current Assets [2] ($ millions)	**Dec 31 2012**	Dec 31 2011
Canada	**55 766**	53 794
Foreign	**6 424**	6 799
	62 190	60 593

(2) Excludes deferred income tax assets.

7. OTHER INCOME

Other Income consists of the following:

($ millions)	**2012**	2011
Energy trading activities		
Change in fair value of contracts	**246**	301
Unrealized losses on inventory valuation	**(13)**	(19)
Risk management activities	**1**	(22)
Investment and interest income	**80**	141
Renewable energy grants	**59**	64
Other	**35**	(12)
	408	453

8. OPERATING, SELLING AND GENERAL

Operating, Selling and General expense consists of the following:

($ millions)	**2012**	2011
Contract services	**4 069**	4 107
Employee benefit costs [(1)]	**2 697**	2 062
Materials	**725**	882
Energy	**613**	712
Equipment rentals and leases	**330**	363
Travel, marketing and other	**514**	298
	8 948	8 424

(1) The company incurred $3.2 billion of employee benefit costs for the year ended December 31, 2012 (2011 – $2.5 billion), of which $2.7 billion (2011 – $2.1 billion) was recorded as employee benefits in Operating, Selling and General expense. Employee benefits expense includes salaries, benefits and share-based compensation.

9. ASSET IMPAIRMENT

Oil Sands

During the fourth quarter of 2012, the company recognized after-tax impairment charges of $1.487 billion related to the Voyageur upgrader project in its Oil Sands business. As a result of the challenging economic outlook for the Voyageur upgrader project, an impairment test was performed at December 31, 2012, using a fair value less cost to sell methodology. The company used an expected future cash flow approach, with a risk-adjusted discount rate of 10% to perform the calculation. As at December 31, 2012, the company's carrying value for assets relating to the Voyageur upgrader project was approximately $345 million.

The impairment charges were recorded as part of Depreciation, Depletion, Amortization and Impairment expense.

Syria

In December 2011, the company declared force majeure under its contractual obligations, suspended its operations and ceased recording production due to political unrest and international sanctions affecting that country. An impairment test was performed at that time, which determined that the assets were not impaired.

As there had been no resolution of the political situation at the end of the second quarter of 2012, another impairment test was performed on the company's Syrian assets. As a result, the company recognized after-tax impairment charges and write-downs of $694 million. The impairment losses were recorded as part of Depreciation, Depletion, Amortization and Impairment expense and charged against Property, Plant and Equipment ($604 million) and other current assets ($23 million). The company also wrote off the remainder of its Syrian receivables ($67 million). A write-down of receivables of $64 million was previously recorded at December 31, 2011.

During the fourth quarter of 2012, the company received $300 million of risk mitigation proceeds related to its Syrian operations. The proceeds are subject to a provisional repayment should the company resume operations in Syria and therefore, have been recorded as a non-current provision at December 31, 2012.

After receipt of the risk mitigation proceeds, an impairment test was performed at December 31, 2012, using a value-in-use methodology. The company used an expected cash flow approach based on 2011 year-end reserves data updated for the

company's best estimate of price realizations and remaining reserves, with three scenarios representing i) resumption of operations in one year, ii) resumption of operations in five years, and iii) total loss. The two scenarios where the company resumes operations incorporated repayment of the risk mitigation proceeds in accordance with the terms of the agreement. These scenarios were equally weighted based on the company's best estimates, and present valued using a risk-adjusted discount rate of 19%. Based on this assessment, the company recognized an impairment reversal of $177 million related to Syrian assets in its Exploration and Production business.

The impairment reversal of $177 million was recorded in the fourth quarter of 2012 as part of Depreciation, Depletion, Amortization and Impairment expense. A 2% change in discount rates and a 5% change in pricing assumptions would each have an impact on after-tax earnings of approximately $20 million.

The resulting carrying value of the company's Property, Plant, and Equipment in Syria, net of the risk mitigation provision, at December 31, 2012 was approximately $130 million.

Libya

In the second quarter of 2011, the company recognized after-tax impairment charges of $514 million related to Libyan assets in its Exploration and Production business. At that time, production had been shut in due to political violence in Libya. The impairment losses were recorded as part of Depreciation, Depletion, Amortization and Impairment expense, and charged against Property, Plant and Equipment ($259 million), Exploration and Evaluation assets ($211 million), and Inventories ($44 million).

During the fourth quarter of 2011, the company reversed $11 million of the impairment charge that related to crude oil inventories. The reversal was the result of lifting certain political sanctions, and the joint venture partner confirming the existence of previously written off crude oil.

Production payments resumed in January 2012 with production in all major fields restarted in the first quarter of 2012. As a result, a valuation assessment was performed. The company used an expected cash flow approach based on 2012 year-end reserves data with a risk-adjusted discount rate of 17% to reflect uncertainty related to continued political unrest in the region, current production levels and the timing and success of future exploration drilling commitments. No reversal of impairment was recorded at December 31, 2012. A 2% change in discount rates would impact after-tax earnings by approximately $90 million while a 5% change in pricing assumptions would impact after-tax earnings by approximately $70 million.

The carrying value of Suncor's net assets in Libya as at December 31, 2012, net of asset impairment and write-offs, was approximately $650 million.

Other

During the fourth quarter of 2012, the company recognized an after-tax impairment charge of $65 million related primarily to certain East Coast Canada exploration and evaluation assets as well as natural gas Arctic land leases in the Exploration and Production business as a result of future development uncertainty. In addition, the company also recognized an after-tax impairment charge of $63 million related to CGUs in the Exploration and Production business due to a decline in price forecasts. The recoverable amount was determined using a fair value less cost to sell methodology, with the expected cash flow approach based on 2012 year-end reserves data and a risk-adjusted discount rate of 10%. A 2% increase in discount rates would decrease after-tax earnings by approximately $90 million while a 5% decrease in pricing assumptions would decrease after-tax earnings by approximately $30 million.

During the fourth quarter of 2011, the company recognized a charge of $100 million to reflect the write-down of certain natural gas CGUs in the Exploration and Production business to reflect the recoverable amount based on discounted cash flows.

The impairment charges were recorded as part of Depreciation, Depletion, Amortization and Impairment expense.

10. FINANCING EXPENSES

($ millions)	**2012**	2011
Interest on debt	**643**	661
Capitalized interest at 6.0% (2011 – 6.0%)	**(587)**	(559)
Interest expense	**56**	102
Accretion	**182**	157
Foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(181)**	183
Foreign exchange and other	**9**	29
	66	471

11. INCOME TAXES

Income Tax Expense

($ millions)	**2012**	2011
Current:		
Current year	**1 483**	1 103
Adjustments for prior years	**32**	18
Deferred:		
Origination and reversal of temporary differences	**687**	1 258
Adjustments for prior years	**(32)**	(56)
Changes in tax rates and legislation	**88**	442
	2 258	2 765

There was no income tax recognized directly in equity during 2011 and 2012.

Reconciliation of Effective Tax Rate

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

($ millions)	**2012**	2011
Earnings before income tax	**5 041**	7 069
Canadian statutory tax rate	**25.67%**	27.19%
Statutory tax	**1 294**	1 922
Add (deduct) the tax effect of:		
Non-taxable component of capital gains and losses	**(22)**	(33)
Share-based compensation and other permanent items	**15**	34
Assessments and adjustments	**—**	(38)
Impact of income tax rate and legislative changes [(1)]	**88**	442
Canadian tax rate differential	**1**	(116)
Foreign tax rate differential	**763**	383
Non-taxable impairment charge	**127**	142
Other	**(8)**	29
	2 258	2 765

(1) In the second quarter of 2012, the Ontario government substantively enacted legislation to freeze the general corporate income tax rate at 11.5% instead of the planned reduction to 10%. Accordingly, the company recognized an increase in deferred tax expense of $88 million related to the revaluation of deferred income tax balances.

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

Deferred Income Tax Balances

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

	Consolidated Statements of Comprehensive Income		Consolidated Balance Sheets [1]	
($ millions)	**2012**	2011	**Dec 31 2012**	Dec 31 2011
Property, plant and equipment	**1 266**	967	**11 991**	10 725
Decommissioning and restoration provision	**(625)**	205	**(1 132)**	(507)
Employee retirement benefit plans	**(55)**	73	**(636)**	(518)
Tax loss carry-forwards	**391**	(213)	**(167)**	(558)
Partnership deferral reserve	**(189)**	594	**405**	594
Other	**(45)**	18	**(78)**	(77)
	743	1 644	**10 383**	9 659

(1) The deferred income tax liability of $10.463 billion at December 31, 2012 (December 31, 2011 – $9.719 billion) includes $10.322 billion (December 31, 2011 – $9.713 billion) that will be settled beyond the next twelve months.

The deferred income tax asset of $80 million at December 31, 2012 (December 31, 2011 – $60 million) includes $71 million (December 31, 2011 – $47 million) that will be recovered beyond the next twelve months.

Change in Deferred Income Tax Balances

($ millions)	**2012**	2011
Beginning of year	**9 659**	7 842
Recognized in deferred income tax expense	**743**	1 644
Recognized in other comprehensive income	**(63)**	(117)
Foreign exchange and other	**44**	290
End of year	**10 383**	9 659

No deferred tax liability has been recognized at December 31, 2012 on temporary differences of approximately $10 billion (2011 – $9 billion) associated with earnings retained in our investments in foreign subsidiaries, as the company is able to control the timing of the reversal of these differences. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional income tax expense. Deferred distribution taxes associated with international business operations have not been recorded.

In January 2013, the company received a proposal letter from the Canada Revenue Agency (CRA) relating to the income tax treatment of the realized losses in 2007 on the settlement of the 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 that 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 approximately 50% of the amount payable under the NOR, currently estimated to be $600 million, which would remain on account until the dispute is resolved.

12. EARNINGS PER COMMON SHARE

($ millions)	**2012**	2011
Net earnings	**2 783**	4 304
Dilutive impact of accounting for awards as equity-settled [1]	**(7)**	(86)
Net earnings – diluted	**2 776**	4 218
(millions of common shares)		
Weighted-average number of common shares	**1 545**	1 571
Dilutive securities:		
Effect of share options	**4**	11
Weighted-average number of diluted common shares	**1 549**	1 582
(dollars per common share)		
Basic earnings per share	**1.80**	2.74
Diluted earnings per share	**1.79**	2.67

(1) Options with tandem stock appreciation rights or cash payment alternatives are accounted for as cash-settled plans. As these awards can be exchanged for common shares of the company, they are considered potentially dilutive and are included in the calculation of the company's diluted net earnings per share calculation if they have a dilutive impact in the period. Accounting for these awards as equity-settled was determined to have a dilutive impact for the years ended December 31, 2012 and 2011.

13. CASH AND CASH EQUIVALENTS

($ millions)	**Dec 31 2012**	Dec 31 2011
Cash	**636**	832
Cash equivalents	**3 757**	2 971
	4 393	3 803

14. SUPPLEMENTAL CASH FLOW INFORMATION

The (increase) decrease in non-cash working capital is comprised of:

($ millions)	**2012**	2011
Accounts receivable	**186**	(263)
Inventories	**451**	(1 064)
Accounts payable and accrued liabilities	**(1 738)**	1 322
Provisions	**45**	203
Income taxes payable/receivable	**106**	70
	(950)	268
Relating to:		
Operating activities	**(899)**	242
Investing activities	**(51)**	26

15. INVENTORIES

($ millions)	**Dec 31 2012**	Dec 31 2011
Crude oil	**1 091**	1 321
Refined products	**1 569**	1 741
Materials, supplies and merchandise	**597**	592
Energy trading commodity inventories	**486**	551
	3 743	4 205

During 2012, product inventories of $17.7 billion (2011 – $18.7 billion) were expensed. There was a write-down of inventories of $45 million in 2012 (2011 – $33 million).

16. PROPERTY, PLANT AND EQUIPMENT

($ millions)	Oil and Gas Properties	Plant and Equipment	Total
Cost			
At December 31, 2010	16 981	42 717	59 698
Additions	1 358	4 952	6 310
Transfers from exploration and evaluation	237	—	237
Acquisitions (note 31)	—	126	126
Changes in decommissioning and restoration	1 862	15	1 877
Disposals	(405)	(2 717)	(3 122)
Foreign exchange adjustments	256	50	306
At December 31, 2011	20 289	45 143	65 432
Additions	**1 739**	**4 955**	**6 694**
Transfers from exploration and evaluation	**1 598**	**—**	**1 598**
Changes in decommissioning and restoration	**899**	**92**	**991**
Disposals	**(49)**	**(185)**	**(234)**
Foreign exchange adjustments	**(22)**	**(55)**	**(77)**
At December 31, 2012	**24 454**	**49 950**	**74 404**
Accumulated provision			
At December 31, 2010	(3 028)	(6 712)	(9 740)
Depreciation and depletion	(1 622)	(1 770)	(3 392)
Impairment (note 9)	(359)	—	(359)
Disposals	316	356	672
Foreign exchange adjustments	(13)	(11)	(24)
At December 31, 2011	(4 706)	(8 137)	(12 843)
Depreciation and depletion	**(1 634)**	**(2 060)**	**(3 694)**
Impairment (note 9)	**(204)**	**(2 484)**	**(2 688)**
Impairment reversal (note 9)	**34**	**143**	**177**
Disposals	**42**	**57**	**99**
Foreign exchange adjustments	**(25)**	**28**	**3**
At December 31, 2012	**(6 493)**	**(12 453)**	**(18 946)**
Net property, plant and equipment			
December 31, 2011	15 583	37 006	52 589
December 31, 2012	**17 961**	**37 497**	**55 458**

	Dec 31, 2012			Dec 31, 2011		
($ millions)	**Cost**	**Accumulated provision**	**Net book value**	Cost	Accumulated provision	Net book value
Oil Sands	**47 337**	**(10 440)**	**36 897**	41 679	(6 548)	35 131
Exploration and Production	**16 335**	**(5 691)**	**10 644**	13 757	(4 018)	9 739
Refining and Marketing	**9 498**	**(2 367)**	**7 131**	8 834	(1 953)	6 881
Corporate, Energy Trading and Eliminations	**1 234**	**(448)**	**786**	1 162	(324)	838
	74 404	**(18 946)**	**55 458**	65 432	(12 843)	52 589

At December 31, 2012, the balance of assets under construction, and not subject to depreciation or depletion, was $12.2 billion (December 31, 2011 – $16.2 billion).

At December 31, 2012, Property, Plant and Equipment included finance leases with a net book value of $831 million (December 31, 2011 – $425 million).

17. EXPLORATION AND EVALUATION ASSETS

($ millions)	**2012**	2011
Beginning of year	**4 554**	3 961
Acquisitions	**—**	716
Additions	**478**	657
Transfers to oil and gas assets	**(1 598)**	(237)
Dry hole expenses	**(145)**	(21)
Disposals	**—**	(263)
Impairment (note 9)	**(88)**	(211)
Amortization	**(24)**	(44)
Foreign exchange adjustments	**107**	(4)
End of year	**3 284**	4 554

18. OTHER ASSETS

($ millions)	**Dec 31 2012**	Dec 31 2011
Investments	**247**	228
Other	**73**	83
	320	311

19. GOODWILL AND OTHER INTANGIBLE ASSETS

	Oil Sands	Refining and Marketing			
($ millions)	Goodwill	Goodwill	Brand name	Customer lists	Total
At December 31, 2010	3 019	182	166	55	3 422
Derecognition of goodwill (note 31)	(267)	(8)	—	—	(275)
Additions	—	—	—	3	3
Amortization	—	—	—	(11)	(11)
At December 31, 2011	2 752	174	166	47	3 139
Derecognition of goodwill	**—**	**(2)**	**—**	**—**	**(2)**
Additions	**—**	**—**	**—**	**5**	**5**
Amortization	**—**	**—**	**—**	**(14)**	**(14)**
At December 31, 2012	**2 752**	**172**	**166**	**38**	**3 128**

The company performed its most recent goodwill impairment test at July 31, 2012. Recoverable amounts for the Oil Sands CGUs were based on fair value less costs to sell calculated using the present value of the CGUs' expected future cash flows. The primary sources of cash flow information are derived from business plans approved by executives of the company, which were developed based on macroeconomic factors such as forward price curves for benchmark commodities, inflation rates and industry supply-demand fundamentals. When required, the projected cash flows in the business plan have been updated to reflect current market assessments of key assumptions, including long-term forecasts of commodity prices, inflation rates, foreign exchange rates and discount rates specific to the asset.

Cash flow forecasts are also based on past experience, historical trends and third-party evaluations of the company's reserves and resources to determine production profiles and volumes, operating costs, maintenance and capital expenditures. Production profiles, reserves volumes, operating costs, maintenance and capital expenditures are consistent with the estimates approved through the company's annual reserves evaluation process and determine the duration of the underlying cash flows used in the discounted cash flow test.

Future cash flow estimates are adjusted to reflect risks specific to the asset and discounted using after-tax discount rates. The discount rate is calculated based on the weighted-average cost of capital that is implicit in current market transactions for similar assets. The after-tax discount rate applied to cash flow projections was 10% at July 31, 2012 (July 31, 2011 – 11%) with a growth rate equal to the current inflation rate of 2% (July 31, 2011 – 2%). As a result of this analysis, management did not identify impairment within the Oil Sands operating segment and the associated allocated goodwill.

The company also performed a goodwill impairment test at July 31, 2012 of its Refining and Marketing operating segment, and no impairment was identified within the operating segment and the associated allocated goodwill.

20. DEBT AND CREDIT FACILITIES

Debt and credit facilities are comprised of the following:

Short-Term Debt

($ millions)	**Dec 31 2012**	Dec 31 2011
Commercial paper [1]	**775**	761
Other	**1**	2
Total short-term debt	**776**	763

(1) The commercial paper is supported by a revolving credit facility with a separate lender. The company is authorized to issue commercial paper to a maximum of $2.5 billion having a term not to exceed 365 days. The weighted-average interest rate as at December 31, 2012 was 0.4% (December 31, 2011 – 0.4%)

Long-Term Debt

($ millions)	**Dec 31 2012**	Dec 31 2011
Fixed-term debt, redeemable at the option of the company		
6.85% Notes, due 2039 (US$750)	**746**	763
6.80% Notes, due 2038 (US$900)	**921**	942
6.50% Notes, due 2038 (US$1150)	**1 144**	1 170
5.95% Notes, due 2035 (US$600)	**556**	566
5.95% Notes, due 2034 (US$500)	**498**	509
5.35% Notes, due 2033 (US$300)	**259**	263
7.15% Notes, due 2032 (US$500)	**498**	509
6.10% Notes, due 2018 (US$1250)	**1 244**	1 271
6.05% Notes, due 2018 (US$600)	**606**	621
5.00% Notes, due 2014 (US$400)	**402**	413
4.00% Notes, due 2013 (US$300)	**299**	305
7.00% Debentures, due 2028 (US$250)	**256**	263
7.875% Debentures, due 2026 (US$275)	**303**	312
9.25% Debentures, due 2021 (US$300)	**361**	376
5.39% Series 4 Medium Term Notes, due 2037	**600**	600
5.80% Series 4 Medium Term Notes, due 2018	**700**	700
Total unsecured long-term debt	**9 393**	9 583
Secured long-term debt	**13**	13
Finance leases [2]	**894**	476
Deferred financing costs	**(51)**	(56)
	10 249	10 016
Current portion of long-term debt		
Finance leases	**(12)**	(12)
4.00% Notes, due July 2013 (US$300)	**(299)**	—
	(311)	(12)
Total long-term debt	**9 938**	10 004

(2) Interest rates range from 4.6% to 13.4% and maturity dates range from 2017 to 2037.

Scheduled Debt Repayments

Scheduled principle repayments for finance leases, short-term debt and long-term debt are as follows:

($ millions)	Repayment
2013	1 087
2014	427
2015	18
2016	19
2017	19
Thereafter	9 447
	11 017

Credit Facilities

A summary of available and unutilized credit facilities is as follows:

($ millions)	**2012**
Fully revolving for a period of one year after term-out date (November 2013)	**2 000**
Fully revolving and expires in 2013-2014	**924**
Fully revolving for a period of four years and expires in 2016	**3 000**
Can be terminated at any time at the option of the lenders	**379**
Total credit facilities	**6 303**
Credit facilities supporting outstanding commercial paper	**(775)**
Credit facilities supporting standby letters of credit [3]	**(793)**
Total unutilized credit facilities	**4 735**

(3) The company secures certain obligations and commitments with letters of credit, of which $150 million is pledged with cash as at December 31, 2012.

21. OTHER LONG-TERM LIABILITIES

($ millions)	**Dec 31 2012**	Dec 31 2011
Pensions and other post-retirement benefits (note 22)	**1 634**	1 683
Share-based compensation plans (note 25)	**242**	187
Deferred revenue	**77**	84
Fort Hills purchase obligation [1]	**223**	275
Libya EPSAs signature bonus [2]	**72**	73
Other	**62**	90
	2 310	2 392

(1) As part of the 2009 acquisition of Petro-Canada, the company assumed an obligation relating to Petro-Canada's acquisition of an additional 5% interest in the Fort Hills project. To pay for this investment, the company will fund $375 million of expenditures in excess of its working interest. At December 31, 2012, the carrying amount of the Fort Hills obligation, based on the discounted estimated payout pattern for the funding, was $300 million (2011 – $327 million), of which the current portion is $77 million (2011 – $52 million) and is recorded in Accounts Payable and Accrued Liabilities.

(2) The company also assumed the remaining US$500 million obligation for a signature bonus relating to Petro-Canada's ratification of six Exploration and Production Sharing Agreements (EPSAs) in Libya payable in several instalments through 2013. The company also has a US$47 million obligation related to merger consent. At December 31, 2012, the carrying amount of the total Libya obligation was $86 million (2011– $342 million), of which the current portion is $14 million (2011 – $269 million) and is recorded in Accounts Payable and Accrued Liabilities.

22. PENSIONS AND OTHER POST-RETIREMENT BENEFITS

The company's defined benefit pension plans provide pension benefits at retirement based on years of service and final average earnings (if applicable). These obligations are met through funded registered retirement plans and through unregistered supplementary pensions that are voluntarily funded through retirement compensation arrangements, and/or paid directly to recipients. The amount and timing of future funding for these supplementary plans is subject to the funding policy as approved by the Board of Directors. The company's contributions to the funded plans are deposited with independent trustees who act as

custodians of the plans' assets, as well as the disbursing agents of the benefits to recipients. Plan assets are managed by a pension committee on behalf of beneficiaries. The committee retains independent managers and advisors.

Funding of the registered retirement plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status, and every year in the United States. The most recent valuations were performed as at December 31, 2012. The company uses a measurement date of December 31 to value the plan assets and accrued benefit obligation for accounting purposes.

The company's other post-retirement benefits programs are unfunded and include certain health care and life insurance benefits provided to retired employees and eligible surviving dependants.

The company also provides a number of defined contribution plans, including a U.S. 401(k) savings plan, that provide for an annual contribution of 5% to 11.5% of each participating employee's pensionable earnings.

Defined Benefit Obligations and Funded Status

	Pension Benefits		Other Post-Retirement Benefits	
($ millions)	**2012**	2011	**2012**	2011
Change in benefit obligation				
Benefit obligation at beginning of year	**3 698**	3 219	**510**	462
Current service costs	**143**	111	**11**	10
Plan participants' contributions	**14**	13	**—**	—
Benefits paid	**(172)**	(161)	**(18)**	(17)
Interest costs	**163**	165	**22**	23
Foreign exchange	**2**	(18)	**—**	—
Settlements	**2**	(6)	**—**	—
Actuarial loss	**287**	375	**20**	32
Benefit obligation at end of year	**4 137**	3 698	**545**	510
Change in plan assets				
Fair value of plan assets at beginning of year	**2 499**	2 335	**—**	—
Employer contributions	**267**	205	**—**	—
Plan participants' contributions	**14**	13	**—**	—
Benefits paid	**(172)**	(161)	**—**	—
Foreign exchange	**2**	3	**—**	—
Settlements	**2**	(7)	**—**	—
Expected return on plan assets	**164**	160	**—**	—
Actuarial gain (loss)	**67**	(49)	**—**	—
Fair value of plan assets at end of year	**2 843**	2 499	**—**	—
Net unfunded obligation	**1 294**	1 199	**545**	510

The net unfunded obligation is recorded in Accounts Payable and Accrued Liabilities and Other Long-Term Liabilities (note 21) in the Consolidated Balance Sheets.

	Pension Benefits		Other Post-Retirement Benefits	
($ millions)	**2012**	2011	**2012**	2011
Analysis of amount charged to earnings:				
Current service costs	**143**	111	**11**	10
Interest costs	**163**	165	**22**	23
Settlement	**—**	1	**—**	—
Expected return on plan assets	**(164)**	(160)	**—**	—
Defined benefit plans expense	**142**	117	**33**	33
Defined contribution plans expense	**53**	43	**—**	—
Total benefit plans expense charged to earnings	**195**	160	**33**	33

History of surplus and deficit and of experience gains and losses were as follows:

($ millions)	Pension Benefits			Other Post-Retirement Benefits		
	2012	2011	2010	**2012**	2011	2010
Benefit obligation at December 31	**4 137**	3 698	3 219	**545**	510	462
Less: Fair value of plan assets at December 31	**2 843**	2 499	2 335	**—**	—	—
Net unfunded obligation	**1 294**	1 199	884	**545**	510	462
Actuarial (gain) loss on plan assets	**(67)**	49	(82)	**—**	—	—
Change in assumptions underlying the present value of the plan liabilities	**269**	367	240	**33**	35	45
Experience (gains) and losses arising on the plan liabilities	**18**	8	3	**(13)**	(3)	(5)
Actuarial loss recognized in other comprehensive income	**220**	424	161	**20**	32	40
Cumulative amount recognized in other comprehensive income	**805**	585	161	**92**	72	40

Actuarial Assumptions

The cost of the defined benefit pension plans and other post-retirement benefits received by employees is actuarially determined using the projected unit credit method of valuation that includes employee service to date and present pay levels, as well as projection of salaries and service to retirement.

The significant weighted-average actuarial assumptions were as follows:

(%)	Pension Benefits		Other Post-Retirement Benefits	
	2012	2011	**2012**	2011
Benefit Obligation at December 31				
Discount rate	**3.90**	4.40	**3.90**	4.40
Rate of compensation increase	**3.65**	3.70	**3.75**	3.70
Benefit Plans Expense year ended December 31				
Discount rate	**4.40**	5.10	**4.40**	5.25
Expected return on plan assets	**6.45**	6.70	**N/A**	N/A
Rate of compensation increase	**3.65**	3.70	**3.75**	4.00

The discount rate assumption is based on the interest rate on high-quality bonds with maturity terms equivalent to the benefit obligations.

The expected return on plan assets is the expected long-term rate of return on plan assets for the year and is based on plan assets at the beginning of the year that have been adjusted on a weighted-average basis for contributions and benefit payments expected for the year.

To estimate the expected long-term rate of return on plan assets, the company considered the current level of expected returns on the fixed income portion of the portfolio, the historical level of the risk premium associated with other asset classes in which the portfolio is invested and the expectation for future returns on each asset class. The expected return for each asset class was weighted based on the policy asset mix to develop an expected long-term rate of return on asset assumption for the portfolio.

In order to measure the expected cost of other post-retirement benefits, a 7% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2012 (2011 – 7%). It is assumed this rate will remain constant in 2013 and 2014 and will decrease 0.5% annually to 5% by 2018, and remain at that level thereafter.

Assumed discount rates and health care cost trend rates may have a significant effect on the amounts reported for pensions and other post-retirement benefit obligations. A 1% change of these assumed assumptions would have the following effects:

($ millions)	Pension Benefits Increase	Pension Benefits Decrease
Discount rate		
Effect on the aggregate service and interest costs	(16)	16
Effect on the benefit obligations	(460)	559

($ millions)	Other Post-Retirement Benefits Increase	Other Post-Retirement Benefits Decrease
Discount rate		
Effect on the aggregate service and interest costs	(1)	1
Effect on the benefit obligations	(66)	83
Health care cost		
Effect on the aggregate service and interest costs	2	(2)
Effect on the benefit obligations	49	(41)

Plan Assets and Investment Objectives

The company's long-term investment objective is to secure the defined pension benefits while managing the variability and level of its contributions. The portfolio is rebalanced periodically, as required, while ensuring that the maximum equity content is 65% at any time. Plan assets are restricted to those permitted by legislation, where applicable. Investments are made through pooled, mutual, segregated or exchange traded funds.

The company's weighted-average pension plan asset allocation based on market values as at December 31, are as follows:

(%)	**2012**	2011
Equities	**58**	55
Fixed income	**42**	45
Total	**100**	100

Equity securities do not include any direct investments in Suncor shares.

The company expects to make cash contributions to its defined benefit pension plans in 2013 of $276 million.

23. PROVISIONS

($ millions)	Decommissioning and Restoration [1]	Royalties [2]	Other	Total
At December 31, 2010	2 633	370	420	3 423
Liabilities incurred	219	237	42	498
Changes in estimates	1 690	4	1	1 695
Liabilities settled	(496)	(256)	(63)	(815)
Accretion	140	—	6	146
Asset divestitures	(390)	—	—	(390)
Foreign exchange	5	—	1	6
At December 31, 2011	3 801	355	407	4 563
Less: current portion	(372)	(355)	(84)	(811)
	3 429	—	323	3 752
At December 31, 2011	3 801	355	407	4 563
Liabilities incurred	**378**	**317**	**408**	**1 103**
Changes in estimates	**783**	**51**	**(14)**	**820**
Liabilities settled	**(433)**	**(356)**	**(73)**	**(862)**
Accretion	**163**	**—**	**6**	**169**
Foreign exchange	**(4)**	**—**	**—**	**(4)**
At December 31, 2012	**4 688**	**367**	**734**	**5 789**
Less: current portion	**(395)**	**(367)**	**(94)**	**(856)**
	4 293	**—**	**640**	**4 933**

(1) Represents decommissioning and restoration provisions associated with the retirement of Property, Plant and Equipment and Exploration and Evaluation assets. The total undiscounted amount of estimated future cash flows required to settle the obligations at December 31, 2012 was approximately $8.1 billion (December 31, 2011 – $7.3 billion). A weighted-average credit-adjusted risk-free interest rate of 3.75% was used to discount the provision recognized at December 31, 2012 (December 31, 2011 – 4.3%). The credit-adjusted risk-free rate used reflects the expected timeframe of the provisions. Payments to settle the decommissioning and restoration provisions occur on an ongoing basis and will continue over the lives of the operating assets, which can exceed fifty years.

(2) In 2010, the Minister of Energy for the Province of Alberta provided notice to the company for the quality and transportation adjustments to be used under the Bitumen Valuation Methodology (BVM) Regulations for the term of the Suncor Royalty Amending Agreement that expires December 31, 2015. In the fourth quarter of 2012, the company agreed to remit $328 million, under protest, related to 2011 and 2012. The company continues to pursue final settlement of the quality adjustment.

24. SHARE CAPITAL

Authorized

Common Shares

The company is authorized to issue an unlimited number of common shares without nominal or par value.

Preferred Shares

The company is authorized to issue an unlimited number of preferred shares in series, without nominal or par value.

Normal Course Issuer Bid

In September 2012, the company completed its first Normal Course Issuer Bid and put option program, and also announced a second Normal Course Issuer Bid program to purchase for cancellation up to $1 billion of its common shares between September 20, 2012 and September 19, 2013.

During the twelve months ended December 31, 2012, the company purchased 46.9 million (2011 – 17.1 million) common shares for total consideration of $1,451 million (2011 – $500 million), net of $1.3 million (2011 – $nil) option premiums recognized in share capital. Of the amount recognized, $609 million (2011 – $222 million) was charged to share capital and $842 million (2011 – $278 million) to retained earnings.

The company has also recorded a liability of $48 million for share purchases that may take place during its internal blackout period under an automatic repurchase plan agreement with an independent broker. Of the liability recognized, $19 million was charged to share capital and $29 million to retained earnings.

25. SHARE-BASED COMPENSATION

(a) Stock Option Plans

Stock options that give the holder the right to purchase common shares at the grant date market price subject to fulfilling vesting terms are accounted for as equity-settled plans. Stock options that the holder can settle for cash or common shares are accounted for as cash-settled plans.

Equity-Settled Stock Option Plans

(i) Suncor Energy Inc. Stock Options

This plan replaced the pre-merger stock option plans of legacy Suncor and legacy Petro-Canada. Outstanding options that are cancelled, expire or otherwise result in no underlying common share being issued, will be available for issuance as options under this plan. Options granted have a seven-year life and vest annually over a three-year period.

(ii) Discontinued Plans

The following plans were in place prior to August 1, 2009: SunShare 2012 Performance Stock Options, Executive Stock Options, Key Contributor Stock Options, and legacy Petro-Canada Stock Options. For options granted under these plans, they generally have a seven to ten-year life and vest over periods up to four years. As of January 1, 2013 the SunShare 2012 Performance Stock Option plan will be fully vested. All outstanding unvested options at January 1, 2013 will automatically expire.

The weighted-average fair values of the options granted during the period and the weighted-average assumptions used in their determination are as noted below:

	2012	2011
Annual dividend per share	**$0.50**	$0.43
Risk-free interest rate	**1.91%**	2.50%
Expected life	**5 years**	5 years
Expected volatility	**50%**	49%
Weighted-average fair value per option	**$15.01**	$16.52

The expected life is based on historical experience and current expectations. The expected volatility reflects the assumption that the historical volatility over a period similar to the life of the options is indicative of future trends.

Cash-Settled Stock Option Plans

(i) Suncor Energy Inc. Stock Options with TSARs

Options were granted under this plan between August 1, 2009 and July 31, 2010. Each option included a tandem stock appreciation right (TSAR). Options granted have a seven-year life and vest annually over a three-year period.

(ii) Legacy Petro-Canada Stock Options with CPAs

This plan was discontinued on August 1, 2009. Options were granted to executives and key employees, and can be settled in common shares or exchanged for a cash payment alternative (CPA). Options granted have a seven-year life and vest over periods of up to four years.

Changes in the total outstanding stock options were as follows:

	2012		2011	
	Number (thousands)	**Weighted-Average Exercise Price ($)**	Number (thousands)	Weighted-Average Exercise Price ($)
Outstanding, beginning of year	**59 178**	**35.25**	67 638	32.94
Granted	**5 101**	**34.50**	5 840	41.08
Exercised	**(10 803)**	**17.31**	(9 918)	20.93
Forfeited/expired	**(6 152)**	**42.08**	(4 382)	40.51
Outstanding, end of year	**47 324**	**38.33**	59 178	35.25
Exercisable, end of year	**29 834**	**36.23**	39 482	32.03

Options are exercised regularly throughout the year. Therefore, the weighted-average share price during the year of $31.94 (2011 – $36.18) is representative of the weighted-average share price at the date of exercise.

For the options outstanding at December 31, 2012, the exercise price ranges and weighted-average remaining contractual lives are shown below:

	Outstanding	
Exercise Prices ($)	Number (thousands)	Weighted-Average Remaining Contractual Life (years)
11.99-19.99	3 592	2
20.00-29.99	3 494	2
30.00-39.99	14 184	4
40.00-49.99	25 015	3
50.00-69.97	1 039	2
Total	47 324	3

Common shares authorized for issuance by the Board of Directors that remain available for the granting of future options:

(thousands)	**Dec 31 2012**	Dec 31 2011
	7 020	10 347

(b) Stock Appreciation Rights (SARs)

A SAR entitles the holder to receive a cash payment equal to the difference between the stated exercise price and the market price of the company's common shares on the date the SAR is exercised, and is accounted for as a cash-settled plan.

(i) Suncor Energy Inc. SARs

These SARs have a seven-year life and vest annually over a three-year period.

(ii) Legacy Petro-Canada SARs

This plan was discontinued on August 1, 2009. These SARs have a seven-year life and vest annually over a four-year period.

Changes in the number of outstanding SARs were as follows:

	2012		2011	
	Number (thousands)	**Weighted-Average Exercise Price ($)**	Number (thousands)	Weighted-Average Exercise Price ($)
Outstanding, beginning of year	**8 752**	**29.32**	11 285	28.97
Granted	**101**	**34.51**	197	41.26
Exercised	**(482)**	**20.53**	(2 003)	29.54
Forfeited/expired	**(595)**	**32.86**	(727)	28.10
Outstanding, end of year	**7 776**	**29.65**	8 752	29.32
Exercisable, end of year	**6 568**	**30.80**	5 625	31.49

(c) Share Unit Plans

The company's share unit plans are accounted for as cash-settled plans.

A performance share unit (PSU) is a time-vested award entitling employees to receive varying degrees of cash (0% – 200% of the company's share price at time of vesting) contingent upon Suncor's total shareholder return (stock price appreciation and dividend income) relative to a peer group of companies. PSUs vest approximately three years after the grant date.

A restricted share unit (RSU) is a time-vested award entitling employees to receive cash equal to the company's share price at the time of vesting. Typically, RSUs vest approximately three years after the grant date.

A deferred share unit (DSU) is redeemable for cash or a common share for a period of time after a unitholder ceases employment or Board membership. The DSU plan is limited to executives and members of the Board of Directors. Members of

the Board of Directors receive one-half or, at their option, all of their compensation in the form of DSUs. Executives may elect to receive one-half, or all, of their annual incentive payment in the form of DSUs.

Changes in the number of outstanding share units were as follows:

(thousands)	PSU	RSU	DSU
Outstanding, December 31, 2010	3 747	6 450	2 299
Granted	2 050	4 237	152
Redeemed for cash	(224)	(840)	(749)
Forfeited/expired	(913)	(553)	—
Outstanding, December 31, 2011	4 660	9 294	1 702
Granted	**1 021**	**6 803**	**198**
Redeemed for cash	**(1 168)**	**(2 666)**	**(263)**
Forfeited/expired	**(135)**	**(566)**	**—**
Outstanding, December 31, 2012	**4 378**	**12 865**	**1 637**

Share-Based Compensation Expense (Recovery)

The following table summarizes the share-based compensation expense (recovery) recorded for all plans within Operating, Selling and General expense in the Consolidated Statements of Comprehensive Income.

($ millions)	**2012**	2011
Equity-settled plans	**83**	94
Cash-settled plans	**269**	(95)
Total share-based compensation expense (recovery)	**352**	(1)

Liability Recognized for Share-Based Compensation

The company has recorded a liability of $523 million as at December 31, 2012 (December 31, 2011 – $405 million), of which $281 million was classified as current (December 31, 2011 – $218 million), based on the fair value of awards accounted for as cash-settled. The intrinsic value of the vested awards at December 31, 2012 was $237 million (December 31, 2011 – $161 million).

26. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The company's financial instruments consist of cash and cash equivalents, accounts receivable, derivative contracts, substantially all accounts payable and accrued liabilities, debt, and certain portions of other assets and other long-term liabilities.

Non-Derivative Financial Instruments

The fair values of cash and cash equivalents, accounts receivable, short-term debt, and accounts payable and accrued liabilities approximate their carrying values due to the short-term maturities of those instruments.

The fair value of the company's financial instrument included in other assets was calculated using a discounted cash flow model. The inputs used in the model were based on observable market data, where available.

The company's long-term debt and long-term financial liabilities are recorded at amortized cost using the effective interest method. At December 31, 2012, the carrying value of fixed-term debt accounted for under amortized cost was $9.4 billion (December 31, 2011 – $9.6 billion) and the fair value at December 31, 2012 was $11.8 billion (December 31, 2011 – $11.4 billion). The estimated fair value of long-term debt is based on pricing sourced from market data.

Derivative Financial Instruments

(a) Non-Designated Derivative Financial Instruments

Energy Trading Derivatives

The company's Energy Trading group also uses physical and financial energy contracts, including swaps, forwards and options to earn trading revenues.

Gains or losses from trading activities are reported in Other Income as part of Corporate, Energy Trading and Eliminations. The earnings impact for the year ended December 31, 2012 was a gain of $246 million (2011 – gain of $301 million).

Risk Management Derivatives

The company periodically enters into derivative contracts which although not accounted for as hedges because they have not been documented as such, or do not qualify under IFRS, are believed to be economically effective at managing exposure to commodity price and foreign exchange movements and are a component of the company's overall risk management program.

Gains or losses associated with risk management derivatives are reported in the related operating segment as part of Other Income. The earnings impact associated with these contracts for the year ended December 31, 2012 was a gain of $1 million (2011 – loss of $22 million).

Change in Fair Value of Non-Designated Derivative Financial Instruments

($ millions)	Risk Management	Energy Trading	Total
Fair value of contracts outstanding at January 1, 2011	13	(87)	(74)
Fair value of contracts realized during the period	9	(248)	(239)
Changes in fair value during the period	(22)	301	279
Fair value of contracts outstanding at December 31, 2011	—	(34)	(34)
Fair value of contracts realized during the period	**(2)**	**(255)**	**(257)**
Changes in fair value during the period	**1**	**246**	**247**
Fair value of contracts outstanding at December 31, 2012	**(1)**	**(43)**	**(44)**

(b) Fair Value Hierarchy

To estimate fair value of derivatives, the company uses quoted market prices when available, or third-party models and valuation methodologies that utilize observable market data. In addition to market information, the company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction. The company characterizes inputs used in determining fair value using a hierarchy that prioritizes inputs depending on the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

- Level 1 – inputs represent quoted prices in active markets for identical assets or liabilities. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – inputs other than quoted prices that are observable, either directly or indirectly, as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, market interest rates, and volatility factors, which can be observed or corroborated in the marketplace.
- Level 3 – inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value.

In forming estimates, the company utilizes the most observable inputs available for valuation purposes. If a fair value measurement reflects inputs of different levels within the hierarchy, the measurement is categorized based upon the lowest level of input that is significant to the fair value measurement.

The following table presents the company's derivative financial instrument assets and liabilities measured at fair value for each hierarchy level as at December 31, 2012 and 2011:

($ millions)	Level 1	Level 2	Level 3	Total Fair Value
Accounts receivable	1	33	3	37
Accounts payable	(18)	(51)	(2)	(71)
Balance at December 31, 2011	(17)	(18)	1	(34)
Accounts receivable	**5**	**47**	**1**	**53**
Accounts payable	**(12)**	**(85)**	**—**	**(97)**
Balance at December 31, 2012	**(7)**	**(38)**	**1**	**(44)**

Risk Management

The company is exposed to a number of different risks arising from financial instruments. These risk factors include market risks, comprising commodity price risk, foreign currency risk and interest rate risk, as well as liquidity risk and credit risk.

The company maintains a formal governance process to manage its financial risks. The company's Commodity Risk Management Committee (CRMC) is charged with the oversight of the company's trading and credit risk management activities. Trading activities are defined as activities intended to enhance the company's operations and enhance profitability through informed market calls, market diversification, economies of scale, improved transportation access, and leverage of assets, both physical and contractual. Trading activities also include strategic and operational hedging. The CRMC, acting under the authority of the company's Board of Directors, meets regularly to monitor limits on risk exposures, review policy compliance and validate risk-related methodologies and procedures.

The nature of the risks faced by the company and its policies for managing such risks remains unchanged from December 31, 2011.

1) Market Risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of the business. The market price movements that could adversely affect the value of the company's financial assets, liabilities and expected future cash flows include commodity price risk, foreign currency exchange risk and interest rate risk.

(a) Commodity Price Risk

Suncor's financial performance is closely linked to crude oil prices (including pricing differentials for various product types), and to a lesser extent, natural gas and refined product prices. The company may reduce its exposure to commodity price risk through a number of strategies. These strategies include committing a portion of expected crude oil production to fixed price contracts, entering into option contracts to limit exposure to changes in crude oil prices and hedging natural gas exposures to manage regional price differentials.

An increase of US$1.00/barrel of crude oil and US$0.10/mcf of natural gas prices as at December 31, 2012 would decrease pre-tax earnings by approximately $9 million and $2 million, respectively.

(b) Foreign Currency Exchange Risk

The company is exposed to foreign currency exchange risk on revenues, capital expenditures, or financial instruments that are denominated in a currency other than the company's functional currency (Canadian dollars). As crude oil is priced in U.S. dollars, fluctuations in US$/Cdn$ exchange rates may have a significant impact on revenues. This exposure is partially offset through the issuance of U.S. dollar denominated long-term debt and by sourcing capital projects in U.S. dollars. A 1% strengthening in the Cdn$ relative to the US$ as at December 31, 2012 would decrease pre-tax earnings by approximately $86 million.

The company also has foreign operations whose functional currency is different than the company's functional currency. The main exposures relate to foreign operations whose functional currencies are in U.S. dollars or Euros (€). A 1% strengthening in the Cdn$ relative to the US$ and € as at December 31, 2012 would decrease Other Comprehensive Income by approximately $46 million and $26 million, respectively.

(c) Interest Rate Risk

The company is exposed to interest rate risk as changes in interest rates may affect future cash flows and the fair values of its financial instruments. The primary exposure is related to its revolving-term debt of commercial papers.

To manage the company's exposure to interest rate volatility, the company may periodically enter into interest rate swap contracts. The objective of entering into these contracts is to reduce the company's cost of borrowing by managing the mix of fixed and floating interest rate debt. The proportion of floating interest rate exposure at December 31, 2012 was 8% of total debt outstanding. The weighted-average interest rate on total debt for the year ended December 31, 2012 was 6.0%.

The company's net earnings are sensitive to changes in interest rates on the floating rate portion of the company's debt. To the extent interest expense is not capitalized, if interest rates applicable to floating rate instruments increased by 1%, it is estimated that the company's pre-tax earnings would decrease by approximately $8 million. This assumes that the amount and mix of fixed and floating rate debt remains unchanged from December 31, 2012, and that the change in interest rates is effective from the beginning of the year.

2) Liquidity Risk

Liquidity risk is the risk that Suncor will not be able to meet its financial obligations when due. The company mitigates this risk by forecasting spending requirements and maintaining sufficient cash and credit facilities to meet these requirements. Suncor's cash and cash equivalents and total credit facilities at December 31, 2012 were $4.4 billion and $6.3 billion, respectively.

Surplus cash is invested into a range of short-dated money market securities. Investments are only permitted in high credit quality government or corporate securities. Diversification of these investments is maintained through counterparty credit limits.

The following table shows the timing of cash outflows related to trade and other payables and debt.

	December 31, 2012	
($ millions)	Trade and other payables [1]	Debt [2]
Within one year	**6 469**	**1 756**
1 to 3 years	**300**	**1 732**
3 to 5 years	**—**	**1 301**
Over 5 years	**—**	**17 648**
	6 769	**22 437**

(1) Includes the Fort Hills purchase obligation and the Libya EPSAs signature bonus.

(2) Debt includes short-term debt, long-term debt, finance leases and interest payments on fixed-term debt and commercial paper.

3) Credit Risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss. The company's credit policy is designed to ensure there is a standard credit practice throughout the company to measure and monitor credit risk. The policy outlines delegation of authority, the due diligence process required to approve a new customer or counterparty and the maximum amount of credit exposure per single entity. Before transactions begin with a new customer or counterparty, its creditworthiness is assessed, a credit rating is assigned and a maximum credit limit is allocated. The assessment process is outlined in the credit policy and considers both quantitative and qualitative factors. The company constantly monitors the exposure to any single customer or counterparty along with the financial position of the customer or counterparty. If it is deemed that a customer or counterparty has become materially weaker, the company will work to reduce the credit exposure and lower the credit limit allocated. Regular reports are generated to monitor credit risk and the Credit Committee meets quarterly to ensure compliance with the credit policy and review the exposures.

A substantial portion of the company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risk. At December 31, 2012, substantially all of the company's trade receivables were current. As a result of the continued political unrest in Syria, the company wrote off the remainder of its Syrian receivables ($67 million) in the second quarter of 2012. A write-down of $63 million was previously recorded at December 31, 2011.

The company may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The company's exposure is limited to those counterparties holding derivative contracts with positive fair values at the reporting date. At December 31, 2012, the company's exposure was $53 million.

27. CAPITAL STRUCTURE FINANCIAL POLICIES

The company's primary capital management objective is to maintain a conservative balance sheet, which supports a solid investment-grade credit rating profile. This objective affords the company the financial flexibility and access to the capital it requires to execute on its growth objectives.

The company's capital is primarily monitored through net debt to cash flow from operations [1] and total debt to total debt plus shareholders' equity.

Net debt to cash flow from operations is calculated as short-term debt plus total long-term debt less cash and cash equivalents divided by cash flow from operations for the year then ended.

Total debt to total debt plus shareholders' equity is calculated as short-term debt plus total long-term debt divided by short-term debt plus total long-term debt plus shareholders' equity.

Financial covenants associated with the company's various banking and debt agreements are reviewed regularly and controls are in place to maintain compliance with these covenants. The company complied with all financial covenants for the years ended December 31, 2012 and 2011.

The company's strategy during 2012, which was unchanged from 2011, was to maintain the measure set out in the following schedule. The company believes that achieving this capital target helps to provide the company access to capital at a reasonable

cost by maintaining solid investment-grade credit ratings. The company operates in a fluctuating business environment and ratios may periodically fall outside of management's targets.

At December 31 ($ millions)	Capital Measure Target	**2012**	2011
Components of ratios			
Short-term debt		**776**	763
Current portion of long-term debt		**311**	12
Long-term debt		**9 938**	10 004
Total debt		**11 025**	10 779
Less: Cash and cash equivalents		**4 393**	3 803
Net debt		**6 632**	6 976
Shareholders' equity		**39 223**	38 600
Total capitalization (total debt plus shareholders' equity)		**50 248**	49 379
Cash flow from operations [1]		**9 745**	9 746
Net debt to cash from operations	<2.0 times	**0.7**	0.7
Total debt to total debt plus shareholders' equity		**22%**	22%

(1) Cash flow from operations is expressed before changes in non-cash working capital, and is a non-GAAP financial measure.

28. INTERESTS IN JOINTLY CONTROLLED ENTITIES AND INVESTMENTS IN ASSOCIATES

Significant jointly controlled entities and associates at December 31, 2012 are set out below:

Jointly controlled entities	**%**
Fort Hills Energy L.P.	40.8
Syncrude Canada Ltd. [1]	12.0
Voyageur Upgrader L.P.	51.0
Magrath Windfarm Joint Venture	33.3
Chin Chute Windfarm Joint Venture	33.3
Ripley Windfarm Joint Venture	50.0
Wintering Hills Joint Venture	70.0
Chimies Parachem S.E.C. / Parachem Chemicals L.P.	51.0
UPI Inc.	50.0
Investments in associates	**%**
Montreal Pipeline Ltd.	23.8
Trans-Northern Pipelines Inc.	33.3

(1) Syncrude Canada Ltd. is the operator of the Syncrude oil sands joint venture, a jointly controlled asset. Syncrude Canada Ltd. is responsible for the management and administration of this asset.

Summarized financial information for the company's share of its jointly controlled entities and investments in associates are shown below:

(a) Jointly controlled entities

($ millions)	**Dec 31 2012**	Dec 31 2011
Current assets	**196**	127
Non-current assets	**1 535**	2 935
	1 731	3 062
Current liabilities	**355**	135
Non-current liabilities	**153**	146
	508	281
Revenues and other income	**533**	541
Less: Expenses	**2 432**	746
Net loss	**(1 899)**	(205)

(b) Investments in associates

($ millions)	**Dec 31 2012**	Dec 31 2011
Current assets	**7**	7
Non-current assets	**82**	84
	89	91
Current liabilities	**18**	21
Non-current liabilities	**34**	39
	52	60
Revenues and other income	**42**	38
Less: Expenses	**34**	32
Net earnings	**8**	6

29. RELATED PARTY DISCLOSURES

Related Party Transactions

The company enters into transactions with related parties in the normal course of business. These are primarily sales to associated entities in the company's refining and marketing operations. Operating revenues after eliminations for these transactions were $1,313 million for the year ended December 31, 2012 (2011 – $780 million). At December 31, 2012, amounts due from related parties were $205 million (2011 – $60 million).

Compensation of Key Management Personnel

Compensation of the company's Board of Directors and members of the Executive Leadership Team for the years ended December 31 is as follows:

($ millions)	**2012**	2011
Short-term benefits	**18**	17
Pension and other post-retirement benefits	**4**	3
Share-based compensation	**32**	29
	54	49

30. COMMITMENTS, CONTINGENCIES AND GUARANTEES

(a) Commitments

Future payments under the company's operating leases for pipeline transportation agreements and for various premises, service stations and other property and equipment are as follows:

($ millions)	Within one year	One to five years	More than five years	Total
Operating and other commitments	**1 572**	**3 973**	**8 176**	**13 721**
Exploration work commitments	**67**	**205**	**—**	**272**
At December 31, 2012	**1 639**	**4 178**	**8 176**	**13 993**

Significant operating leases expire at various dates through 2035. For the year ended December 31, 2012, operating lease expense was $1.2 billion (2011 – $1.1 billion).

In addition to the operating lease commitments in the above table, the company has other obligations for goods and services and raw materials entered into in the normal course of business, which may terminate on short notice. Such obligations include commodity purchase obligations which are transacted at market prices.

(b) Contingencies

Legal and environmental contingent liabilities

The company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

The company may also have environmental contingent liabilities, beyond decommissioning and restoration liabilities recognized in note 23, which are reviewed individually and are reflected in the company's financial statements if material and more likely than not to be incurred. These contingent environmental liabilities primarily relate to the mitigation of contamination at sites where the company has had operations. For any unrecognized environmental contingencies, the company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

Costs attributable to these commitments and contingencies are expected to be incurred over an extended period of time and to be funded from the company's cash flow from operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, the impact may be material.

Operational risk

The company also has exposure to some operational risks, which is reduced by maintaining a comprehensive insurance program at limits and deductible amounts that management believes to be acceptable.

The company carries property damage and business interruption insurance with varying coverage limits and deductible amounts based on the asset. As of December 31, 2012, Suncor's insurance program includes coverage of up to US$1.1 billion for oil sands risks, up to US$1.3 billion for offshore risks and up to US$563 million for refining risks. These limits are all net of deductible amounts or waiting periods and subject to certain price and volume limits. The company also has primary property insurance for US$300 million that covers all of Suncor's assets. As part of its normal course of operations, Suncor carries risk mitigation instruments in the aggregate amount of $405 million on certain foreign operations.

During the fourth quarter of 2012, the company received $300 million of risk mitigation proceeds related to its Syrian operations. The proceeds are subject to a provisional repayment should the company resume operations and therefore, have been recorded as a non-current provision at December 31, 2012 (see note 9).

Suncor believes its liability, property and business interruption insurance is appropriate to its business, although such insurance will not provide coverage in all circumstances or fully protect against prolonged outages. In the future, the insurance program may change due to market conditions or other business considerations.

(c) Guarantees

At December 31, 2012, the company has various indemnification agreements with third parties as described below and provides loan guarantees to certain retail licensees, wholesale marketers, and the company's subsidiaries.

The company has agreed to indemnify holders of all notes and debentures and the company's credit facility lenders (see note 20) for added costs relating to withholding taxes. Similar indemnity terms apply to certain facility and equipment leases.

There is no limit to the maximum amount payable under the indemnification agreements described above. The company is unable to determine the maximum potential amount payable as government regulations and legislation are subject to change without notice. Under these agreements, the company has the option to redeem or terminate these contracts if additional costs are incurred.

The company also has guaranteed its working interest share of certain joint venture undertakings related to transportation services agreements entered into with third parties. The guaranteed amount is limited to the company's share in the joint venture. As at December 31, 2012, the probability is remote that these guarantee commitments will impact the company.

31. TRANSACTION WITH TOTAL

During 2011, Suncor entered into a joint venture with Total E&P Canada Ltd. (Total). As a result of this transaction, Suncor acquired a 36.75% interest in Joslyn for consideration of $842 million after closing adjustments. Total acquired a 49% interest in Voyageur, a 19.2% increase in its interest in Fort Hills (reducing Suncor's interest from 60% to 40.8%), and rights to proprietary mining technology, for cash consideration of $2.662 billion after closing adjustments.

Overall, Suncor recognized a loss of $124 million, after final closing adjustments, related to the disposition of its interests in Voyageur and Fort Hills and the technology sale. The loss included the derecognition of $267 million of goodwill associated with the disposed interests in Fort Hills and Voyageur.

32. SUSPENDED EXPLORATORY WELL COSTS

($ millions)	**2012**	2011
Beginning of year	**387**	266
Additions	**4**	122
Transfers to oil and gas assets	**—**	—
Capitalized exploratory well costs charged to expense	**(73)**	(1)
Foreign exchange adjustments	**—**	—
End of year	**318**	387

The following provides an aging of amounts capitalized as suspended exploratory wells at December 31 based on the completion date of the individual well.

($ millions)	**2012**	2011
Suspended exploratory well costs that have been capitalized for a period less than one year	**4**	122
Suspended exploratory well costs that have been capitalized for a period greater than one year	**314**	265
	318	387
Number of suspended exploratory wells that have been capitalized for a period greater than one year	**8**	9

Suspended capitalized costs for exploratory wells completed prior to the end of 2012 are associated with the following projects located in i) Norway (three wells), ii) Libya (four wells) and iii) East Coast Canada (one well). The projects are awaiting the completion of economic evaluations including, but not limited to, results of additional appraisal drilling, additional geological and geophysical data, and development plan approval.

QuickLinks

EXHIBIT 99-1

Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2012

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 99-2

**Management's Discussion and Analysis for the fiscal year ended December 31, 2012,
dated February 26, 2013**

This Management's Discussion and Analysis (MD&A) should be read in conjunction with Suncor's December 31, 2012 audited Consolidated Financial Statements and the accompanying notes. Additional information about Suncor filed with Canadian securities regulatory authorities and the United States Securities and Exchange Commission (SEC), including quarterly and annual reports and the Annual Information Form dated March 1, 2013 (the 2012 AIF), which is also filed with the SEC under cover of Form 40-F, is available online at www.sedar.com, www.sec.gov and our website, www.suncor.com. Information contained in or otherwise accessible through our website does not form a part of this MD&A, and is not incorporated into this MD&A by reference.

References to "we", "our", "Suncor", or "the company" mean Suncor Energy Inc., its subsidiaries, partnerships and joint arrangements, unless the context requires otherwise.

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Basis of Presentation

Unless otherwise noted, all financial information has been prepared in accordance with Canadian generally accepted accounting principles (GAAP), which is within Part 1 of the Canadian Institute of Chartered Accountants Handbook, which itself is within the framework of International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board.

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 prior year amounts in the Consolidated Statements of Comprehensive Income have been reclassified to conform to the current year's presentation.

Non-GAAP Financial Measures

Certain financial measures in this MD&A – namely operating earnings, cash flow from operations, return on capital employed (ROCE) and Oil Sands cash operating costs – are not prescribed by GAAP. Operating earnings and Oil Sands cash operating costs are defined in the Non-GAAP Financial Measures Advisory section of this MD&A and reconciled to GAAP measures in the Consolidated Financial Information and Segment Results and Analysis sections of this MD&A. Cash flow from operations and ROCE are defined and reconciled to GAAP measures in the Non-GAAP Financial Measures Advisory section of this MD&A.

These non-GAAP financial measures are included because management uses the information to analyze operating performance, leverage and liquidity. These non-GAAP financial measures do not have any standardized meaning and, therefore, are unlikely to be comparable to similar measures presented by other companies and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP.

Common Abbreviations

The following is a list of abbreviations that may be used in this MD&A:

Measurement

bbl	barrel
bbls/d	barrels per day
mbbls/d or kbpd	thousands of barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mcf	thousands of cubic feet of natural gas
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
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
m^3	cubic metres
m^3/d	cubic metres per day
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

Financial and Business Environment

DD&A	Depreciation, depletion and amortization
WTI	West Texas Intermediate
WCS	Western Canadian Select
SCO	Synthetic crude oil
NYMEX	New York Mercantile Exchange

Risk Factors and Forward-Looking Information

The company's financial and operational performance is potentially affected by a number of factors, including, but not limited to, the volatility of commodity prices and exchange rate fluctuations; government regulation, including changes to royalty and income tax legislation and the interpretation and implementation thereof; environmental regulation, including changes to climate change and reclamation legislation; risks associated with operating in foreign countries, including geopolitical and other political risks; operating hazards and other uncertainties, including extreme weather conditions, fires, explosions and oil spills; risks associated with the execution of major projects; reputational risk; permit approval; labour and materials supply; and other issues described within the Advisory – Forward-Looking Information section of this MD&A.

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

Measurement Conversions

Certain crude oil and natural gas liquids volumes have been converted to mcfe or mmcfe on the basis of one bbl to six mcf. Also, certain natural gas volumes have been converted to boe or mboe on the same basis. Any figure presented in mcfe, mmcfe, boe or mboe may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or natural gas liquids to six mcf of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, conversion on a 6:1 basis may be misleading as an indication of value.

2. 2012 HIGHLIGHTS

- **Suncor reports strong operating earnings and cash flow from operations.**
  - Net earnings for 2012 were $2.783 billion, compared to $4.304 billion in 2011.
  - Operating earnings [(1)] for 2012 were $4.890 billion, compared to $5.674 billion in 2011.
  - Cash flow from operations [(1)] for 2012 was $9.745 billion, compared to $9.746 billion in 2011.
  - ROCE [(1)] (excluding major projects in progress) was 7.3% for the twelve months ended December 31, 2012, compared to 13.8% for the twelve months ended December 31, 2011. ROCE was impacted by approximately 4% due to an after-tax impairment of $1.487 billion for the Voyageur upgrader project.

- **Suncor's integrated business model translates low mid-continent crude oil prices to high refining margins.**

  The Refining and Marketing segment contributed over $3.1 billion to cash flow from operations in 2012 compared to $2.6 billion in 2011, reinforcing the value of an integrated business model to Suncor's consolidated results. Suncor's inland refineries benefited from discounts for mid-continent crude feedstock produced in our Oil Sands operations. Demonstrated reliability and continuous improvements of the company's refining facilities resulted in 95% overall refinery utilization in 2012, further contributing to the strength of Suncor's integrated model.

- **Suncor's balance sheet remains strong and primed for future growth.**

  Significant cash flow from the company's integrated and diverse operations and a disciplined approach to spending solidified Suncor's financial position.
  - Cash flow from operations for 2012 exceeded capital and exploration expenditures (including capitalized interest) by over $2.7 billion, and were higher than net debt at year end by $3.1 billion.
  - Net debt at December 31, 2012 was $6.6 billion, and decreased from $7.0 billion at December 31, 2011. Cash and cash equivalents at December 31, 2012 were $4.4 billion and increased from $3.8 billion at December 31, 2011.

- **Suncor returns cash to shareholders.**

  Suncor shareholders received over $2.2 billion in cash from the company during 2012 through share repurchases and dividends.
  - The company returned $1.5 billion to shareholders through the repurchase of 46.9 million common shares in 2012, at a weighted average price of $30.96 per share. The completion of the $1.5 billion share repurchase program that was initiated in 2011 and additional repurchases under the $1.0 billion program announced in 2012 resulted in a $1.0 billion increase in repurchases over the prior year.
  - The company increased its quarterly dividend by 18% to $0.13 per common share.

- **Bitumen production from Firebag increases by 75% resulting in record production for the Oil Sands.**

  Knowledge and expertise gained through previous Firebag construction phases were applied to Firebag Stage 4, resulting in timely execution, reliable operations and effective cost control.
  - Average production in 2012 increased to 104,000 bbls/d from 59,500 bbls/d in 2011. Suncor expects to approach production capacity of 180,000 bbls/d over the next year.
  - Cogeneration units for Stage 4 were completed ahead of schedule and steam injection for both well pads was in progress by the end of 2012. Stage 4 central processing facilities operated at 10% capacity throughout the fourth quarter, enabling the company to process incremental bitumen supply from Stage 3 wells and infill drilling projects.
  - Stage 4 was executed ahead of schedule and is expected to be approximately 15% below the announced cost estimate of $2.0 billion.

- **Execution of major capital projects adds value to Suncor.**
  - The company completed the Millennium Naphtha Unit (MNU) in 2012. The company expects that the MNU will increase sweet SCO production capacity by approximately 10% and stabilize secondary upgrading processes by providing flexibility during maintenance.
  - The company completed its tailings management (TRO $_{TM}$) project in 2012, which has set the foundation for Suncor's TRO $_{TM}$ process. Through the TRO$_{TM}$

process, mature fine tailings are converted more rapidly into a solid landscape suitable for reclamation.

- The development of the North Steepbank mining area provided Suncor with access to a significant reserves base. The full ramp up of production from the North Steepbank mining area resulted in efficiencies through reduced mine congestion and lower average haul distances.

- **Suncor offers attractive prospects for long-term profitable growth.**

In support of Suncor's capital discipline initiative, growth capital for 2013 is focused on high return projects, reflecting a balance between projects in the Oil Sands and Exploration and Production segments.

- Suncor continues to focus on the optimization of assets and construction of infrastructure to enhance regional takeaway capacity and marketing flexibility of Oil Sands production. In support of these initiatives, the Wood Buffalo pipeline and two of four storage tanks at Hardisty, Alberta were commissioned in late 2012, and various debottlenecking projects in the Oil Sands operations are currently underway.
- In the Exploration and Production segment, the company will continue to advance the Hebron and Golden Eagle Area Development (Golden Eagle) projects. In 2012, the company and the co-owners of Hebron announced project sanction. The estimated gross oil production capacity for Hebron is 150,000 bbls/d. First oil is targeted for late 2017.
- Growth capital in Refining and Marketing will be focused on projects to prepare the Montreal refinery to receive shipments of western crude feedstock.

- **Suncor continues to evaluate a suite of growth opportunities.**

- Suncor's Oil Sands Ventures business, dedicated to ensuring the success of Suncor's joint arrangements, continued to work closely with other owners on evaluating and progressing growth projects, including the Fort Hills and Joslyn North mining projects, and the Voyageur upgrader.
- With a significant reserves and resources base, Suncor continues to assess potential in situ growth prospects at Firebag, MacKay River, Meadow Creek and Lewis.
- Suncor continues to explore offshore prospects in Norway and the U.K. North Sea.

- **A continued focus on operational excellence and improved reliability.**

- Demonstrated reliability and continuous improvements at Suncor's refineries resulted in nameplate capacity increases for three out of four refineries since 2011, and an overall refinery utilization rate of 95% for 2012.
- Although 2012 was a challenging year in terms of reliability for upgrading facilities, Suncor's underlying cost discipline and performance trends were positive, as reflected in a $2/bbl decrease in cash operating costs [(1)] per barrel from $39.05 in 2011 to $37.05 for Suncor's Oil Sands operations in 2012. Suncor continued to work towards higher reliability in 2012 with the completion of planned maintenance on several coker units and hydrotreaters at Upgrader 1 and 2.
- Suncor executed planned maintenance on all offshore producing assets in 2012, including the repair of the propulsion system at White Rose, and the replacement of the water injection swivel and subsea infrastructure at Terra Nova. Production at Terra Nova resumed from the largest drill centre in December 2012, while production from a second drill centre was delayed until February 2013. The third drill centre is expected to be commissioned in the third quarter of 2013.

- **Operations resumed in Libya, but remained suspended in Syria.**

- Subsequent to the successful restart of production in late 2011, average production from Libya exceeded 40,000 boe/d. In 2013, Suncor plans to continue the redevelopment of existing fields and resume exploration activities.
- As a result of the political unrest that began in Syria in the latter half of 2011 and ensuing international sanctions, Suncor declared force majeure under its contractual obligations and suspended operations in the country in December 2011. The company has ceased recording all production and revenue and continues to comply with all applicable sanctions. Suncor received $300 million in risk mitigation proceeds in 2012, which are subject to a provisional repayment should operations resume in Syria.

- **Suncor continues to invest in renewable energy assets.**

The company continues to progress the Adelaide and Cedar Point wind projects through the regulatory process in 2013. The two projects are expected to add 140 MW of gross installed capacity, increasing the gross installed capacity of Suncor's wind projects by 55%.

(1) Operating earnings, cash flow from operations, ROCE and Oil Sands cash operating costs are non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

3. SUNCOR OVERVIEW

Suncor is an integrated energy company headquartered in Calgary, Alberta, 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 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 Exploration and Production Sharing Agreements (EPSAs), working interests in the exploration and development of oilfields in the Sirte Basin in Libya. Suncor also owns, pursuant to a Production Sharing Contract (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, two wind power projects under development in Ontario, 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.

4. CONSOLIDATED FINANCIAL INFORMATION

Financial Highlights

Year ended December 31 ($ millions, except per share amounts)	**2012**	2011	2010
Net earnings	**2 783**	4 304	3 829
per common share – basic	**1.80**	2.74	2.45
per common share – diluted	**1.79**	2.67	2.43
Operating earnings [1]	**4 890**	5 674	2 634
per common share – basic	**3.17**	3.61	1.69
Cash flow from operations [1]	**9 745**	9 746	6 656
per common share – basic	**6.31**	6.20	4.25
Dividends on common shares [2]	**756**	664	611
per common share – basic	**0.50**	0.43	0.40
Operating revenues, net of royalties [3]	**38 208**	38 339	31 315
ROCE [1][4] (%)			
For the twelve months ended	**7.3**	13.8	11.4
Balance Sheet			
Total assets	**76 449**	74 777	68 607
Long-term debt [5]	**10 249**	10 016	10 347
Net debt	**6 632**	6 976	11 254

Segment Highlights

Year ended December 31 ($ millions)	**2012**	2011	2010
Net earnings (loss)			
Oil Sands	**458**	2 603	1 520
Exploration and Production	**138**	306	1 938
Refining and Marketing	**2 129**	1 726	819
Corporate, Energy Trading and Eliminations	**58**	(331)	(448)
Total	**2 783**	4 304	3 829
Operating earnings (loss) [1]			
Oil Sands	**2 015**	2 737	1 379
Exploration and Production	**850**	1 358	1 193
Refining and Marketing	**2 144**	1 726	796
Corporate, Energy Trading and Eliminations	**(119)**	(147)	(734)
Total	**4 890**	5 674	2 634
Cash flow from operations [1]			
Oil Sands	**4 407**	4 572	2 777
Exploration and Production	**2 227**	2 846	3 325
Refining and Marketing	**3 150**	2 574	1 538
Corporate, Energy Trading and Eliminations	**(39)**	(246)	(984)
Total	**9 745**	9 746	6 656

(1) Non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) Dividends paid on common shares does not include a value for common share dividends granted under the company's dividend reinvestment program.

(3) The company has reclassified prior year operating revenues to reflect net presentation of certain transactions involving sales and purchases of third-party crude oil production in the Oil Sands segment that were previously presented on a gross basis.

(4) Excludes capitalized costs related to major projects in progress.

(5) Includes current portion of long-term debt.

Operating Highlights

Year ended December 31	**2012**	2011	2010
Production Volumes (mboe/d)			
Oil Sands	**359.2**	339.3	318.2
Exploration and Production	**189.9**	206.7	296.9
	549.1	546.0	615.1
Price Realizations ($/boe)			
Oil Sands	**82.75**	90.07	70.85
Exploration and Production	**84.05**	79.95	61.06
	83.20	86.23	66.12
Refinery Utilization [1][2] (%)			
Eastern North America	**89**	94	89
Western North America	**100**	91	95
	95	92	92

(1) Effective January 1, 2012, the company increased the nameplate capacity of the Montreal refinery from 130,000 bbls/d to 137,000 bbls/d and the nameplate capacity of the Commerce City refinery from 93,000 bbls/d to 98,000 bbls/d. Prior years' utilization rates have not been recalculated and reflect the lower nameplate capacities. Effective January 1, 2013, the company increased the nameplate capacity of the Edmonton refinery from 135,000 bbls/d to 140,000 bbls/d. Figures above have not been recalculated to reflect the revised nameplate capacity.

(2) Refinery utilization is the amount of crude oil and natural gas plant liquids run through crude distillation units, expressed as a percentage of the capacity of these units.

Production volumes for 2012 increased relative to 2011. Suncor achieved average production in the Oil Sands segment of 359,200 bbls/d in 2012 compared to 339,300 bbls/d in 2011. The increase was due primarily to the ramp up of production from Firebag, partially offset by the impact of constrained upgrader availability on mine production, due to planned and unplanned maintenance in 2012.

Production in the Exploration and Production segment was lower in 2012 compared with 2011 due to planned maintenance activities, the suspension of operations in Syria due to political unrest and international sanctions, and the shut in of natural gas wells in 2012 in response to low North American natural gas prices. This was partially offset by the resumption of production in Libya.

Net Earnings

Suncor's net earnings for 2012 were $2.783 billion, compared to $4.304 billion in 2011. Net earnings were affected by the same factors that influenced operating earnings, which are described in this section of the MD&A under the heading Operating Earnings. Other items affecting changes in net earnings in 2012, compared with 2011, included:

Operating Earnings Adjustments

- The after-tax unrealized foreign exchange gain on the revaluation of U.S. dollar denominated long-term debt was $157 million in 2012, compared with a loss of $161 million in 2011.
- In 2012, the company recorded after-tax impairments (net of reversals), write-offs and provisions of $2.176 billion. Given Suncor's view of the challenging economic outlook for the Voyageur upgrader project, at December 31, 2012, Suncor performed an impairment test. Based on an assessment of expected future net cash flows, the company recorded an after-tax impairment charge of $1.487 billion. Due to political unrest and international sanctions against Syria, Suncor recorded an after-tax impairment (net of reversals) and write-offs for assets in Syria of $517 million. Additional impairments in 2012 included after-tax impairment charges of $65 million to reflect future development uncertainty relating to certain exploration assets in East Coast Canada and North America Onshore, and an after-tax impairment charge of $63 million for certain North America Onshore properties due to a decline in price forecasts. In addition, the company recorded an after-tax provision of $44 million in North America Onshore relating to future commitments for unutilized pipeline capacity.
- In 2012, the Province of Ontario approved a budget that froze the general corporate income tax rate at 11.5%, instead of the planned reduction to 10% by 2014. As a result, the company adjusted its deferred income tax balances leading to a one-time negative adjustment to net earnings of $88 million.
- In 2011, the company recorded net impairment charges of $503 million against assets pertaining to its operations in Libya, which were shut in as a result of political unrest. In 2011, the company also recorded $68 million of after-tax impairment charges against certain North America Onshore assets due to decreasing natural gas prices and after-tax write-offs of crude inventories of $58 million due primarily to third-party pipeline adjustments.

- In the first quarter of 2011, the U.K. government announced an increase in the tax rate on oil and gas profits in the North Sea that increased the effective tax rate on Suncor's earnings in the U.K. from 50% to 59.3% in 2011 and to 62% in future years. As a result, the company revalued its deferred income tax balances, resulting in an increase to deferred income tax expense of $442 million.

- In 2011, the company disposed of assets resulting in after-tax losses of $107 million, consisting of $99 million on the partial disposition of interests in the Voyageur upgrader and Fort Hills projects, and $8 million for the sale of non-core Exploration and Production assets.

- In 2011, Suncor recorded an after-tax provision of $31 million in the Exploration and Production segment related to a royalty dispute concerning the deductibility of certain costs for a period before the merger with Petro-Canada.

Operating Earnings

Consolidated Operating Earnings Reconciliation (1)

Year ended December 31 ($ millions)	**2012**	2011	2010
Net earnings as reported	**2 783**	4 304	3 829
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(157)**	161	(372)
Impairments (net of reversals), write-offs, and provisions	**2 176**	629	306
Impact of income tax rate adjustments on deferred income taxes	**88**	442	—
Loss (gain) on significant disposals (2)	**—**	107	(826)
Adjustments to provisions for assets acquired through the merger (3)	**—**	31	68
Change in fair value of commodity derivatives used for risk management, net of realizations (4)	**—**	—	(233)
Redetermination of working interest in Terra Nova (5)	**—**	—	(166)
Modification of the bitumen valuation methodology (6)	**—**	—	(51)
Merger and integration costs	**—**	—	79
Operating earnings (1)	**4 890**	5 674	2 634

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) In 2010, the company sold several Exploration and Production assets, including non-core assets in North America Onshore and the U.K. and those in the Netherlands and Trinidad and Tobago, and realized after-tax gains on the disposals of $826 million.

(3) Adjustments in 2010 were for pipeline commitments that the company determined to be unfavourable as a result of certain non-core North America Onshore asset dispositions, the write-off of certain unproven properties in the Exploration and Production segment, changes in the provision for the cancellation of the Montreal refinery coker project, a dry hole in Libya, and other cost estimates associated with the transition to EPSAs in Libya.

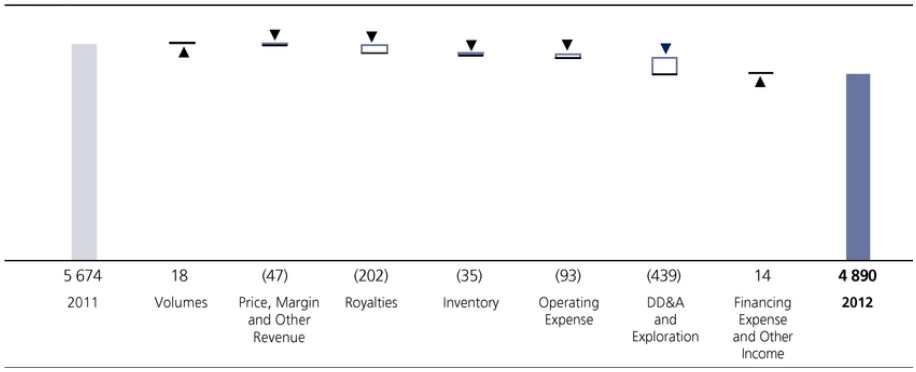
(4) Adjustments in 2010 represent the change in fair value of significant crude oil risk management derivatives, net of realized gains and losses recognized on the final settlement of those derivatives. The company also holds less significant risk management derivatives for which the company does not adjust net earnings.

(5) In 2010, Suncor recognized an after-tax gain of $166 million for the redetermination of its working interest in the Terra Nova oilfield, upon which the co-owners of Terra Nova reached agreement on a technical review of interests they contributed.

(6) In 2010, Suncor recognized a favourable royalty recovery related to modifications made by the Alberta government to the Bitumen Valuation Methodology (BVM) calculation applicable to Suncor for the interim period from January 1, 2009 to December 31, 2010.

Bridge Analysis of Consolidated Operating Earnings[1]

($ millions)



(1) For an explanation of the construction of this bridge analysis, see the Non-GAAP Financial Measures Advisory section of this MD&A.

Suncor's consolidated operating earnings for 2012 were $4.890 billion, compared to $5.674 billion in 2011. Factors that reduced operating earnings in 2012, compared to 2011, included:

- Production volumes from the Exploration and Production segment were lower in 2012, due primarily to planned off-station maintenance programs at Terra Nova and subsequent delays in reconnecting flow lines, planned maintenance at White Rose, the suspension of operations in Syria, and declines in production in North America Onshore, partially offset by the resumption of operations in Libya.
- Average price realizations for production from Oil Sands operations were lower in 2012, due primarily to lower premiums for sweet SCO relative to WTI, and wider light/heavy differentials that impacted prices for sour SCO and bitumen.
- Royalties were higher in 2012, compared with 2011, due primarily to higher production from Libya, where effective royalty rates are substantially higher than those for other Exploration and Production assets.
- The Inventory variance factor was negative, primarily due to an inventory build in Oil Sands in 2012 to fill new logistics infrastructure, including the Wood Buffalo pipeline and storage tanks in Hardisty, Alberta.
- Operating expenses increased due primarily to an increase in share-based compensation expense of $353 million in 2012 compared to 2011, as a result of an increase in the company's common share price from December 31, 2011 to December 31, 2012.
- DD&A and exploration expenses were higher in 2012 relative to 2011 due primarily to a larger asset base as a result of assets commissioned in 2012 and late 2011, higher exploration write-offs, partially offset by less DD&A expense related to lower production in the Exploration and Production segment.
- Operating earnings for International assets were also negatively impacted by a higher effective tax rate in the U.K.

The following factors had a positive impact on operating earnings in 2012 compared to 2011:

- Production volumes in the Oil Sands segment increased to 359,200 bbls/d in 2012 from 339,300 bbls/d in 2011, primarily due to the ramp up of Firebag production.
- Refining and marketing achieved record operating earnings in 2012 and absorbed much of the negative impact that low synthetic and heavy crude pricing had on the Oil Sands segment. Refining margins were higher in 2012 due to lower feedstock costs and higher crack spreads compared to 2011 and continued reliability from the company's refineries.

Cash Flow from Operations

Consolidated cash flow from operations for 2012 was $9.745 billion, compared to $9.746 billion in 2011. Cash flow from operations was impacted by lower price realizations in the Oil Sands segment, partially offset by strong refining margins. Lower production in the Exploration and Production segment was offset by the increase in the production from the Oil Sands segment.

Results for 2011 compared with 2010

Net earnings for 2011 were $4.304 billion compared to $3.829 billion in 2010. The increase in net earnings was due mainly to the same factors impacting operating earnings, partially offset by the operating earnings adjustments described above, such as the impact of unrealized foreign exchange gains and losses on U.S. dollar denominated long-term debt, the impairment of assets in Libya, the increase in the U.K. tax rate and gains and losses on the disposal of significant assets.

Operating earnings for 2011 were $5.674 billion compared to $2.634 billion in 2010. The increase in operating earnings was due mainly to higher average upstream price realizations for crude oil production, higher refining margins and an increase in production from Oil Sands, where volumes were impacted in the first half of 2010 by two upgrader fires. These increases were partially offset by lower production volumes for the Exploration and Production segment, due mainly to the divestiture of non-core assets throughout 2010 and 2011, and higher operating expenses, primarily due to incremental costs associated with Firebag Stage 3.

Cash flow from operations was $9.746 billion in 2011, compared to $6.656 billion in 2010, and increased due mainly to the same factors impacting operating earnings.

Net debt decreased by $4.278 billion in 2011, due primarily to strong cash flow from operations that exceeded capital expenditures (including capitalized interest) by $2.890 billion and proceeds of $2.232 billion that were received from the Total E&P Canada Ltd. (Total E&P) transaction and the sale of non-core assets in 2011. These factors enabled Suncor to reduce short-term and long-term debt by $1.721 billion and maintain a larger balance of cash and cash equivalents in 2011.

Business Environment

Commodity prices, refining crack spreads and foreign exchange rates are important factors that affect the results of Suncor's operations.

Year ended December 31	**2012**	2011	2010
WTI crude oil at Cushing (US$/bbl)	**94.20**	95.10	79.55
Dated Brent crude oil at Sullom Voe (US$/bbl)	**111.70**	111.15	79.50
Dated Brent/Maya FOB price differential (US$/bbl)	**12.15**	12.50	9.30
Canadian 0.3% par crude oil at Edmonton (Cdn$/bbl)	**86.60**	95.75	78.05
WCS at Hardisty (US$/bbl)	**73.15**	77.95	65.35
Light/heavy differential for WTI at Cushing less WCS at Hardisty (US$/bbl)	**21.05**	17.15	14.20
Condensate at Edmonton (US$/bbl)	**100.75**	105.30	81.90
Natural gas (Alberta spot) at AECO (Cdn$/mcf)	**2.40**	3.65	4.15
New York Harbor 3-2-1 crack (1) (US$/bbl)	**32.90**	27.00	10.55
Chicago 3-2-1 crack (1) (US$/bbl)	**27.40**	24.65	9.00
Portland 3-2-1 crack (1) (US$/bbl)	**33.40**	28.40	13.55
Gulf Coast 3-2-1 crack (1) (US$/bbl)	**29.00**	24.80	9.00
Exchange rate (US$/Cdn$)	**1.00**	1.01	0.97
Exchange rate (end of period) (US$/Cdn$)	**1.01**	0.98	1.01

(1) 3-2-1 crack spreads are indicators of the refining margin generated by converting three barrels of WTI into two barrels of gasoline and one barrel of diesel. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

Suncor's sweet SCO price realizations are influenced by changes in the price for WTI at Cushing and by the supply and demand of sweet SCO from Western Canada. The average price for WTI in 2012 was US$94.20/bbl and was comparable to the average in 2011 of US$95.10/bbl. In 2012, the WTI price declined as the year progressed and reached its lowest level over the last two years. In 2012 due to oversupply, the average premium for sweet SCO was significantly lower than 2011.

Suncor produces a specific grade of sour SCO, the price realizations for which are influenced by changes to various crude benchmarks including, but not limited to, Canadian par crude at Edmonton and WCS at Hardisty, but which can also be affected by prices negotiated for spot sales. Prices for Canadian par crude at Edmonton decreased significantly in 2012, compared to 2011. The average Edmonton par price was $86.60/bbl in 2012 and $95.75/bbl in 2011. Average prices for WCS also decreased from US$77.95/bbl in 2011 to US$73.15/bbl in 2012. The differential between WTI and WCS reached its highest levels over the last two years, which was reflected in unfavourable sour SCO pricing.

Bitumen production that Suncor does not upgrade is blended with diluent (or SCO) to facilitate delivery on pipeline systems to customers. Net bitumen price realizations are, therefore, influenced by both prices for Canadian heavy crude oil (WCS at Hardisty is a common reference) and prices for diluent (Condensate at

Edmonton). Diluent is sourced primarily from the company's own upgrading and refining facilities; however, purchases of diluent from third parties may be required when the company experiences operational outages. Bitumen price realizations can also be affected by bitumen quality and spot sales to manage inventory levels. Average price realizations for bitumen in 2012 were lower than those realized in 2011, due mainly to wider light/heavy differentials, offset by lower prices for diluent. Suncor's integration with inland refineries in the Refining and Marketing segment is recovering much of the impact from widening crude price differentials through lower feedstock costs.

Suncor's price realizations for production from East Coast Canada and International assets are influenced primarily by the price for Brent crude. Brent crude pricing remained strong throughout 2012 and averaged US$111.70/bbl, consistent with the average of US$111.15/bbl in 2011. After reaching an average of US$118.35/bbl in the first quarter of 2012, the Brent crude price stabilized throughout the remainder of the year despite the decline in WTI, resulting in significantly higher premiums to WTI in late 2012.

Suncor's price realizations for North America Onshore natural gas production are primarily referenced to Alberta spot at AECO. The AECO benchmark declined significantly with an average of $2.40/mcf in 2012 compared to $3.65/mcf in 2011.

Suncor's refining margins are influenced primarily by 3-2-1 crack spreads, which are industry indicators approximating the gross margin on a barrel of crude oil that is refined to produce gasoline and distillates, and by light/heavy and light/sour crude differentials, which influence feedstock costs for more complex refineries that process less expensive, heavier crudes. Crack spreads do not necessarily reflect the margins of a specific refinery because these benchmarks are calculated based off of WTI. In 2012, crack spreads increased relative to 2011, in part because refined product prices reflected the higher priced Brent crude feedstock of coastal North American markets. This benefited all of Suncor's refineries for much of 2012. Specific refinery margins are further impacted by actual crude purchase costs, refinery configuration and refined product sales markets unique to that refinery's supply orbit.

The majority of Suncor's revenues from the sale of oil and natural gas commodities are based on prices that are determined by, or referenced to, U.S. dollar benchmark prices. The majority of Suncor's expenditures are realized in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease revenue received from the sale of commodities. A decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of commodities.

Conversely, many of Suncor's assets and liabilities are denominated in U.S. dollars, most notably much of the company's long-term debt, and translated to Suncor's reporting currency (Canadian dollars) at each balance sheet date. An increase in the value of the Canadian dollar relative to the U.S. dollar from the previous balance sheet date decreases the Canadian dollars required to settle U.S. dollar denominated obligations.

Economic Sensitivities [1][2][3]

The following table illustrates the estimated effects that changes in certain factors would have had on 2012 net earnings and cash flow from operations if the listed changes had occurred.

(Estimated change, in $ millions)	Net Earnings	Cash Flow From Operations
Crude oil +US$1.00/bbl	88	115
Natural gas +Cdn$0.10/mcf	(3)	(4)
Light/heavy differential +US$1.00/bbl	30	40
3-2-1 crack spreads +US$1.00/bbl	109	140
Foreign exchange +$0.01 US$/Cdn$	(42)	(145)

(1) Each line item in this table shows the effects of a change in that variable only, with other variables being held consistent.

(2) Changes for a variable imply that all such similar variables are impacted, such that Suncor's average price realizations increase uniformly. For instance, "Crude oil +US$1.00/bbl" implies that price realizations influenced by WTI, Brent, SCO, WCS, par crude at Edmonton and condensate all increase by US$1.00/bbl.

(3) Differences between estimates for net earnings and cash flow from operations are due primarily to the impacts of cash taxes in certain jurisdictions.

5. SEGMENT RESULTS AND ANALYSIS

OIL SANDS

Strategy and Operational Update

In 2012, the Oil Sands business achieved a number of milestones that contributed to record production.

Firebag Stage 3 reached full ramp up in 2012, while the successful execution of Firebag Stage 4 resulted in first oil from Stage 4 wells in 2012, as well as the commissioning of the central processing facilities and cogeneration units ahead of schedule. The project is near completion and expected to come in approximately 15% under the announced cost estimate. The company anticipates that bitumen production from the Firebag complex will reach production capacity of 180,000 bbls/d over the next year.

With the commissioning of the MNU in the third quarter of 2012, Suncor's upgrading facilities have the ability to generate a larger proportion of higher value SCO. The development of the North Steepbank mining area has provided access to a significant reserves base, and resulted in efficiencies in the mine through reduced mine congestion and lower average haul distances. The company also completed its tailings management project. Through the TRO$_{TM}$ process, mature fine tailings are converted more rapidly into a solid landscape 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.

While growth in 2012 was achieved through the successful execution of major capital projects, the focus in 2013 will be to optimize our current asset base through the development of new infrastructure that will enhance regional takeaway capacity and marketing flexibility, and debottlenecking projects that are expected to provide low-cost efficiencies and higher outputs in Oil Sands operations. In support of these initiatives, the Wood Buffalo pipeline and two of four storage tanks at Hardisty, Alberta were commissioned in late 2012.

The company will also continue to focus on steady production growth and sustainment through active infill and development drilling programs at both Firebag and MacKay River. In addition, the company has commenced a debottlenecking project at the MacKay River central processing facility and expects to increase production to 38,000 bbls/d by 2015.

With a significant resource base, Suncor continues to assess potential in situ growth prospects at Firebag, MacKay River, Meadow Creek and Lewis. Furthermore, Suncor's portfolio of technology projects will not only drive improvements and efficiencies in current production but facilitate in developing these future opportunities. This portfolio focuses on both subsurface and surface challenges, such as reducing steam-to-oil ratios and improving operational efficiency.

The Oil Sands business continues to focus on safe, reliable operations that achieve steady production growth while effectively controlling operating costs. We expect our operational excellence initiatives will continuously improve our plant utilization and workforce productivity. 2012 was a challenging year in terms of reliability in upgrading facilities; however, Suncor continues to work towards higher reliability.

Suncor's Oil Sands Ventures business, dedicated to ensuring the success of new joint arrangements in Alberta's oil sands, continued to work closely with other owners on evaluating and progressing growth projects, including the Fort Hills and Joslyn North mining projects, and the Voyageur upgrader.

The partners in the Fort Hills mining project expect to reach a sanction decision in the second half of 2013. Subject to the owners approving the sanction of the project, post sanction activities are expected to include the commencement of detailed engineering design, bulk equipment and material procurement, and site construction. Suncor plans to provide an update on the targeted timing for a sanction decision on the Joslyn mining 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.

Financial Highlights

Year ended December 31 ($ millions)	**2012**	2011	2010
Gross revenues [1]	**11 502**	12 003	9 002
Less: Royalties	**(684)**	(799)	(681)
Operating revenues, net of royalties [1]	**10 818**	11 204	8 321
Net earnings	**458**	2 603	1 520
Operating earnings [2]			
Oil Sands	**1 797**	2 425	1 196
Oil Sands Ventures	**218**	312	183
	2 015	2 737	1 379
Cash flow from operations [2]	**4 407**	4 572	2 777

(1) The company has reclassified prior years' gross revenues and operating revenues to reflect net presentation of certain transactions involving sales and purchases of third-party crude oil production in the Oil Sands segment that were previously presented on a gross basis.

(2) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Oil Sands segment net earnings for 2012 were $458 million, compared to $2.603 billion in 2011. Given the challenging economic outlook for the Voyageur upgrader project, the company performed an impairment test in 2012, based on an assessment of expected future net cash flows; the company recorded an after-tax impairment charge of $1.487 billion. Net earnings were further reduced for 2012 due to a deferred tax adjustment of $70 million related to an income tax rate change. Net earnings for 2011 included a loss of $99 million on the sale of partial interests in the Voyageur upgrader project and the Fort Hills mining project and an after-tax write-off of $35 million for third-party pipeline adjustments.

Oil Sands operations contributed $1.797 billion to operating earnings, while Oil Sands Ventures contributed $218 million. The decrease in operating earnings for Oil Sands operations from $2.425 billion in 2011 to $1.797 billion in 2012 was due primarily to lower price realizations and higher DD&A, partially offset by higher bitumen sales volumes. Operating earnings for Oil Sands Ventures decreased from $312 million in 2011 to $218 million in 2012, due primarily to lower price realizations at Syncrude.

Cash flow from operations for the Oil Sands segment was $4.407 billion in 2012, compared to $4.572 billion in 2011. The decrease was due primarily to lower price realizations, partially offset by higher bitumen sales volumes.

Operating Earnings

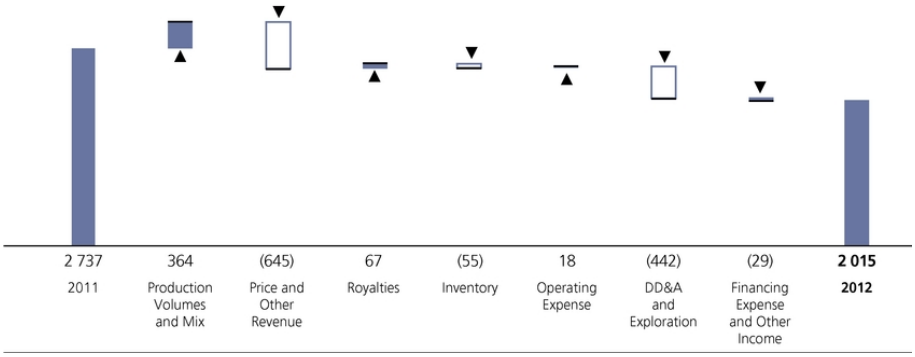
Operating Earnings Reconciliation

Year ended December 31 ($ millions)	**2012**	2011	2010
Net earnings as reported	**458**	2 603	1 520
Impairments and write-offs	**1 487**	35	143
Impact of income tax rate adjustments on deferred income taxes	**70**	—	—
Loss on significant disposals	**—**	99	—
Change in fair value of commodity derivatives used for risk management, net of realizations	**—**	—	(233)
Modification of the BVM	**—**	—	(51)
Operating earnings [1]	**2 015**	2 737	1 379

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Operating Earnings[1]

($ millions)



(1) For an explanation of the construction of this bridge analysis, see the Non-GAAP Financial Measures Advisory section of this MD&A.

Production Volumes [1]

Year ended December 31 (mbbls/d)	**2012**	2011	2010
Upgraded product (SCO)	**276.7**	279.7	251.4
Non-upgraded bitumen	**48.1**	25.0	31.6
Oil Sands	**324.8**	304.7	283.0
Oil Sands Ventures – Syncrude	**34.4**	34.6	35.2
Total	**359.2**	339.3	318.2

(1) Bitumen from Oil Sands Base operations is upgraded, while bitumen from In Situ operations is upgraded or sold directly to customers. Yields of SCO and diesel from Suncor's upgrading processes are approximately 79% of bitumen feedstock input. See also the Bitumen from Operations table presented below.

The Oil Sands segment achieved record production with an average of 359,200 bbls/d in 2012, increasing from 339,300 bbls/d in 2011. The increase in Oil Sands production was primarily due to the ramp up of production from Firebag.

Production of upgraded product (sweet SCO, sour SCO and diesel) averaged 276,700 bbls/d in 2012, compared to 279,700 bbls/d in 2011. Production in 2012 was impacted by planned maintenance on various coker units and hydrotreating units in Upgrader 1 and 2, as well as unplanned maintenance relating to primary and secondary upgrading at Upgrader 2. Production in 2011 was impacted by the completion of a six-week planned maintenance event at Upgrader 2 facilities and unplanned maintenance at the Upgrader 1 hydrogen plant. Although the scope of planned maintenance completed in 2012 was much smaller, the unplanned maintenance activities constrained production in the year. Non-upgraded bitumen production averaged 48,100 bbls/d in 2012, compared to 25,000 bbls/d in 2011, and increased due primarily to higher production from Firebag.

Suncor's share of Syncrude production and sales averaged 34,400 bbls/d in 2012, compared to 34,600 bbls/d in 2011. Production was impacted by a similar amount in 2012 and 2011 due to unplanned maintenance.

Bitumen from Operations

Year ended December 31	**2012**	2011	2010
Oil Sands Base			
Production (mbbls/d)	**266.2**	287.1	266.2
Ore mined (thousands of tonnes per day)	**412.3**	441.1	391.9
Bitumen ore grade quality (bbls/tonne)	**0.65**	0.65	0.68
In Situ bitumen production (mbbls/d)			
Firebag	**104.0**	59.5	53.6
MacKay River	**27.0**	30.0	31.5
Total In Situ production	**131.0**	89.5	85.1
In Situ steam-to-oil ratio			
Firebag	**3.4**	3.6	3.2
MacKay River	**2.4**	2.2	2.4

Bitumen from Oil Sands Base operations averaged 266,200 bbls/d in 2012, compared to 287,100 bbls/d in 2011. The decline in bitumen production was due primarily to reduced mining activity in 2012 to coincide with lower upgrader availability that was constrained by maintenance activities. For the majority of the year, the company had been mining through a lower ore grade quality of the Millennium mining area; however, by the fourth quarter of 2012, Suncor had worked through the area of lower bitumen ore grade quality, as planned.

Bitumen from In Situ operations averaged 131,000 bbls/d in 2012, increasing from 89,500 bbls/d in 2011.

- Production from Firebag averaged 104,000 bbls/d in 2012 compared to 59,500 bbls/d in 2011. Stage 3 central processing facilities reached design rates approximately one year after achieving first oil in August 2011, while Stage 4 cogeneration units and central processing facilities were commissioned ahead of schedule, with the central processing facility operating at 10% capacity throughout the fourth quarter of 2012. Production from Firebag is expected to reach production capacity of 180,000 bbls/d over the next year.

- Production from MacKay River averaged 27,000 bbls/d in 2012, compared to 30,000 bbls/d in 2011, and decreased primarily due to increased planned maintenance activities in 2012 and natural declines in older wells. In order to maintain production levels, the company began steaming wells on a new pad in December 2012, with first oil from these wells anticipated in the first quarter of 2013.

Sales Volumes and Mix

Year ended December 31	**2012**	2011	2010
Oil Sands sales volumes (mbbls/d)			
Sweet SCO	**93.8**	85.5	82.3
Diesel	**24.5**	24.3	20.4
Sour SCO	**161.1**	170.6	145.2
Upgraded Product (SCO)	**279.4**	280.4	247.9
Non-upgraded bitumen	**44.5**	24.0	31.4
	323.9	304.4	279.3

Sales volumes for Oil Sands operations increased to 323,900 bbls/d in 2012, compared to 304,400 bbls/d in 2011.

- Sales volumes of sweet product (sweet SCO and diesel) increased in 2012, compared to 2011. The start-up of operations for the MNU in the third quarter of 2012 enabled Suncor to maintain a more profitable SCO sales mix during maintenance at Upgrader 2 in 2012. In 2011, sales of sweet product were impacted by the planned maintenance event at Upgrader 2 and unplanned maintenance at the Upgrader 1 hydrogen plant.

- Sales volumes of non-upgraded bitumen increased in 2012, compared to 2011, mainly due to the incremental Firebag volumes in 2012 resulting in higher non-upgraded bitumen production from Firebag.

Price Realizations

Year ended December 31 Net of transportation costs, but before royalties ($/bbl)	**2012**	2011	2010
Oil Sands			
Sweet SCO and diesel	**96.95**	103.95	74.71
Sour SCO and non-upgraded bitumen	**72.93**	80.17	66.60
Crude sales basket (all products)	**81.69**	88.74	69.58
Crude sales basket, relative to WTI	**(12.44)**	(5.35)	(12.33)
Oil Sands Ventures			
Syncrude – Sweet SCO	**92.69**	101.80	80.93
Syncrude, relative to WTI	**(1.50)**	7.71	(0.98)

Average price realizations for Oil Sands operations decreased to $81.69/bbl in 2012 from $88.74/bbl in 2011, due to a higher proportion of non-upgraded bitumen sales in 2012, combined with less favourable price differentials. Although the average price for WTI remained relatively constant from 2011, the average premium for sweet SCO relative to WTI was lower by approximately $6/bbl. Sour SCO and non-upgraded bitumen prices reflected the widening discount for WCS relative to WTI. As a result, the average price realization for Oil Sands operations relative to WTI was WTI less $12.44/bbl in 2012, compared with WTI less $5.35/bbl in 2011.

Suncor's average price realization for Syncrude sales in 2012 was $92.69/bbl, compared to $101.80/bbl in 2011, primarily due to less favourable differentials between sweet SCO and WTI in 2012.

Royalties

Royalties were lower in 2012 relative to 2011 due to lower benchmark prices for WCS that influenced the company's regulated bitumen valuation methodology used to determine royalties for mining properties. Higher eligible capital costs deductions at Syncrude for large sustaining capital expenditures also contributed to lower royalties in 2012.

Inventory

The Inventory variance factor decreased operating earnings due to a large build in inventory at the end of 2012, resulting from increased non-upgraded bitumen production and line fill required for assets that were brought into service in late 2012, including the Wood Buffalo pipeline and two storage tanks in Hardisty, Alberta.

Expenses and Other Factors

Operating expenses for 2012 were slightly higher than 2011. Factors contributing to the change in operating expenses included:

- Cash operating costs for Oil Sands operations increased slightly to $4.395 billion in 2012 from $4.355 billion in 2011 due to the incremental costs required to operate assets brought into service in the current year, including Firebag Stage 4 central processing facilities and the MNU, partially offset by lower natural gas prices, the net benefit provided by higher power sales and operating efficiencies, including the benefits associated with the North Steepbank mining area.

- Other operating expenses were higher in 2012 than 2011 due primarily to higher share-based compensation expense and higher costs related to remobilizing certain growth projects out of "safe mode" after the economic downturn in late 2008 and early 2009, partially offset by lower costs relating to the reduced scope of start-up activity for Firebag Stage 4, and the receipt of pipeline transportation credits.

- Operating expenses at Syncrude were lower for 2012 than 2011, as a result of lower fuel costs and lower planned maintenance expenditures.

DD&A expense for 2012 was higher than 2011, due to the larger asset base that is the result of commissioning additional Firebag assets, the TRO $_{TM}$ project, the MNU, the North Steepbank mining area, and the costs capitalized as part of planned maintenance events.

Cash Operating Costs Reconciliation [1][2]

Year ended December 31	**2012**	2011	2010
Operating, selling and general expense (OS&G)	**5 375**	5 169	4 537
Syncrude OS&G	**(513)**	(529)	(473)
Non-production costs [3]	**(338)**	(275)	(305)
Other [4]	**(129)**	(10)	32
Oil Sands cash operating costs ($ millions)	**4 395**	4 355	3 791
Oil sands cash operating costs ($/bbl)	**37.05**	39.05	36.70

(1) Cash operating costs and cash operating costs per barrel are non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this document.

(2) Effective as of the first quarter of 2012, the calculation of cash operating costs has been revised to better reflect the ongoing cash costs of production, and prior period figures have been redetermined. See the Non-GAAP Financial Measures Advisory section of this document.

(3) Significant non-production costs include, but are not limited to, share-based compensation adjustments, costs related to the remobilization or deferral of growth projects, research, the expense recorded as part of a non-monetary arrangement involving a third-party processor and feedstock costs for natural gas used to create hydrogen for secondary upgrading processes.

(4) Other includes the impacts of changes in inventory valuation and operating revenues associated with excess power from cogeneration units.

Oil Sands cash operating costs per barrel decreased in 2012, averaging $37.05/bbl, compared to $39.05/bbl in 2011 due to higher production volumes while total cash operating costs increased slightly. Total cash operating costs in 2012 were impacted by the incremental costs required to operate assets brought into service in the current year, including Firebag Stage 4 central processing facilities and the MNU, partially offset by lower natural gas prices, the net benefit provided by higher power sales and operating efficiencies, including the benefits associated with the North Steepbank mining area.

Voyageur Upgrader Project Impairment

Given the challenging economic outlook for the Voyageur upgrader project, the company performed an impairment test in the fourth quarter of 2012. Based on an assessment of expected future net cash flows, the company recorded an after-tax impairment charge of $1.487 billion, after which the company's carrying value for net assets relating to the Voyageur upgrader project as at December 31, 2012 was approximately $345 million.

Planned Maintenance Events

The company plans to commence refurbishing the Upgrader 1 hydrogen plant late in the first quarter of 2013, which is expected to be offline for approximately 14 weeks. The decrease in sweet SCO production during this outage is expected to be partially offset by the additional hydrotreating capacity from the MNU.

The company has scheduled a planned maintenance event for its Upgrader 1 facility in the second quarter of 2013. The event is scheduled for approximately seven weeks, during which time there will be no production from Upgrader 1. Within this outage, the company anticipates completing planned maintenance at one of the Firebag central processing facilities.

Planned maintenance is also scheduled in the third quarter of 2013 for the company's Upgrader 2 facilities, which is anticipated to have an impact on SCO production.

The production impact of the maintenance discussed above has been reflected in the company's 2013 guidance.

Results for 2011 compared with 2010

Oil Sands net earnings for 2011 were $2.603 billion, compared to $1.520 billion in 2010. Net earnings in 2011

included an after-tax loss on the partial disposition of interests in the Voyageur upgrader and Fort Hills mining projects. Net earnings for 2010 included after-tax gains of $233 million for the change in fair value of commodity derivatives used for risk management and $51 million for a recovery of royalties pertaining to a change in Suncor's BVM, partially offset by after-tax write-offs of $143 million primarily associated with equipment for an alternative mining and extraction process that was discontinued.

Operating earnings for 2011 were $2.737 billion, compared to $1.379 billion in 2010, and increased primarily due to higher average price realizations and higher production volumes, offset by higher operating expenses and DD&A. Production volumes were lower during the first half of 2010 due mainly to the impacts of the two upgrader fires. Operating expenses were higher in 2011, due mainly to costs associated with the start of operations for Firebag 3 and with unplanned maintenance on secondary upgrading units at Upgrader 1. DD&A was higher, due mainly to commissioning assets such as Firebag 3 and the 2011 planned maintenance event.

Cash flow from operations for 2011 was $4.572 billion, compared to $2.777 billion in 2010, due primarily to higher margins, which were driven by higher price realizations and higher production volumes.

During the first quarter of 2011, Suncor completed transactions with Total E&P, which brought Total E&P into the Voyageur upgrader project and increased Total E&P's working interest in the Fort Hills oil sands mining project, and which brought Suncor into the Joslyn oil sands mining project. In consideration for Total E&P acquiring a 49% interest in the Voyageur upgrader project, an additional 19.2% interest in the Fort Hills project, rights to certain knowledge and technology licences, and Total E&P assuming its share of capital expenditures subsequent to the transaction effective date of January 1, 2011, Suncor received $2.662 billion from Total E&P, net of transaction costs. Suncor recorded an after-tax loss of $99 million on the partial disposition of its assets, which included a reduction of $267 million to goodwill that the company allocated to its disposed interests. In consideration for Suncor acquiring a 36.75% interest in Joslyn and assuming its share of capital expenditures subsequent to the effective date, Suncor paid Total E&P $842 million.

EXPLORATION AND PRODUCTION

Strategy and Operational Update

Suncor's Exploration and Production operations are mainly comprised of conventional upstream assets. The Exploration and Production segment continued to generate significant cash flow for Suncor, and remains an important source of funding for future growth. Profitability was also realized through high price realization as over 70% of 2012 production from this segment received prices based on Brent crude, which traded at a significant premium to WTI.

As noted, 2012 results for the Exploration and Production segment were highlighted by planned maintenance activities at all offshore facilities, including the replacement of the floating production, storage and offloading vessels (FPSO) water injection swivel and subsea infrastructure at Terra Nova and the repair of the FPSO propulsion system and other maintenance at White Rose. Production levels in Libya were strong following the restart of production after the regime change in 2011. Suncor is encouraged by this progress and is working to restart exploration activities in 2013.

The year was not without its challenges. Operations in Syria remained suspended throughout 2012 as a result of political unrest and international sanctions against that country. North American natural gas prices were very low throughout the year, resulting in the shut in of production in certain areas in Western Canada.

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 those opportunities that meets its financial objectives.

Growth from the Exploration and Production segment is an important focus for Suncor, with approximately half of Suncor's 2013 growth capital targeted towards advancing projects within the segment. The company and co-owners announced sanction of the Hebron project offshore Newfoundland and Labrador in the fourth quarter of 2012. The estimated gross oil production capacity for Hebron is 150,000 bbls/d with initial production estimated late in 2017.

The company and co-owners of the Golden Eagle project in the UK sector of the North Sea continued to progress development in 2012, with initial production estimated in late 2014 or early 2015.

The company also plans to leverage and extend the productive life of existing offshore infrastructure, with

drilling activities in areas adjacent to producing fields, such as the HSEU, the White Rose Extensions, and the Northern Terrace area for Buzzard.

Longer term, there is potential for new prospects offshore Norway, where the company is increasingly acting as operator for its growing exploration portfolio, and in the mature U.K. North Sea and East Coast Canada basins.

Financial Highlights

Year ended December 31 ($ millions)	**2012**	2011	2010
Gross revenues	**6 476**	6 784	7 043
Less: Royalties	**(1 631)**	(1 472)	(1 377)
Operating revenues, net of royalties	**4 845**	5 312	5 666
Net earnings	**138**	306	1 938
Operating earnings [1]			
East Coast Canada	**422**	694	407
International	**538**	708	793
North America Onshore	**(110)**	(44)	(7)
	850	1 358	1 193
Cash flow from operations [1]	**2 227**	2 846	3 325

(1) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Exploration and Production net earnings for 2012 were $138 million, compared to $306 million for 2011. Net earnings for 2012 included total impairments (net of reversals), write-offs and provisions of $689 million. The company recorded after-tax impairment (net of reversals) and write-offs of $517 million for assets in Syria, after-tax impairment charges of $65 million to reflect future development uncertainty relating to certain exploration assets in East Coast Canada and North America Onshore, and an after-tax impairment charge of $63 million for certain North America Onshore properties due to a decline in price forecasts. In addition, the company recorded an after-tax provision of $44 million in North America Onshore relating to future commitments for unutilized pipeline capacity. Net earnings also included a deferred income tax charge of $23 million related to an income tax rate change.

Net earnings for 2011 included after-tax impairments (net of reversals) of $571 million comprised of an after-tax impairment (net of reversals) of $503 million for assets in Libya as a result of the shut in of production, and $68 million against certain North America Onshore properties due to decreasing price forecasts. Net earnings in 2011 were also impacted by a deferred income tax charge of $442 million pertaining to an increase in the U.K. statutory income tax rate, an after-tax provision of $31 million pertaining to a royalty dispute covering a period from before the merger, and after-tax losses on the disposal of non-core assets of $8 million.

For 2012, operating earnings for East Coast Canada were $422 million, compared to $694 million for 2011, and were lower due primarily to planned off-station maintenance programs at Terra Nova, White Rose and Hibernia that decreased production. Operating earnings for International were $538 million for 2012, compared to $708 million for 2011, and were lower primarily due to the suspension of operations in Syria, higher income tax expense in the UK due to a statutory income tax rate increase, and higher exploration and well write-offs, partially offset by the resumption of operations in Libya and higher price realizations in 2012. The operating loss for North America Onshore was $110 million for 2012, compared with an operating loss of $44 million for 2011, due to lower natural gas prices and production volumes.

Cash flow from operations was $2.227 billion in 2012, compared to $2.846 billion in 2011, and decreased primarily due to the same factors that affected operating earnings.

Operating Earnings

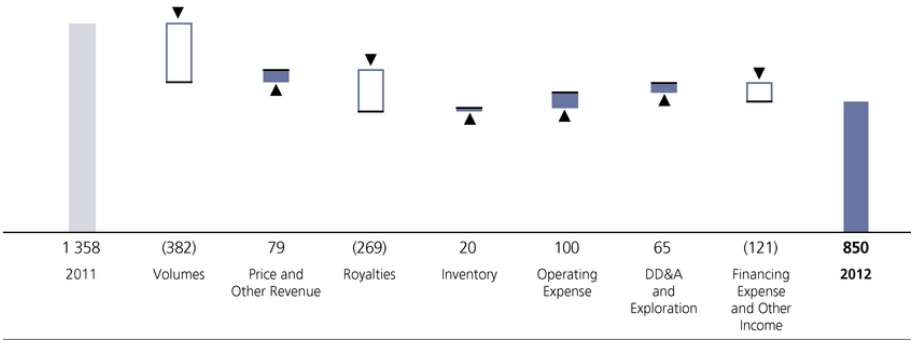
Operating Earnings Reconciliation

Year ended December 31 ($ millions)	**2012**	2011	2010
Net earnings as reported	**138**	306	1 938
Impairments (net of reversals), write-offs and provisions	**689**	571	163
Impact of income tax rate adjustments on deferred income taxes	**23**	442	—
Adjustments to provisions for assets acquired through the merger	**—**	31	84
Loss (gain) on significant disposals	**—**	8	(826)
Redetermination of working interest in Terra Nova	**—**	—	(166)
Operating earnings (1)	**850**	1 358	1 193

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Operating Earnings(1)

($ millions)



(1) For an explanation of the construction of this bridge analysis, see the Non-GAAP Financial Measures Advisory section of this MD&A.

Production Volumes

Year ended December 31	**2012**	2011	2010
Production volumes (mboe/d)	**189.9**	206.7	296.9
East Coast Canada (mbbls/d)	**46.5**	65.6	68.6
International (mboe/d)	**89.5**	76.4	132.5
North America Onshore (mmcfe/d)	**323**	388	575
Production Mix (liquids/gas) (%)	**74/26**	64/36	63/37
East Coast Canada	**100/0**	100/0	100/0
International	**99/1**	82/18	87/13
North America Onshore	**10/90**	8/92	9/91

East Coast Canada production averaged 46,500 bbls/d in 2012, compared to 65,600 bbls/d in 2011.

- Production from Terra Nova averaged 8,800 bbls/d in 2012, compared to 16,200 bbls/d in 2011. Production was shut in for 27 weeks during 2012 for a dockside maintenance program to replace the FPSO water injection swivel and complete other routine planned maintenance. Suncor also used this outage to perform work on subsea infrastructure to help mitigate hydrogen sulphide (H_2S) issues. Following the dockside maintenance program, production from the largest drill centre resumed in December, while production from a second drill centre was delayed until February 2013. The third drill centre is expected to be commissioned in the third quarter of 2013 when faulty flow lines can be replaced. Despite the impact on production from not commissioning the third drill centre, the company expects to meet 2013 guidance in respect of East Coast Canada production.

- Production from White Rose averaged 11,600 bbls/d in 2012, compared to 18,500 bbls/d in 2011. Production was shut in for 15 weeks during 2012 for an off-station maintenance program to repair the FPSO propulsion system, in addition to other routine planned maintenance activities.

- Production from Hibernia averaged 26,100 bbls/d in 2012, compared to 30,900 bbls/d in 2011. Production was shut in for four weeks for planned maintenance. Natural declines from older wells were partially offset by production increases from ongoing development drilling.

International production averaged 89,500 boe/d in 2012, compared to 76,400 boe/d in 2011.

- Production from the North Sea averaged 48,000 boe/d in 2012, compared to 46,700 boe/d in 2011. Higher production from Buzzard reflected improved reliability during 2012. In 2011, production from Buzzard was constrained due to replacement of the gas compression cooling system, downtime and capacity constraints on a third-party export pipeline, and other outages that coincided with the commissioning of the fourth platform. Production in 2011 included 3,800 boe/d from non-core U.K. assets that were divested in the first quarter of 2011.

- Production from Libya averaged 41,500 bbls/d in 2012, compared to 12,100 bbls/d in 2011. Production from Libya was suspended throughout much of 2011 due to the outbreak of political unrest and international sanctions. Subsequent to the government regime change and the lifting of sanctions, production was restarted later in the year and had resumed in all major fields by the first quarter of 2012.

- In December 2011, the company declared force majeure under its contractual obligations in Syria due to political unrest and international sanctions affecting that country. As a result, the company recorded no production from Syria for 2012. Production from Syria averaged 17,600 boe/d in 2011.

North America Onshore production averaged 323 mmcfe/d in 2012, compared to 388 mmcfe/d in 2011.

- During the first half of 2012, the shut in of production from certain fields in southwest Alberta and northeast B.C., in response to low natural gas prices and the closure of a natural gas facility, contributed production of approximately 25 mmcfe/d in 2011.

- Throughout 2011, the company divested non-core assets that contributed production of approximately 14 mmcfe/d in 2011.

- Production from remaining properties decreased in 2012 primarily due to natural declines.

Price Realizations

Year ended December 31 Net of transportation costs, but before royalties	**2012**	2011	2010
Exploration and Production ($/boe)	**84.05**	79.95	61.06
East Coast Canada ($/bbl)	**112.15**	108.42	80.20
International ($/boe)	**108.22**	100.89	74.92
North America Onshore ($/mcfe)	**3.28**	4.39	4.70

In 2012, average price realizations for crude oil from East Coast Canada were higher than 2011. Although the price for Brent crude for 2012 was consistent with the prior year, price realizations in East Coast Canada increased to $112.15/bbl in 2012 compared to $108.42/bbl in 2011, primarily due to higher production in the first quarter of 2012 when the price for Brent crude was at its highest for the year.

For International, average price realizations were higher in 2012 due to the mix impact of adding higher priced crude oil production from Libya and removing natural gas production from Syria.

Average price realizations for North America Onshore were lower due primarily to lower benchmark prices for natural gas.

Royalties

Royalties were higher in 2012, compared with 2011, due primarily to higher production from Libya, where effective royalty rates are substantially higher than those for other Exploration and Production assets. This increase was partially offset by lower royalties from less production in East Coast Canada and North America Onshore in comparison to 2011, and the suspension of operations in Syria in 2012.

Expenses and Other Factors

Operating expenses were lower in 2012 than in 2011 due to lower production volumes in East Coast Canada, lower production in North America Onshore and the suspension of operations in Syria, partially offset by higher incremental expenses associated with planned maintenance in 2012 and the resumption of operations in Libya.

In March 2012, while drilling an exploratory natural gas well in B.C., a fire occurred on a drilling rig. The fire was brought under control in early April, and the well was subsequently capped. Operating expenses associated with the containment and monitoring of this well were approximately $43 million before tax, partially offset by $25 million before tax in partial insurance proceeds received in the fourth quarter of 2012.

DD&A and exploration expenses were lower in 2012 due primarily to less production, partially offset by higher exploration write-offs. The company wrote off $145 million in exploration expenditures ($42 million after-tax) in 2012, primarily associated with a second appraisal well for the Beta discovery and an exploration well for the Cooper prospect.

Financing expense and other income was impacted by a higher effective tax rate in 2012 due to an increase in the statutory tax rate in the U.K. and the impact of reinvesting proceeds from U.K. asset disposals in 2011.

Impairment and Write-Off of Syrian Assets

As a result of the political unrest that began in Syria in the latter half of 2011 and ensuing international sanctions, Suncor declared force majeure under its contractual obligations and suspended operations in the country in December 2011. In the second quarter of 2012, Suncor estimated the net recoverable value of its assets in Syria based on an assessment of expected future net cash flows over a range of possible outcomes. Based on this assessment, the company recorded impairment charges of $604 million against property, plant and equipment. In the same quarter, the company recorded a further write-down of $67 million against remaining accounts receivable and a write-off of $23 million for other current assets.

In the fourth quarter of 2012, the company received risk mitigation proceeds of $300 million pertaining to the suspension of the company's operations in Syria. A portion, or all, of these proceeds may be repayable if operations in Syria resume. As a result, the proceeds were not recorded in earnings but rather as a provision. Suncor re-estimated the net recoverable value of its assets in Syria at the end of 2012, extending the future potential dates for the resumption of operations further into the future and including repayment of risk mitigation proceeds in scenarios where operations resumed. As a result of the changes, the company reversed $177 million of the impairment charges recorded earlier in the year.

Impairments (net of reversals) and write-offs in 2012 were $517 million, net of income taxes of $nil. After impairments (net of reversals) and write-offs, the carrying value of Suncor's property, plant and equipment in Syria net of the risk mitigation provision as at December 31, 2012 was approximately $130 million.

Planned Maintenance Events

Routine annual planned maintenance has been scheduled for Terra Nova, White Rose and Buzzard in the second and third quarters of 2013.

The production impact of this maintenance has been reflected in the company's 2013 guidance.

Results for 2011 compared with 2010

Exploration and Production net earnings for 2011 were $306 billion, compared to $1.938 million in 2010. Net earnings in 2010 included after-tax gains of $826 million on the disposal of non-core assets, an after-tax gain of $166 million for the redetermination of Suncor's working interest in Terra Nova, after-tax impairment charges of $111 million on certain North America Onshore assets mainly due to lower natural gas prices, an after-tax provision of $84 million related to losses on unfavourable natural gas pipeline commitments, and after-tax impairment charges of $52 million on non-core U.K. assets that were divested.

Operating earnings for 2011 were $1.358 billion, compared to $1.193 billion for 2010, and increased primarily due to higher price realizations and lower operating expenses and DD&A, partially offset by lower production volumes, higher royalties and a higher effective tax rate on U.K. earnings.

Cash flow from operations was $2.846 billion for 2011, compared to $3.325 billion for 2010. The decrease in cash flow from operations relative to the increase in operating earnings was due primarily to lower production from assets in 2011 that contributed relatively more to cash flow from operations than operating earnings for 2010. In addition, cash flow from operations in 2010 included the gain from the settlement pertaining to the redetermination of working interests in Terra Nova.

REFINING AND MARKETING

Strategy and Operational Update

Results from 2012 for the Refining and Marketing segment were strong, reinforcing the value of an integrated business model to Suncor's overall strategy. The Refining and Marketing segment translated lower price realizations impacting the Oil Sands to strong refining margins. The segments financial performance was supported by 100% utilization rates at the company's Western North America refineries.

In 2012, the company's inland refinery network (Edmonton, Sarnia and Commerce City) was again able to

capture the favourable WTI to Brent and Canadian crude differentials through strong refining margins. The integration of these refineries with crude output from Suncor's Oil Sands segment also resulted in lower feedstock costs. Suncor's focus on reliability and continuous improvements enabled the company to sustain high throughput levels, which resulted in nameplate capacity increases for the Sarnia and Commerce City refineries, effective January 1, 2012, and the Edmonton refinery, effective January 1, 2013.

In 2013, Suncor will continue to focus on optimizing overall integration. As bitumen production exceeds upgrading capacity in the Oil Sands, the company continues to explore opportunities to capture the potential value in the refining operations. In 2013, the company will focus on bringing the Montreal refinery into the inland refining network, and plans to transport western Canadian crudes via rail to the refinery.

Suncor's Petro-Canada branded outlets continue to be a leading retailer by market share in major urban areas of Canada. Increased competition and fluctuating demand in key retail markets are expected to be offset by growth in wholesale channels. Refining and Marketing will continue to leverage the strong brand to increase non-petroleum revenues through the company's network of convenience stores and car washes, and expand the lubricants product offering.

Financial Highlights

Year ended December 31 ($ millions)	**2012**	2011	2010
Operating revenues	**26 321**	25 713	20 860
Net earnings	**2 129**	1 726	819
Operating earnings [1]			
Refining and Product Supply	**1 869**	1 413	532
Marketing	**275**	313	264
	2 144	1 726	796
Cash flow from operations [1]	**3 150**	2 574	1 538

(1) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Refining and Marketing recorded net earnings of $2.129 billion and operating earnings of $2.144 billion in 2012, compared with net and operating earnings of $1.726 billion in 2011.

Refining and Product Supply operations contributed $1.869 billion to operating earnings in 2012, a significant increase compared with 2011, primarily due to higher refining margins from lower costs for inland heavy, synthetic, and conventional crude feedstock, higher benchmark refining margins, and higher refinery utilization, slightly offset by the negative impacts of a decreasing crude price environment, whereby inventories produced during periods of higher feedstock costs were sold and replaced with inventories purchased at relatively lower feedstock costs. Marketing operations contributed $275 million to operating earnings in 2012, which was lower than in 2011, due mainly to lower sales volumes and margins in the retail channel.

Cash flow from operations was $3.150 billion in 2012, compared to $2.574 billion in 2011, and increased primarily due to the same factors that affected operating earnings.

Operating Earnings

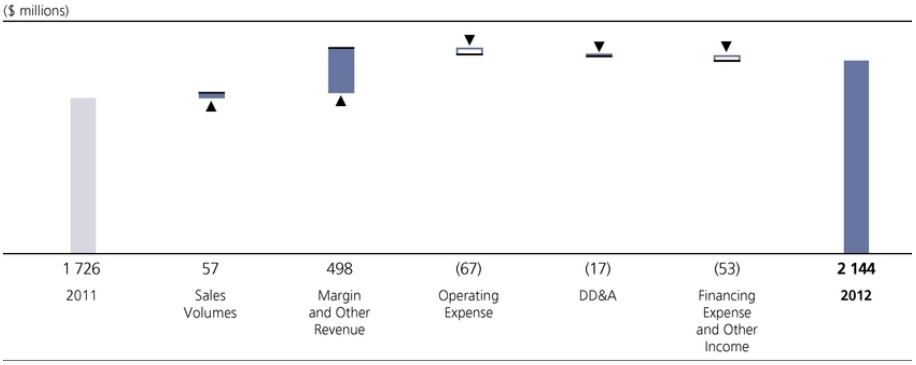
Operating Earnings Reconciliation

Year ended December 31 ($ millions)	**2012**	2011	2010
Net earnings as reported	**2 129**	1 726	819
Impact of income tax rate adjustments on deferred income taxes	**15**	—	—
Adjustments to provisions for assets acquired through the merger	**—**	—	(23)
Operating earnings [1]	**2 144**	1 726	796

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Bridge Analysis of Operating Earnings[1]

($ millions)



(1) For an explanation of the construction of this bridge analysis, see the Non-GAAP Financial Measures Advisory section of this MD&A.

Volumes

Year ended December 31	**2012**	2011	2010
Crude oil processed (thousands of m^3/d)			
Eastern North America	**31.4**	32.0	30.5
Western North America	**37.2**	32.8	34.6
Refinery utilization [1][2] (%)			
Eastern North America	**89**	94	89
Western North America	**100**	91	95
Refined Product Sales (thousands of m^3/d)			
Gasoline	**40.2**	39.7	41.1
Distillate	**31.0**	30.4	30.4
Other	**14.4**	13.0	15.8
	85.6	83.1	87.3

(1) Effective January 1, 2012, the company increased the nameplate capacity of the Montreal refinery from 130,000 bbls/d (20.7 m^3/d) to 137,000 bbls/d (21.8 m^3/d) and the nameplate capacity of the Commerce City refinery from 93,000 bbls/d (14.8 m^3/d) to 98,000 bbls/d (15.6 m^3/d). Prior years' utilization rates have not been recalculated and reflect the lower nameplate capacities. Effective January 1, 2013, the company increased the nameplate capacity of the Edmonton refinery from 135,000 bbls/d (21.5 m^3/d) to 140,000 bbls/d (22.3 m^3/d). Figures above have not been recalculated to reflect the revised nameplate capacity.

(2) Refinery utilization is the amount of crude oil and natural gas plant liquids run through crude distillation units, expressed as a percentage of the capacity of these units.

Total sales of refined petroleum products increased to an average of 85,600 m^3/d in 2012, compared to 83,100 m^3/d in 2011. Suncor was able to meet the higher demands for gasoline and distillate in Western North America through reliability and continuous improvements in the Edmonton refinery. Suncor increased the nameplate capacity of the Edmonton refinery to 140,000 bbls/d from 135,000 bbls/d, effective January 1, 2013. Gasoline and distillate sales in Eastern North America were impacted by weaker demand and increased competition.

Refinery utilization in Eastern North America averaged 89% in 2012, compared to 94% in 2011. Refinery utilization in 2012 was impacted by an unplanned outage of a crude unit at the Sarnia refinery in the first quarter of 2012, a reduction in feedstock availability in the second quarter due to an unplanned Oil Sands upgrader outage, and a scheduled maintenance event at the Sarnia refinery in the fourth quarter of 2012.

Refineries in Western North America ran at full capacity for the majority of 2012, with an average utilization of 100% in 2012, compared to 91% in 2011. The increase over the prior year was the result of a month-long disruption to third-party hydrogen supply and a six-week planned maintenance event in the Edmonton refinery in 2011, while refinery utilization at the Commerce City refinery was also impacted by a five-week planned maintenance event during the second quarter of 2011.

Prices and Margins

For Refining and Product Supply, prices and margins for refined products were higher in 2012 compared to 2011, reflecting lower crude feedstock costs and higher crack spreads, partially offset by the inventory valuation impact of a declining crude price environment.

- Prices for Canadian-based crude feedstock for the company's inland refineries were lower in 2012 due mainly to larger discounts reflecting increased industry supply. Sweet SCO sold at a lower premium relative to WTI compared with 2011 and in some months at discounts relative to WTI, in addition to lower prices for bitumen due to wider light/heavy crude oil differentials.
- The impact on earnings pertaining to the declining crude price environment over 2012 decreased after-tax earnings by approximately $153 million, whereas the impact on earnings pertaining to the rising crude price

environment in 2011 increased after-tax earnings by approximately $230 million.

For Marketing, lower margins in retail were partially offset by higher margins in the wholesale channel.

Expenses and Other Factors

Operating expenses were higher in 2012 than in 2011, due to higher share-based compensation expense, partially offset by lower energy prices for natural gas.

The Financing Expense and Other Income factor was negatively impacted by lower gains on risk management activities in the current year and a gain pertaining to the company's investments in marketing entities.

Planned Maintenance Events

The company has scheduled planned maintenance events at the Edmonton refinery on its heavy sour crude train in the second quarter of 2013, with an expected duration of five weeks, and on its sweet synthetic crude unit in the third quarter of 2013, with an expected duration of two weeks. A six-week planned maintenance event is scheduled at the Sarnia refinery for one of its crude units, beginning the third quarter of 2013.

The impact of this maintenance has been reflected in the company's 2013 guidance.

Results for 2011 compared with 2010

Refining and Marketing net and operating earnings for 2011 were $1.726 billion, compared to net earnings of $819 million and operating earnings of $796 million for 2010. Earnings increased primarily due to higher refining margin and the positive impacts of an increasing crude price environment.

Cash flow from operations for 2011 were $2.574 billion, compared to $1.538 billion for 2010, and increased mainly due to the same factors that affected operating earnings.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

Strategy and Operational Update

The Energy Trading business continued to add value in 2012 by accessing key logistical transportation and storage assets across North America to support planned increases in production capacity. The Energy Trading business supports the company's production by optimizing price realizations, managing inventory levels during unplanned outages at Suncor's facilities and managing the impacts of external market factors, such as pipeline disruptions or outages at refining customers, while generating trading earnings through established strategies. The Energy Trading business continues to evaluate additional pipeline agreements to support planned increases in production capacity.

For Renewable Energy, in 2013, the company will continue to progress the Adelaide and Cedar Point wind projects through the regulatory process. The two projects are expected to add 140 MW of gross installed capacity, increasing the gross installed capacity of Suncor's wind projects by 55%. The focus for the ethanol operations will be to maintain safe and reliable operations and improve plant profitability through technology improvements.

Financial Highlights

Year ended December 31 ($ millions)	**2012**	2011	2010
Net earnings (loss)	**58**	(331)	(448)
Operating earnings (loss) [1]			
Renewable Energy	**57**	72	33
Energy Trading	**147**	149	64
Corporate	**(407)**	(346)	(842)
Group Eliminations	**84**	(22)	11
	(119)	(147)	(734)
Cash flow used in operations [1]	**(39)**	(246)	(984)

(1) Non-GAAP financial measures. Operating earnings are reconciled to net earnings below. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Net earnings for Corporate, Energy Trading and Eliminations for 2012 were $58 million, compared to a net loss of $331 million for 2011. In 2012, the Canadian dollar strengthened in relation to the U.S. dollar, with the exchange rate increasing from 0.98 to 1.01, resulting in an after-tax unrealized foreign exchange gain on

U.S. dollar denominated long-term debt of $157 million. In 2011, the Canadian dollar weakened in relation to the U.S. dollar, with the US$/Cdn$ exchange rate decreasing from 1.01 to 0.98 and resulting in an after-tax unrealized foreign exchange loss on U.S. dollar denominated long-term debt of $161 million. Net earnings for 2012 also included a deferred tax reduction of $20 million related to an income tax rate change.

The operating loss for Corporate, Energy Trading and Eliminations in 2012 was $119 million, compared with an operating loss of $147 million in 2011. Operating earnings are discussed below.

Operating Earnings

Operating Earnings Reconciliation

Year ended December 31 ($ millions)	**2012**	2011	2010
Net earnings (loss) as reported	**58**	(331)	(448)
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(157)**	161	(372)
Impairments and write-offs	**—**	23	—
Impact of income tax rate adjustments on deferred income taxes	**(20)**	—	—
Merger and integration costs	**—**	—	79
Adjustments to provisions for assets acquired through the merger	**—**	—	7
Operating loss [1]	**(119)**	(147)	(734)

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Renewable Energy

Year ended December 31	**2012**	2011	2010
Power generation marketed (gigawatt hours)	**429**	245	174
Ethanol production (thousands of m^3)	**412.5**	381.5	206.0

Suncor's renewable energy assets contributed operating earnings of $57 million in 2012, compared to $72 million in 2011, and decreased primarily due to lower margins on ethanol sales that reflected higher prices for feedstock, partially offset by an increase in total power generation marketed from 245 gigawatt hours in 2011 compared to 429 gigawatt hours in 2012. In 2011, Suncor commissioned two new wind power projects – the 88-MW, 55-turbine Wintering Hills project in southern Alberta and the 20-MW, eight-turbine Kent Breeze project in southwest Ontario.

Energy Trading

Energy Trading activities contributed operating earnings of $147 million in 2012, compared to $149 million in 2011. Energy trading continued to contribute to operating earnings, primarily through its heavy crude trading strategies that purchase heavy crude oil in Alberta and transport it to markets with more favourable prices.

Corporate

Corporate had an operating loss of $407 million in 2012, compared with an operating loss of $346 million in 2011. The increase in operating loss was due to higher share-based compensation expense and higher DD&A due to the start of depreciation on Suncor's system integration initiative over the second half of 2011.

In 2012, the company capitalized 91% of its borrowing costs as part of the cost of major development assets and construction projects, compared to 85% in 2011.

Group Eliminations

Group Eliminations reflect the elimination of profit on crude oil sales from Oil Sands and East Coast Canada to Refining and Marketing. Consolidated profits are only realized when the company determines that the refined products produced from intersegment purchases of crude feedstock have been sold to third parties. In 2012, $84 million of after-tax intersegment profit that was previously eliminated was recognized, compared to an elimination of profit of $22 million in 2011.

Results for 2011 compared with 2010

The net loss for Corporate, Energy Trading and Eliminations for 2011 was $331 million, compared to $448 million in 2010. In 2011, the Canadian dollar weakened in relation to the U.S. dollar, resulting in an after-tax unrealized foreign exchange loss of $161 million.

The operating loss for Corporate, Energy Trading and Eliminations for 2011 was $147 million, compared with an operating loss of $734 million in 2010. The lower operating loss in 2011 primarily related to after-tax claims of $243 million for the two Oil Sands Base upgrader fires paid by the company's captive insurance program in 2010 and an after-tax increase of $255 million in capitalized interest in 2011.

6. FOURTH QUARTER 2012 ANALYSIS

Financial and Operational Highlights

Three months ended December 31 ($ millions, except as noted)	**2012**	2011
Net earnings		
Oil Sands	**(1 040)**	790
Exploration and Production	**148**	284
Refining and Marketing	**448**	307
Corporate, Energy Trading and Eliminations	**(118)**	46
Total	**(562)**	1 427
Operating earnings (loss) [1]		
Oil Sands	**447**	835
Exploration and Production	**143**	372
Refining and Marketing	**448**	307
Corporate, Energy Trading and Eliminations	**(38)**	(87)
Total	**1 000**	1 427
Cash flow from (used in) operations [1]		
Oil Sands	**1 090**	1 417
Exploration and Production	**529**	780
Refining and Marketing	**641**	534
Corporate, Energy Trading and Eliminations	**(25)**	(81)
Total	**2 235**	2 650
Production volumes (mboe/d)		
Oil Sands	**378.7**	356.8
Exploration and Production	**177.8**	219.7
Total	**556.5**	576.5

(1) Non-GAAP financial measures. Operating earnings and cash flow from operations are reconciled below. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Segment Analysis

Oil Sands

The net loss for the Oil Sands segment was $1.040 billion for the fourth quarter of 2012, compared with net earnings of $790 million for the fourth quarter of 2011. The net loss in the fourth quarter of 2012 included an after-tax impairment charge of $1.487 billion against the Voyageur upgrader project. Oil Sands operating earnings for the fourth quarter of 2012 were $447 million, compared to $835 million for the fourth quarter of 2011. The decrease in operating earnings for Oil Sands operations, compared with the fourth quarter of 2011, was due primarily to lower average price realizations, lower overall margins due to product mix, and higher DD&A, partially offset by lower royalties. Cash flow from operations for the Oil Sands segment for the fourth quarter of 2012 was $1.090 billion, compared to $1.417 billion for the fourth quarter of 2011, and decreased mainly due to lower average price realizations and lower overall margins due to product mix.

Production volumes for Oil Sands operations averaged 342,800 bbls/d for the fourth quarter of 2012, compared to 326,500 bbls/d for the fourth quarter of 2011, and increased primarily due to the ongoing ramp up of production from Firebag. Production of upgraded product decreased to 281,100 bbls/d in the fourth quarter of 2012 from 310,100 bbls/d in the fourth quarter of 2011, primarily due to maintenance at upgrading facilities. Suncor's share of Syncrude production and sales increased to 35,900 bbls/d in the fourth quarter of 2012 from 30,300 bbls/d in the fourth quarter of 2011, due primarily to unplanned maintenance associated with a coker and hydrogen plant in the fourth quarter of 2011.

Exploration and Production

Exploration and Production net earnings were $148 million for the fourth quarter of 2012, compared to $284 million for the fourth quarter of 2011. The company reversed after-tax impairment charges of $177 million against assets in Syria. This reversal was partially offset by after-tax impairment charges of $65 million to reflect future development uncertainty relating to certain exploration assets in East Coast Canada and North America Onshore and an after-tax impairment charge of $63 million for certain North America Onshore properties due to a decline in price forecasts. In addition, the company recorded an after-tax provision of $44 million in North America Onshore relating to future commitments for unutilized pipeline capacity.

Exploration and Production operating earnings were $143 million for the fourth quarter of 2012, compared to $372 million for the fourth quarter of 2011. The decrease was due primarily to planned maintenance at Buzzard and Terra Nova, production declines in North America Onshore, the suspension of operations in Syria, partially offset by the receipt of insurance proceeds for the March 2012 drilling rig fire.

Cash flow from operations for Exploration and Production was $529 million for the fourth quarter of 2012, compared to $780 million for the fourth quarter of 2011. Cash flow from operations decreased due primarily to the same factors that decreased operating earnings.

Production volumes were 177.8 mboe/d in the fourth quarter of 2012, compared to 219.7 mboe/d in the fourth quarter of 2011. The decrease in production volumes was due mainly to planned maintenance programs at Terra Nova and Buzzard, and the suspension of operations in Syria, partially offset by higher production in Libya.

Refining and Marketing

Refining and Marketing net and operating earnings were $448 million for the fourth quarter of 2012, compared with net and operating earnings of $307 million for the fourth quarter of 2011. The increase was due to high refining margins resulting from lower costs for feedstock, higher refined products sales and higher refinery utilization.

Refining and Marketing cash flow from operations was $641 million for the fourth quarter of 2012, compared to $534 million for the fourth quarter of 2011, and increased primarily due to the same factors affecting operating earnings.

Refined product sales averaged 87,000 m^3/d in the fourth quarter of 2012, increasing from 81,600 m^3/d in the fourth quarter of 2011, due primarily to a disruption of third-party hydrogen supply to the Edmonton refinery in the fourth quarter of 2011, and strong demand for distillate in the fourth quarter of 2012.

Corporate, Energy Trading and Eliminations

The net loss for Corporate, Energy Trading and Eliminations for the fourth quarter of 2012 was $118 million, compared to net earnings of $46 million for the fourth quarter of 2011. In the fourth quarter of 2012, the Canadian dollar weakened in relation to the U.S. dollar, resulting in an after-tax unrealized foreign exchange loss on U.S. dollar denominated long-term debt of $80 million. In the fourth quarter of 2011, the Canadian dollar strengthened in relation to the U.S. dollar.

The operating loss for Corporate, Energy Trading and Eliminations for the fourth quarter of 2012 was $38 million, compared to an operating loss of $87 million for the fourth quarter of 2011. The decrease in operating loss was due to the net recognition of $43 million of after-tax intersegment profit that was recognized as the related product had been sold to third parties. In the fourth quarter of 2011, the company eliminated $4 million after-tax of intersegment profit.

Operating Earnings [1]

Three months ended December 31 ($ millions)	Oil Sands 2012	Oil Sands 2011	Exploration and Production 2012	Exploration and Production 2011	Refining and Marketing 2012	Refining and Marketing 2011	Corporate, Energy Trading and Eliminations 2012	Corporate, Energy Trading and Eliminations 2011	Total 2012	Total 2011
Net (loss) earnings as reported	**(1 040)**	790	**148**	284	**448**	307	**(118)**	46	**(562)**	1 427
Unrealized foreign exchange gain (loss) on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**80**	(156)	**80**	(156)
Impairments (net of reversals), and write-offs	**1 487**	35	**(5)**	57	**—**	—	**—**	23	**1 482**	115
Loss on significant disposals	**—**	10	**—**	—	**—**	—	**—**	—	**—**	10
Adjustments to provisions for assets acquired through the merger	**—**	—	**—**	31	**—**	—	**—**	—	**—**	31
Operating earnings (loss)	**447**	835	**143**	372	**448**	307	**(38)**	(87)	**1 000**	1 427

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

Cash flow from Operations [1]

Three months ended December 31 ($ millions)	Oil Sands 2012	Oil Sands 2011	Exploration and Production 2012	Exploration and Production 2011	Refining and Marketing 2012	Refining and Marketing 2011	Corporate, Energy Trading and Eliminations 2012	Corporate, Energy Trading and Eliminations 2011	Total 2012	Total 2011
Net (loss) earnings	**(1 040)**	790	**148**	284	**448**	307	**(118)**	46	**(562)**	1 427
Adjustments for:										
Depreciation, depletion, amortization and impairment	**2 552**	392	**300**	474	**128**	118	**35**	39	**3 015**	1 023
Deferred income taxes	**(357)**	270	**2**	(30)	**68**	92	**(35)**	(10)	**(322)**	322
Accretion of liabilities	**26**	18	**15**	16	**1**	1	**3**	—	**45**	35
Unrealized foreign exchange gain (loss) on U.S. dollar denominated long-term debt	**—**	—	**—**	—	**—**	—	**91**	(179)	**91**	(179)
Change in fair value of derivative contracts	**—**	—	**1**	—	**(1)**	17	**(20)**	34	**(20)**	51
Loss (gain) on disposal of assets	**—**	16	**—**	(9)	**(5)**	(5)	**—**	—	**(5)**	2
Share-based compensation	**17**	31	**3**	8	**10**	19	**13**	21	**43**	79
Exploration expenses	**—**	—	**21**	—	**—**	—	**—**	—	**21**	—
Settlement of decommissioning and restoration liabilities	**(70)**	(113)	**(10)**	(6)	**(8)**	(11)	**—**	—	**(88)**	(130)
Other	**(38)**	13	**49**	43	**—**	(4)	**6**	(32)	**17**	20
Cash flow from (used in) operations	**1 090**	1 417	**529**	780	**641**	534	**(25)**	(81)	**2 235**	2 650
Decrease (increase) in non-cash working capital	**35**	(47)	**(117)**	9	**(497)**	587	**(481)**	(396)	**(1 060)**	153
Cash flow provided by (used in) operating activities	**1 125**	1 370	**412**	789	**144**	1 121	**(506)**	(477)	**1 175**	2 803

(1) Non-GAAP financial measure. See the Non-GAAP Financial Measures Advisory section of this MD&A.

7. QUARTERLY FINANCIAL DATA

Financial Summary

Three months ended ($ millions, unless otherwise noted)	**Dec 31 2012**	Sept 30 2012	June 30 2012	Mar 31 2012	Dec 31 2011	Sept 30 2011	June 30 2011	Mar 31 2011
Total production (mboe/d)	**556.5**	535.3	542.4	562.3	576.5	546.0	460.0	601.3
Oil Sands	**378.7**	378.9	337.8	341.1	356.8	362.5	277.2	360.6
Exploration and Production	**177.8**	156.4	204.6	221.2	219.7	183.5	182.8	240.7
Revenues and other income								
Operating revenues, net of royalties [1]	**9 444**	9 512	9 599	9 653	9 906	10 235	9 255	8 943
Other income	**91**	89	123	105	60	184	77	132
	9 535	9 601	9 722	9 758	9 966	10 419	9 332	9 075
Net (loss) earnings	**(562)**	1 555	333	1 457	1 427	1 287	562	1 028
per common share – basic (dollars)	**(0.37)**	1.01	0.21	0.93	0.91	0.82	0.36	0.65
per common share – diluted (dollars)	**(0.37)**	1.01	0.20	0.93	0.91	0.76	0.31	0.65
Operating earnings [2]	**1 000**	1 303	1 258	1 329	1 427	1 789	980	1 478
per common share – basic (dollars)	**0.65**	0.85	0.81	0.85	0.91	1.14	0.62	0.94
Cash flow from operations [2]	**2 235**	2 740	2 344	2 426	2 650	2 721	1 982	2 393
per common share – basic (dollars)	**1.46**	1.78	1.51	1.55	1.69	1.73	1.26	1.52
Capital expenditures, including capitalized interest	**2 205**	1 670	1 606	1 478	1 814	1 519	1 941	1 576
ROCE [2] (%) for the twelve months ended	**7.3**	12.5	14.3	14.8	13.8	13.4	11.1	12.5
Common share information (dollars)								
Dividend per common share	**0.13**	0.13	0.13	0.11	0.11	0.11	0.11	0.10
Share price at the end of trading								
Toronto Stock Exchange (Cdn$)	**32.71**	32.34	29.44	32.59	29.38	26.76	37.80	43.48
New York Stock Exchange (US$)	**32.98**	32.85	28.95	32.70	28.83	25.44	39.10	44.84

(1) The company has reclassified 2011 operating revenues to reflect net presentation of certain transactions involving sales and purchases of third-party crude oil production in the Oil Sands segment that were previously presented on a gross basis.

(2) Non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this document. ROCE excludes capitalized costs related to major projects in progress.

Business Environment

Three months ended (average for the period ended, except as noted)		**Dec 31 2012**	Sept 30 2012	June 30 2012	Mar 31 2012	Dec 31 2011	Sept 30 2011	June 30 2011	Mar 31 2011
WTI crude oil at Cushing	US$/bbl	**88.20**	92.20	93.50	102.95	94.05	89.75	102.55	94.10
Dated Brent crude oil at Sullom Voe	US$/bbl	**110.10**	109.50	108.90	118.35	109.00	113.40	117.30	104.95
Dated Brent/Maya FOB price differential	US$/bbl	**17.30**	11.90	9.85	9.45	5.55	14.80	14.05	15.65
Canadian 0.3% par crude oil at Edmonton	Cdn$/bbl	**84.35**	84.70	84.45	92.80	98.20	92.50	103.85	88.40
WCS at Hardisty	US$/bbl	**70.05**	70.45	70.60	81.50	83.60	72.10	84.90	71.25
Light/heavy crude oil differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**18.15**	21.75	22.90	21.45	10.45	17.65	17.65	22.85
Condensate at Edmonton	US$/bbl	**98.10**	96.00	99.40	110.00	108.70	101.65	112.40	98.35
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**3.05**	2.20	1.85	2.50	3.40	3.70	3.75	3.80
New York Harbor 3-2-1 crack (1)	US$/bbl	**35.95**	37.80	31.95	25.80	22.80	36.45	29.25	19.40
Chicago 3-2-1 crack (1)	US$/bbl	**27.85**	35.15	27.85	18.80	19.20	33.30	29.70	16.45
Portland 3-2-1 crack (1)	US$/bbl	**29.85**	38.15	37.90	27.70	26.45	36.50	29.35	21.40
Gulf Coast 3-2-1 crack (1)	US$/bbl	**27.35**	33.95	29.30	25.45	20.40	33.10	27.30	18.50
Exchange rate	US$/Cdn$	**1.00**	1.00	0.99	1.00	0.98	1.02	1.03	1.01
Exchange rate (end of period)	US$/Cdn$	**1.01**	1.02	0.98	1.00	0.98	0.95	1.04	1.03

(1) 3-2-1 crack spreads are indicators of the refining margin generated by converting three barrels of WTI into two barrels of gasoline and one barrel of diesel. The crack spreads presented here generally approximate the regions into which the company sells refined products through retail and wholesale channels.

Significant or Unusual Items Impacting Net Earnings

Trends in Suncor's quarterly earnings results and cash flow from operations are driven primarily by production volumes, which can be significantly impacted by major planned maintenance events – such as the maintenance that occurred at many Exploration and Production assets in the third and fourth quarters of 2012 and the maintenance that occurred at Upgrader 2 in Oil Sands in the second quarter of 2011 – and unplanned maintenance outages, such as the one that occurred at Upgrader 2 in the first half of 2012.

Trends in Suncor's quarterly earnings results and cash flow from operations are also affected by changes in commodity prices, refining crack spreads and foreign exchange rates.

In addition to the impacts of changes in production volumes and business environment, net earnings over the last eight quarters were affected by the following events or significant one-time adjustments:

- Given Suncor's view of the challenging economic outlook for the Voyageur upgrader project, the company performed an impairment test in the fourth quarter of 2012. Based on an assessment of expected future net cash flows, the company recorded an after-tax impairment charge of $1.487 billion.
- The fourth quarter of 2012 included an after-tax impairment reversal of $177 million of the impairment charges recorded against its assets in Syria in the second quarter of 2012, due to a revised assessment of the net recoverable value of the underlying assets following the receipt of risk mitigation proceeds.
- The fourth quarter of 2012 included total after-tax impairment charges of $128 million for certain exploration, development and production assets in the Exploration and Production segment.
- The second quarter of 2012 included after-tax impairment charges and write-offs of $694 million against assets in Syria, which reflected the shut in of production due to political unrest and international sanctions. The company ceased recording all production and revenue from its Syrian assets in the fourth quarter of 2011.
- The second quarter of 2011 included after-tax impairment charges of $514 million against assets in Libya, which reflected the shut in of production due to political unrest and international sanctions. Production from all major fields in Libya was successfully restarted by the first quarter of 2012.
- The first quarter of 2011 included a $442 million adjustment to deferred income tax expense related to an increase in U.K. tax rates on oil and gas profits in the North Sea.
- As part of its strategic business alignment subsequent to the merger with Petro-Canada, Suncor divested a number of non-core assets in its Exploration and Production segment throughout 2010 and 2011. Decreases in production volumes in 2011 and the second half of 2010 were due in part to the disposition of these assets. The resulting gains and losses on the disposition of these assets had one-time impacts on net earnings in the quarters in which they occurred.

8. CAPITAL INVESTMENT UPDATE

The Capital Investment Update section contains forward-looking information. See the Advisory – Forward-Looking Information section of this MD&A for the material risks and assumptions underlying this forward-looking information.

Capital and Exploration Expenditures by Segment

Year ended December 31 ($ millions)	**2012**	2011	2010
Oil Sands	**4 957**	5 100	3 709
Exploration and Production	**1 261**	874	1 274
Refining and Marketing	**646**	633	667
Corporate, Energy Trading and Eliminations	**95**	243	360
Total	**6 959**	6 850	6 010
Less: capitalized interest on debt	**(587)**	(559)	(301)
	6 372	6 291	5 709

Capital and Exploration Expenditures by Type [(1)(2)(3)]

Year ended December 31 ($ millions)	Sustaining	Growth	**Total**
Oil Sands	2 293	2 114	**4 407**
Oil Sands Base	*1 342*	*604*	***1 946***
In Situ	*625*	*810*	***1 435***
Oil Sands Ventures	*326*	*700*	***1 026***
Exploration and Production	233	994	**1 227**
Refining and Marketing	637	6	**643**
Corporate, Energy Trading and Eliminations	91	4	**95**
	3 254	3 118	**6 372**

(1) Capital expenditures in this table exclude capitalized interest on debt.

(2) Growth capital expenditures include capital investments that result in i) an increase in production levels at existing Oil Sands operations and Refining and Marketing operations; ii) new facilities or operations that increase overall production; iii) new infrastructure that is required to support higher production levels; iv) new reserves or a positive change in the company's reserves profile in Exploration and Production operations; or v) margin improvement, by increasing revenues or reducing costs.

(3) Sustaining capital expenditures include capital investments that i) ensure compliance or maintain relations with regulators and other stakeholders; ii) improve efficiency and reliability of operations or maintain productive capacity by replacing component assets at the end of their useful lives; iii) deliver existing proved developed reserves for Exploration and Production operations; or iv) maintain current production capacities at existing Oil Sands operations and Refining and Marketing operations.

In 2012, Suncor spent $6.372 billion on capital for property, plant and equipment and exploration activities, and capitalized $587 million of interest on debt towards major development assets and construction projects. Activity in 2012 included the following.

Oil Sands Base

Oil Sands Base capital expenditures were $1.946 billion, of which $1.342 billion was directed towards sustaining activities. Sustaining capital expenditures related primarily to planned maintenance events and the company's TRO$_{TM}$ initiative, and included $496 million towards the construction of infrastructure and mature fine tailings drying facilities that will facilitate the company's TRO $_{TM}$ process going forward. The company commissioned the TRO$_{TM}$ project in the second quarter of 2012.

Oil Sands Base growth capital focused on infrastructure required to support growth in production from Oil Sands operations, including 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 be connected to the Enbridge Mainline system in 2013. Both assets are operated by third parties and subject to long-term arrangements.

In Situ

In Situ capital and exploration expenditures were $1.435 billion, of which $810 million was directed towards growth projects. As a result of the successful execution of Firebag Stage 4, the company commissioned the cogeneration units in the fourth quarter ahead of schedule, while the central processing facilities operated at 10% capacity throughout the fourth quarter of 2012. Steam injection was in progress for both Stage 4 well pads and first oil was achieved by the end of 2012. Capital expenditures for Firebag Stage 4 were $445 million in 2012, bringing total project expenditures to $1.634 billion.

In addition, Suncor continues to construct an insulated pipeline, which will transport bitumen without the requirement for additional diluent between Firebag and Suncor's Athabasca terminal starting in the second quarter of 2013.

In Situ sustaining capital expenditures of $625 million were directed primarily to the design and construction of well pads that are expected to maintain existing production levels from MacKay River and Firebag in future years. In December 2012, the company began steaming wells on a new pad at MacKay River. The company anticipates first oil from these wells in the first quarter of 2013.

Oil Sands Ventures

Suncor's share of capital expenditures for the Syncrude joint operation was $326 million, which included $150 million for mine train replacement at the Mildred Lake mining area and equipment relocation at the Aurora mining area, and $63 million for a composite tailings plant and a centrifuge plant as part of its tailings management plans.

Oil Sands Ventures growth capital expenditures were $700 million in 2012. The Voyageur upgrader project expenditures were focused on validating project scope, developing the project execution plan, engineering and progressing site preparation. The Fort Hills mining project expenditures were directed towards engineering, progressing with site preparation and the procurement of long-lead items. The Joslyn North mining project, which is in the earliest stage of development of the three projects, was focused on design engineering and site preparation.

Exploration and Production

Exploration and Production capital and exploration expenditures were $1.227 billion in 2012, of which $994 million was directed towards growth and exploration.

Growth spending included $217 million for Golden Eagle, which focused on detailed engineering and construction of topsides and platform jackets.

The company and co-owners of Hebron announced project sanction in the fourth quarter of 2012, for which Suncor has a 22.729% interest. Growth spending for Hebron was $200 million in 2012, which focused on engineering, site preparation, and the start of construction of the gravity-based structure.

Other growth capital included development drilling for Hibernia, White Rose, Terra Nova and Buzzard, and for North America Onshore in the Cardium oil formation in Western Canada, which started producing late in 2012.

During 2012, Suncor participated in two exploration wells offshore Norway: the second appraisal well for the Beta discovery and the first exploration well for the PL 477 licence, known as Cooper. The wells were deemed to be dry holes; therefore, the related exploration expenditures were expensed in 2012. For the Beta discovery, the company will continue to evaluate the prospect, and plans to acquire new seismic data in 2013 and participate in further appraisal drilling in 2014.

The company also participated in various exploration wells offshore the U.K. – including the Northern Terrace area of the Buzzard field and the Romeo prospect. The Northern Terrace well was successful while results for the Romeo well are currently being evaluated.

Sustaining capital expenditures focused primarily on the planned maintenance programs for East Coast Canada assets, including the replacement of the FPSO water injection swivel and subsea infrastructure at Terra Nova, and the propulsion system for the White Rose FPSO.

Other Capital Expenditures

Refining and Marketing spent $643 million on capital expenditures in 2012, largely focused on planned maintenance at the Sarnia and Commerce City refineries, and the lubricants plant. The company also completed the project to reduce benzene content in gasoline production at the Commerce City refinery.

Significant Growth Projects Update

	Description	Current Cost Estimate ($ millions)	Project Spend to Date ($ millions)	Target Completion	Estimated % Complete Engineering	Estimated % Complete Construction
Operated						
Firebag Stage 4	62.5 mbbls/d bitumen	1 668	1 634	Q1 2013	100	99
Non-operated [1]						
Golden Eagle [2]	18.7 mboe/d (net)	1 000 (±10%)	280	Q4 2014/ Q1 2015		
Hebron [2]	34.2 mboe/d (net)	3 185 (±10%)	306	Q4 2017		

(1) Estimated completion percentages not provided for non-operated projects. Cost estimates are based on the most recent estimate provided by the operator.

(2) Cost Estimate and Project Spend to Date figures do not include fair market value adjustments recorded as part of the merger with Petro-Canada in 2009.

The table above provides a review and update at December 31, 2012 of major growth projects that have been sanctioned for development by the company. Other growth projects, such as the Fort Hills and Joslyn North oil sands mining projects and the Voyageur upgrader project, have not yet received a final investment decision by the company or its Board of Directors and the respective owners of each of the individual projects. These projects are discussed under Other Capital Projects below.

Firebag Stage 4 is nearly complete and expected to be approximately 15% under the announced cost estimate of $2.0 billion. The company anticipates that bitumen production from Firebag will reach production capacity of 180,000 bbls/d over the next year.

The field development plan for the Golden Eagle Area Development includes stand-alone facilities designed for 70,000 boe/d of gross production. Activity in 2013 will focus on the completion and installation of platform jackets and wellhead topsides, followed by the start of development drilling. Capital expenditures for 2012 were $217 million, bringing total project expenditures to date to $280 million. The cost estimate of $1.0 billion has increased over the prior year primarily due to a change in the foreign exchange rate.

The co-owners for the Hebron project officially sanctioned development on December 31, 2012. The Hebron field includes a gravity-based structure design supporting an oil production rate of 150,000 bbls/d. The initial gross cost estimate for this project is $14 billion, of which Suncor's total project expenditures to date associated with the project scope are $306 million.

Other Capital Projects

Suncor also anticipates 2013 capital expenditures to be focused on the following projects and initiatives:

Oil Sands Base and In Situ

The company plans to focus growth capital efforts on optimizing the existing asset base by building new infrastructure to enhance marketing flexibility and takeaway capacity, and through the advancement of various debottlenecking projects in mining and extraction, and In Situ. These projects will be less capital intensive but are expected to result in high returns and efficiencies throughout the Oil Sands operations. The company has commenced a debottlenecking project at the MacKay River central processing facility, which is expected to increase production capacity to 38,000 bbls/d by 2015.

Sustaining capital includes planned maintenance events for the Upgrader 1 and Upgrader 2 facilities, a central processing facility at Firebag, and refurbishment of the Upgrader 1 hydrogen plant. Infrastructure and facilities to support the ongoing TRO$_{TM}$ process will continue in 2013.

Suncor plans to focus on the completion of the well pads in Firebag Stage 4, and continue infill well programs and development drilling in Firebag and MacKay River to maintain an inventory of future bitumen supply as production from older wells experience natural declines.

Oil Sands Ventures

Capital expenditures in 2013 for Syncrude are expected to focus on the mine train replacement for the Mildred Lake mining area, the mine train relocation at the Aurora mining area and sustaining maintenance initiatives.

Suncor continues to work closely with co-owners on evaluating and progressing Oil Sands Venture growth projects, including the Fort Hills and Joslyn North mining projects, and the Voyageur upgrader.

The partners of the Fort Hills mining project expect to reach a sanction decision in the second half of 2013.

Subject to the owners sanctioning the project, post sanction activities are expected to include the commencement of detailed engineering design, bulk equipment and material procurement, and site construction.

Suncor plans to provide an update on the targeted timing for a sanction decision on the Joslyn project when available. Design engineering and site preparation activities will be a continued focus in 2013.

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.

Exploration and Production

In addition to Golden Eagle and Hebron, capital expenditures for Exploration and Production operations are expected to focus on development drilling for Terra Nova, Hibernia, White Rose and Buzzard, the procurement of subsea equipment for the development of the HSEU, development of the South White Rose Extension initially as an alternate gas storage site that will permit ongoing development and production, and reliability enhancement projects for Buzzard.

In the North Sea, the company will act as operator for a planned exploration well in licence P1658 (Block 20/05b) known as the Scotney prospect. In addition, the company plans to participate in two non-operated exploration wells in the U.K. and evaluate development options on the Buzzard Northern Terrace and CPZ areas in 2013.

The company is participating in two non-operated exploration wells in Norway in 2013. On the Beta licence, Suncor will continue to evaluate the prospect, and plans to acquire new seismic data in 2013 and participate in further appraisal drilling in 2014.

For North America Onshore operations, the company plans to continue developing its play in the Cardium oil formation in Western Canada and further delineate its play in the Kobes/Altares region of B.C. in the Montney shale gas formation.

Refining and Marketing

The company expects that sustaining capital will focus on planned maintenance events and routine asset replacement, and that growth capital is expected to be deployed on projects to prepare the Montreal refinery to receive shipments of western crude feedstock.

Renewable Energy

The company continues to progress the Adelaide and Cedar Point wind projects through the regulatory process in 2013. The two projects are expected to add 140 MW of gross installed capacity, increasing the gross installed capacity of Suncor's wind projects by 55%.

9. FINANCIAL CONDITION AND LIQUIDITY

Indicators

At December 31 ($ millions, except as noted)	**2012**	2011
Return on Capital Employed (%) [1][2]		
Excluding major projects in progress	**7.3**	13.8
Including major projects in progress	**5.9**	10.1
Net debt to cash flow from operations [3] (times)	**0.7**	0.7
Interest coverage on long-term debt (times)		
Earnings basis [4]	**7.9**	10.7
Cash flow from operations basis [3][5]	**17.6**	16.4

(1) Non-GAAP financial measure. The calculations for ROCE are detailed in the Non-GAAP Financial Measures Advisory section of this MD&A.

(2) The after-tax impairment of $1.487 billion for the Voyageur upgrader project impacted ROCE by approximately 4% in 2012.

(3) Cash flow from operations and metrics that use cash flow from operations are non-GAAP financial measures. See the Non-GAAP Financial Measures Advisory section of this MD&A.

(4) Net earnings plus income taxes and interest expense, divided by the sum of interest expense and capitalized interest.

(5) Cash flow from operations plus current income taxes and interest expense, divided by the sum of interest expense and capitalized interest.

Capital Resources

Suncor's capital resources consist primarily of cash flow from operations, cash and cash equivalents, and available lines of credit. Suncor's management believes the company will have the capital resources to fund its planned 2013 capital spending program of $7.3 billion and meet current and long-term working capital requirements through existing cash balances and short-term investments, cash flow from operations, available committed credit facilities, issuing commercial paper and issuing long-term notes or debentures. The company's cash flow from operations depends on a number of factors, including commodity prices, production and sales volumes, refining and marketing margins, operating expenses, taxes, royalties and foreign exchange rates. If additional capital is required, Suncor's management believes adequate additional financing will be available to the company in debt capital markets at commercial terms and rates.

Cash and cash equivalents increased by $590 million to $4.393 billion during 2012, primarily due to strong cash flow from operations that exceeded capital expenditures, and the receipt of $300 million in risk mitigation proceeds related to the company's Syrian assets, partially offset by $1.451 billion of share repurchases, and $756 million in dividends. For the year ended December 31, 2012, the company's net debt to cash flow from operations measure was 0.7 times, which met management's target of less than 2.0 times.

Unutilized lines of credit at December 31, 2012 were $4.735 billion, compared to $4.428 billion at December 31, 2011.

A summary of available and utilized credit facilities is as follows:

At December 31, 2012 ($ millions)	
Fully revolving for a period of one year after term-out date (November 2013)	2 000
Fully revolving and expires in 2013-2014	924
Fully revolving for a period of four years and expires in 2016	3 000
Can be terminated at any time at the option of the lenders	379
Total available credit facilities	6 303
Less:	
Credit facilities supporting outstanding commercial paper	775
Credit facilities supporting standby letters of credit	793
Total unutilized credit facilities	4 735

Financing Activities

Management of debt levels continues to be a priority for Suncor given the company's long-term growth plans. Suncor's management believes a phased and flexible approach to existing and future growth projects should assist Suncor in maintaining its ability to manage project costs and debt levels.

Suncor's interest on debt (before capitalized interest) in 2012 was $643 million, compared to $661 million in 2011. The reduction of short-term debt and the repayment of certain medium term notes in the third quarter of 2011 resulted in lower interest in 2012 compared to 2011, partially offset by the interest paid on two new finance leases in 2012.

Change in Net Debt

($ millions)

Net debt – December 31, 2011	6 976
Decrease in net debt	(344)
Net debt – December 31, 2012	6 632
Decrease in net debt	
Cash flow from operations	9 745
Capital and exploration expenditures and Other investments	(6 962)
Proceeds from divestitures	68
Dividends less proceeds from exercise of share options	(568)
Repurchase of common shares	(1 451)
Change in non-cash working capital and other	(650)
Foreign exchange on cash, long-term debt and other balances	162
	344

At December 31, 2012, Suncor's net debt was $6.632 billion, compared to $6.976 billion at December 31, 2011. During 2012, net debt decreased by $344 million, largely due to cash flow from operations that exceeded capital and exploration expenditures, the receipt of $300 million in risk mitigation proceeds related to the company's Syrian assets, the impact of the strengthening Canadian dollar relative to the U.S. dollar on the valuation of long-term debt, partially offset by cash returned to shareholders in the form of share repurchases and dividends, and an increase in non-cash working capital.

Total Debt to Total Debt Plus Shareholders' Equity

Suncor is subject to financial and operating covenants related to its bank debt and public market debt. Failure to meet the terms of one or more of these covenants may constitute an Event of Default as defined in the respective debt agreements, potentially resulting in accelerated repayment of one or more of the debt obligations. The company is in compliance with its financial covenant that requires total debt to not exceed 60% of its total debt plus shareholders' equity. At December 31, 2012, total debt to total debt plus shareholders' equity was 22% (December 31, 2011 – 22%). The company is also currently in compliance with all operating covenants.

At December 31 ($ millions, except as noted)	**2012**	2011
Short-term debt	**776**	763
Current portion of long-term debt	**311**	12
Long-term debt	**9 938**	10 004
Total debt	**11 025**	10 779
Less: Cash and cash equivalents	**4 393**	3 803
Net debt	**6 632**	6 976
Shareholders' equity	**39 223**	38 600
Total debt plus shareholders' equity	**50 248**	49 379
Total debt to total debt plus shareholders' equity (%)	**22**	22

Short-Term Investments

The company has invested excess cash in short-term financial instruments that are presented as cash and cash equivalents. The objectives of the company's short-term investment portfolio are to ensure the preservation of capital, maintain adequate liquidity to meet Suncor's cash flow requirements and deliver competitive returns consistent with the quality and diversification of investments within acceptable risk parameters. The maximum weighted average term to maturity of the short-term investment portfolio will not exceed six months, and all investments will be with counterparties with investment grade debt ratings. As at December 31, 2012, the weighted average term to maturity of the short-term investment portfolio was approximately 30 days. In 2012, the company earned approximately $32.0 million of interest income on this portfolio.

Credit Ratings

The following information regarding the company's credit ratings is provided as it relates to the company's cost of funds and liquidity and indicates whether or not the company's credit ratings have changed. In particular, the company's ability to access unsecured funding markets and to engage in certain collateralized business activities on a cost-effective basis is primarily dependent upon maintaining competitive credit ratings. A lowering of the company's credit rating may also have potentially adverse consequences for the company's funding capacity or access to 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 company's long-term senior debt ratings are:

Long-Term Senior Debt	Rating	Long-Term Outlook
Standard & Poor's	BBB+	Stable
Dominion Bond Rating Service	A (low)	Stable
Moody's Investor Services	Baa1	Stable

The company's commercial paper ratings are:

Commercial Paper	Cdn$ Rating	US$ Rating
Standard & Poor's	A-1 (low)	A-2
Dominion Bond Rating Service	R-1 (low)	Not rated
Moody's Investors Service	Not rated	P-2

In 2012, Moody's Investors Service upgraded the company's long-term senior debt rating from Baa2 to Baa1, and changed its long-term outlook from positive to stable. All other credit ratings are consistent with 2011. Refer to the Description of Capital Structure – Credit Ratings section of Suncor's 2012 AIF for a description of credit ratings listed above.

Common Shares

Outstanding Shares

December 31, 2012 (thousands)

Common shares	1 523 057
Common share options – exercisable and non-exercisable	47 366
Common share options – exercisable	29 879

As at February 22, 2013, the total number of common shares outstanding was 1,523,644,237, and the total number of exercisable and non-exercisable common share options outstanding was 75,233,036. Once exercisable, each outstanding common share option is convertible into one common share.

Share Repurchases

During the first quarter of 2012, the company obtained regulatory approval from the Toronto Stock Exchange (TSX) to recommence a Normal Course Issuer Bid (the 2011 NCIB) under which the company was authorized to purchase for cancellation up to an additional $1.0 billion of Suncor's common shares between February 28, 2012 and September 5, 2012.

For the 2011 NCIB, the company repurchased 33,032,400 shares during 2012 at an average price of $30.28 per share, for a total repurchase cost of $1.0 billion.

During the second quarter of 2012, the company obtained regulatory approval in Canada for a program to issue put options on the company's common shares as part of the 2011 NCIB. Under this program, Suncor was permitted to issue put options to a Canadian financial institution, which entitled the purchaser, on the expiry date of the relevant options, to sell to Suncor a specified number of Suncor common shares at a price agreed to on the date the options were issued.

The company received $1.3 million in premiums for issuing 1,250,000 put options. No shares were repurchased through the exercise of put options, as all options expired unexercised. Cash premiums received by Suncor for issuing the put options were recorded as an increase to shareholders' equity and netted against the cash paid for the purchase of common shares for cancellation. Premiums received by Suncor for issuing put options do not impact the company's earnings.

In the third quarter of 2012, the company obtained regulatory approval for another Normal Course Issuer Bid (the 2012 NCIB) with the TSX authorizing the purchase for cancellation of up to $1.0 billion of its common shares. The 2012 NCIB commenced on September 20, 2012 and will end no later than September 19, 2013. Pursuant to the 2012 NCIB, Suncor has agreed that it will not purchase more than 38,392,005 common shares, which represented approximately 2.5% of issued and outstanding common shares as at September 14, 2012. The company subsequently announced it had entered into an automatic purchase plan with a designated broker to allow for the repurchase of common shares during scheduled and unscheduled share-trading blackout periods. Shareholders may obtain a copy of the company's Notice of Intention to make a Normal Course Issuer Bid by contacting Investor Relations.

For the 2012 NCIB, the company repurchased 13,829,900 shares during 2012 at an average price of $32.68 per share, for a total repurchase cost of $452 million. Subsequent to December 31, 2012, the company had repurchased an additional 3,915,646 shares under the 2012 NCIB at an average price of $32.45 per share for a total repurchase cost of $127 million, as of February 22, 2013.

At December 31 ($ millions, except as noted)	2012	2011
Share repurchase activities (thousands of common shares)		
Shares repurchased directly	**46 862**	17 128
Shares repurchased through exercise of put options	**—**	—
	46 862	17 128
Share repurchase cost ($ millions)		
Repurchase cost	**1 452**	500
Option premiums received	**(1)**	—
	1 451	500
Weighted average repurchase price per share, net of option premiums (dollars)	**30.96**	29.19

Contractual Obligations, Commitments, Guarantees, and Off-Balance Sheet Arrangements

In addition to the enforceable and legally binding obligations quantified in the table presented below, Suncor has other obligations for goods and services that were entered into in the normal course of business, which may terminate on short notice, including commitments for purchase of commodities for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase.

The company does not believe it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial condition or financial performance, including liquidity and capital resources.

In the normal course of business, the company is obligated to make future payments, including contractual obligations and non-cancellable commitments.

		Payments Due by Period			
($ millions)	Total	2013	2014 to 2015	2016 to 2017	Thereafter
Fixed and revolving-term debt [1]	**19 950**	**1 662**	**1 543**	**1 112**	**15 633**
Finance lease payments	**2 487**	**94**	**189**	**189**	**2 015**
Decommissioning and restoration costs [2]	**8 154**	**413**	**779**	**694**	**6 268**
Operating lease agreements, pipeline capacity and energy services commitments	**13 721**	**1 572**	**2 276**	**1 697**	**8 176**
Exploration work commitments	**272**	**67**	**205**	**—**	**—**
Other long-term obligations [3]	**449**	**149**	**300**	**—**	**—**
Total	**45 033**	**3 957**	**5 292**	**3 692**	**32 092**

(1) Includes debt that is redeemable at Suncor's option and interest payments on fixed-term debt.

(2) Represents the undiscounted amount of obligations associated with land and tailings reclamation and site restoration and decommissioning costs.

(3) Includes the Libya ESPA signature bonus and merger consent, and Fort Hills purchase obligations. See the Accrued Liabilities and Other – Long-Term Financial Liabilities note to the 2012 audited Consolidated Financial Statements.

Transactions with Related Parties

The company enters into transactions with related parties in the normal course of business. These transactions primarily include sales to associated entities in the company's Refining and Marketing segment. For more information on these transactions and for a summary of Compensation of Key Management Personnel, refer to the Related Party Disclosures note to the 2012 audited Consolidated Financial Statements.

Financial Instruments

Suncor periodically enters into derivative contracts for risk management purposes. The derivative contracts hedge risks related to purchases and sales of commodities, to manage exposure to interest rates and to hedge risks specific to individual transactions. For the year ended December 31, 2012, the pre-tax earnings impact for risk management activities was a gain of $1 million (2011 – pre-tax loss of $22 million).

The company's Energy Trading business uses crude oil, natural gas, refined product and other derivative contracts to generate net earnings. For the year ended December 31, 2012, the pre-tax earnings impact for Energy Trading activities was a gain of $246 million (2011 – pre-tax gain of $301 million).

Gains or losses related to derivatives are recorded as Other Income in the Consolidated Statements of Comprehensive Income.

($ millions)	Risk Management	Energy Trading	Total
Fair value of contracts outstanding – January 1, 2011	13	(87)	(74)
Fair value of contracts realized during the year	9	(248)	(239)
Changes in fair value during the year	(22)	301	279
Fair value of contracts outstanding – December 31, 2011	—	(34)	(34)
Fair value of contracts realized during the year	**(2)**	**(255)**	**(257)**
Changes in fair value during the year	**1**	**246**	**247**
Fair value of contracts outstanding – December 31, 2012	**(1)**	**(43)**	**(44)**

The fair value of derivatives are recorded in the Consolidated Balance Sheets as follows:

Fair value of derivative contracts at December 31 ($ millions)	**2012**	2011
Accounts receivable	**53**	37
Accounts payable	**(97)**	(71)
	(44)	(34)

Risks Associated with Derivative Financial Instruments

Suncor may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to fulfil their obligations under these contracts. The company minimizes this risk by entering into agreements with investment grade counterparties. Risk is also minimized through regular management review of the potential exposure to and credit ratings of such counterparties. Suncor's exposure is limited to those counterparties holding derivative contracts with net positive fair values at a reporting date.

Suncor's risk management activities are subject to periodic reviews by management to determine appropriate hedging requirements based on the company's tolerance for exposure to market volatility, as well as the need for stable cash flow to finance future growth. Energy Trading activities are governed by a separate risk management group that reviews and monitors practices and policies and provides independent verification and valuation of these activities.

For further details on our derivative financial instruments, including assumptions made in the calculation of fair value, a sensitivity analysis of the effect of changes in commodity prices on our derivative financial instruments, and additional discussion of exposure to risks and mitigation activities, see the Financial Instruments and Risk Management note in our 2012 audited Consolidated Financial Statements.

10. ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

Changes in Accounting Policies

There were no changes to Suncor's significant accounting policies in 2012, which are described in note 3 to the December 31, 2012 audited Consolidated Financial Statements.

Recently Announced Accounting Standards

Financial Instruments: Recognition and Measurement

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

Fair Value Measurements

In May 2011, the IASB issued IFRS 13 *Fair Value Measurement*, which establishes a single source of guidance for most fair value measurements, clarifies the definition of fair value, and enhances the disclosures on fair value measurement. Prospective application of this standard is effective for fiscal years beginning on or after January 1, 2013. The company does not expect any changes to its fair value measurements; however, expanded disclosures on fair value measurements are required.

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IFRS 7 *Financial Instruments: Disclosures* and IAS 32 *Financial Instruments: Presentation* to clarify the current offsetting model and develop common disclosure requirements to enhance the understanding of the potential effects of offsetting arrangements. Retrospective application of amendments to IFRS 7 are effective for annual and interim periods starting on or after January 1, 2013. Retrospective application of amendments to IAS 32 are effective for annual periods starting on or after January 1, 2014, with earlier application permitted. The adoption of these amended standards is not expected to have a material impact on the company's financial statements; however, expanded disclosures on financial instruments that are offset in the Consolidated Balance Sheets will be required.

Presentation of Items of Other Comprehensive Income

In June 2011, the IASB issued amendments to IAS 1 *Presentation of Items of Other Comprehensive Income* to group items presented within Other Comprehensive Income based on whether they may be subsequently reclassified to net earnings. The amendment is required to be retrospectively adopted for periods beginning on or after July 1, 2012. The company does not expect a significant change to its presentation of items of other comprehensive income.

Scope of a Reporting Entity

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

IFRS 10 creates a single consolidation model by revising the definition of control in order to apply the same control criteria to all types of entities, including joint arrangements, associates and structured entities. IFRS 11 establishes a principle-based approach to the accounting for joint arrangements by focusing on the rights and obligations of the arrangement and limits the application of proportionate consolidation accounting to arrangements that meet the definition of a joint operation. Arrangements that meet the definition of a joint venture are required to apply the equity method of accounting. IFRS 12 is a comprehensive disclosure standard for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities. IAS 27 has been amended to conform to the changes made in IFRS 10 but retains the guidance on separate financial statements. IAS 28 has also been amended to conform to the changes made in IFRS 10 and 11.

Retrospective application of these standards with relief for certain transactions is effective for fiscal years beginning on or after January 1, 2013. The company has identified two existing joint arrangements in the Refining and Marketing segment that will be required to change from proportionate consolidation to equity accounting as a result of IFRS 11. This change will not have a material impact to the consolidated financial statements, but will result in the netting of revenues and expenses (2012 – approximately $100 million and $90 million, respectively) for these entities into Other Income. In addition, the

company's net investment in these entities will be presented in Other Assets.

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19 *Employee Benefits,* which revises the recognition, presentation and disclosure requirements for defined benefit plans. The revised standard requires immediate recognition of actuarial gains and losses in other comprehensive income thereby eliminating the previous options that were available, changes the calculation and presentation of the interest cost component of annual pension expense and enhances the disclosure requirements for defined benefit plans. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2013. The company anticipates a net incremental increase to expenses of approximately $50 million for 2012 as a result of these amendments.

Production Stripping Costs

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

Critical Accounting Estimates and Judgments

The preparation of financial statements in accordance with GAAP requires management to make estimates, judgments and assumptions that affect reported assets, liabilities, revenues, expenses, gains, losses, and disclosures of contingencies. These estimates and assumptions are subject to change based on experience and new information.

Critical accounting estimates are those estimates that require management to make assumptions about matters that are highly uncertain at the time the estimate is made, and those estimates where changes in critical assumptions that are within a range of reasonably possible outcomes would have a material impact on the company's financial condition, changes in financial condition or financial performance.

Critical accounting estimates are reviewed annually by the Audit Committee of the Board of Directors. The following are the critical accounting estimates used in the preparation of Suncor's December 31, 2012 audited Consolidated Financial Statements.

Oil and Gas Reserves and Resources

Certain measurements of depletion, depreciation, amortization, impairment and decommissioning and restoration obligations are determined in part based on the company's estimate of oil and gas reserves and resources. Although not reported as part of the company's 2012 audited Consolidated Financial Statements, these estimates of reserves and resources can have a significant impact on the Consolidated Financial Statements.

The estimation of reserves involves the exercise of professional judgment. Reserves and certain resources were evaluated or reviewed as at December 31, 2012 by qualified reserves evaluators in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* . The reserves and resources estimates are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook.

Oil and gas reserves and resources estimates are based on a range of geological, technical and economic factors, including projected future rates of production, estimated commodity prices, engineering data, and the timing and amount of future expenditures, all of which are subject to uncertainty. Where possible assumptions reflect market and regulatory conditions existing at December 31, 2012, which could differ significantly from other points in time throughout the year or in future periods.

Oil and Gas Activities

The company is required to use judgment when designating the nature of oil and gas activities as exploration, evaluation, development or production, and when determining whether the initial costs of these activities are capitalized.

Exploration and Evaluation Costs

The costs of drilling exploratory wells are initially capitalized pending the evaluation of commercially recoverable resources. The determination that commercial resources have been discovered requires judgment. If a judgment is made that there are no commercially recoverable resources, the associated exploration costs are charged to exploration expense. Evaluation costs incurred when management is assessing whether there are commercially recoverable resources and designing development and front-end engineering plans are capitalized. Exploration and evaluation assets are subject to ongoing technical, commercial and management review

to confirm the continued intent to develop and extract the underlying resources. When management is making this assessment, changes to project economics, quantities of resources, expected production techniques, unsuccessful drilling, and estimated production costs and projected capital expenditures are important factors. If a judgment is made that extraction of the resources is not commercially viable, the associated exploration and evaluation assets are impaired and charged to depreciation, depletion, amortization and impairment expense.

Development Costs

Management uses judgment to determine when exploration and evaluation assets are reclassified to property, plant and equipment. This decision considers several factors, including the existence of reserves, the receipt of the appropriate approvals from regulatory bodies and the company's internal project approval processes. After an oil and gas property is reclassified to property, plant and equipment, all subsequent development costs are capitalized.

Impairment of Assets

A cash-generating unit (CGU) is the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of the company's assets into CGUs requires significant judgment with respect to the integration between assets, the use of shared infrastructure, the existence of active markets for the company's products and the way in which management monitors operations.

At the end of each reporting period, the company is required to identify events or conditions that indicate that the net carrying value of a CGU might be impaired. Management uses judgment to determine if a specific event or condition is an indication of impairment for a CGU. If any such indication exists, the company must complete an impairment assessment for the CGU. A CGU is impaired when the net carrying value of the CGU exceeds management's estimate of the recoverable amount of the CGU, which is the higher of the CGU's fair value less costs to sell and its value-in-use.

Regardless of any indication of impairment, the company must complete an annual impairment assessment for any CGU, or group of CGUs, whose net carrying value includes indefinite-life intangible assets or an allocation of goodwill. For Suncor, this includes impairment assessments of the Oil Sands segment and the Refining and Marketing segment. For 2012, the company completed this review as at July 31, 2012, and determined that the underlying CGUs were not impaired.

At the end of each reporting period, the company must exercise judgment to determine if there are indicators that conditions causing a previous impairment have reversed. Where new estimates of recoverable amount exceed net carrying value, previously recorded impairment adjustments are reversed, up to the amount of the original impairment. An impairment of goodwill cannot be reversed.

For Suncor, the estimated recoverable amount of a CGU is predominantly determined using discounted net future cash flow models. The key assumptions the company uses for estimating future cash flows are estimates of future commodity prices, reserves and resources estimates, expected production volumes, estimated future operating and development costs, and estimated refining margins. The estimated useful life of the CGU, the timing of future cash flows and discount rates are also important assumptions made by management. Management may also be required to make judgments about the likelihood of occurrence of a future event, which may have an impact on key assumptions. Changes to these estimates and judgments will affect the recoverable amount of a CGU and may require a material impairment to the net carrying value of that CGU.

The company also assesses the impairment of assets when they are classified as held for sale or when they are reclassified from Exploration and evaluation assets to Property, plant and equipment. Assets held for sale are measured at the lower of net carrying value and fair value less costs to sell, which may be determined based on expected sale proceeds.

The following discusses important impairment assessments completed during 2012:

Voyageur Upgrader Project

At December 31, 2012, Suncor's view was that the economic outlook for the Voyageur upgrader project was challenged and, therefore, performed an impairment test, resulting in an after-tax impairment charge of $1.487 billion. The net recoverable amount was estimated under a fair value less costs to sell methodology and determined using an expected cash flow approach.

Key assumptions included current forecasts for the price of commodities, an estimate of price realizations, estimates of future operating and capital expenditures, and an after-tax risk-adjusted discount rate of 10%. As at December 31, 2012, the company's carrying value for assets relating to the Voyageur upgrader project was approximately $345 million.

Syria

As a result of political unrest and international sanctions announced in December 2011, the company suspended its

operations in Syria and ceased recording production or revenues. Suncor performed an impairment test on its assets in Syria at December 31, 2011 and determined that the assets were not impaired at that time.

As there had been no resolution of the political situation at the end of the second quarter of 2012, another impairment test on the company's Syrian assets was performed. As a result, the company recognized an after-tax impairment charge of $604 million against Property, plant and equipment, a write-down of receivables of $67 million and a write-down of $23 million against current assets.

During the fourth quarter of 2012, the company received risk mitigation proceeds of $300 million in respect of its Syrian operations. A portion, or all of these proceeds, may be repayable if operations in Syria resume and, therefore, were recorded as a provision in 2012 rather than to earnings. After receipt of the risk mitigation proceeds, an additional impairment test was performed at December 31, 2012, resulting in an after-tax impairment reversal of $177 million against assets in Syria.

The carrying value as at December 31, 2012 was based on a net recoverable amount that was estimated under a value-in-use methodology and determined using an expected cash flow approach, under probability weighted scenarios representing i) resumption of operations in one year, ii) resumption of operations in five years, and iii) total loss. The two scenarios where the company resumes operations incorporated repayment of the risk mitigation proceeds in accordance with the terms of the agreement.

Scenarios involving the company resuming normal operations used current forecasts for the price of commodities, the company's estimate of price realizations, estimates of operating and development expenditures based on the field development anticipated by Suncor's business plans prior to the suspension of operations, a discount rate (19%) that represented management's best estimate of the ongoing risk involved with operating in Syria, and management's best estimate of the incremental rebuilding costs to bring operations back on-stream. Management's forecasts for production were based on the most recently available estimate of future production volumes evaluated by Suncor's internal qualified reserves evaluators. The resulting carrying value of the company's property, plant, and equipment in Syria net of the risk mitigation provision at December 31, 2012 was approximately $130 million.

Fair Value of Financial Instruments

To estimate the fair value of financial instruments, the company uses quoted market prices when available, or models that use observable market data. In addition to market information, Suncor incorporates transaction-specific details that market participants would use in a fair value measurement, including the impact of non-performance risk. Inputs used in determining fair value are characterized using a hierarchy that prioritizes inputs depending on the degree to which they are observable. The company's estimate of fair value may differ from amounts that could be realized or settled in a current market transaction.

Provisions for Decommissioning and Restoration Costs

The company recognizes liabilities for the future decommissioning and restoration of property, plant and equipment. Management applies judgment in assessing the existence and extent of the company's decommissioning and restoration obligations at the end of each reporting period, as well as in determining whether the nature of the activities performed is related to decommissioning and restoration activities or normal operating activities.

These provisions are based on estimated costs, which take into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible future use of the site. Since these estimates are specific to the assets involved, there are many individual judgments and assumptions underlying Suncor's total provision. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience and changes in prices. The expected timing of future decommissioning and restoration activities may change due to certain factors, including oil and gas reserves life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

The fair value of these provisions is estimated by discounting the expected future cash flows using the company's credit-adjusted risk-free interest rate. In subsequent periods, the provision is adjusted for the passage of time by charging an amount to accretion of liabilities in financing expenses, based on the discount rate.

Suncor's provision for decommissioning and restoration costs increased by $887 million in 2012 to $4.688 billion. The most significant change in the provision was with respect to the revised future cost estimates and increased disturbance. The provision also increased due to a decrease in the average discount rate (2012 – 3.75%; 2011 – 4.3%).

Other Provisions

The determination of other provisions, including, but not limited to, provisions for royalty disputes, onerous contracts, litigation and constructive obligations, is a complex process that involves judgments about the outcomes of future events, the interpretation of laws and regulations, expected future cash flows and discount rates.

The company is involved in litigation and claims in the normal course of operations. As at December 31, 2012, management believes the result of any settlements related to such litigation or claims would not materially affect the financial position of the company.

Employee Future Benefits

The company provides benefits to employees and retired employees, including pensions and other post-retirement benefits.

The obligations and costs of defined benefit pension and other post-retirement benefit plans are determined based on actuarial valuation methods and assumptions. Assumptions typically used in determining these amounts include estimates of, as applicable, rates of employee turnover, future claim costs, discount rates, future salary and benefit levels, the return on plan assets, mortality rates and future medical costs. The accrued net benefit liability is reported as other long-term liabilities in the Consolidated Balance Sheets.

The fair value of plan assets is determined using market values. The estimated rate of return on plan assets in the portfolio considers the current level of returns on fixed income assets, the historical level of risk premium associated with other asset classes and the expected future returns on all asset classes. The discount rate assumption is based on the year-end interest rates for high-quality bonds that mature at times concurrent with the company's benefit obligations. The estimated rate for compensation increases is based on management's judgment.

Actuarial valuations are subject to management's judgment. Actuarial gains and losses comprise changes to assumptions related to discount rates, expected return on plan assets and annual rates for compensation increases. They are accounted for on a prospective basis and may have a material impact on the amounts presented. Actuarial gains and losses are recognized in other comprehensive income in the Consolidated Statements of Comprehensive Income in the period incurred.

Control and Significant Influence

Control is defined as the power to govern the financial and operating decisions of an entity so as to obtain benefits from its activities and significant influence is defined as the power to participate in the financial and operating decisions of the investee. The assessment of whether the company has control, joint control, or significant influence over another entity requires judgment of the impact it has over the financial and operating decisions of the entity and the extent of the benefits it obtains.

Income Taxes

The determination of the company's income tax provision is an inherently complex process, requiring management to interpret continually changing regulations and to make other judgments, including those about deferred income taxes that are discussed below.

Management believes that adequate provisions have been made for all income tax obligations, although the results of audits and reassessments and changes in the interpretations of standards may result in a material increase or decrease in the company's assets, liabilities and net earnings.

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 the 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.

Deferred Income Taxes

A taxable or a deductible temporary difference may exist when there is a difference between the carrying value of an asset or liability and its respective tax basis. The reversal of deductible temporary differences results in deductible amounts when determining taxable income in future periods. The reversal of taxable temporary differences results in taxable amounts when determining taxable income of future periods.

Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in the foreseeable future. To the extent that future taxable income and the application of existing tax laws in each jurisdiction differ significantly from the

company's estimate, the ability of the company to realize the deferred tax assets could be impacted.

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

11. RISK FACTORS

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 Organization of Petroleum Exporting Countries (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 light/heavy 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 feedstocks, levels of refined product inventories, regional refinery availability, marketplace competitiveness, and other local market factors.

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

Commodity prices and refining margins have fluctuated widely in recent years. Given the recent global economic uncertainty, we expect continued volatility and uncertainty in commodity prices in the near term. 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 greenhouse gas (GHG) and other emissions, the export of crude oil, natural gas and other products, the company's interactions with foreign governments, the awarding or acquisition of exploration and production rights, oil sands leases or other interests, the imposition of specific drilling obligations, control over the development and abandonment of fields and mine sites (including restrictions on production), and possibly expropriation or cancellation of contract rights.

Changes in government policy or regulation, 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 carbon dioxide (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 Low Carbon Fuel Standard (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 Land-Use Framework (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 Lower Athabasca Regional Plan (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.

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 Royalty Amending Agreement (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 National Oil Company 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.

Environment Health and Safety (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 the 2012 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 shut down 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 steam-to-oil ratios 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.

Other Risk Factors

A detailed discussion of additional risk factors is presented in our 2012 AIF / Form 40-F, filed with securities regulators.

12. OTHER ITEMS

CONTROL ENVIRONMENT

Based on their evaluation as of December 31, 2012, Suncor's Chief Executive Officer and Chief Financial Officer concluded that the company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the United States Securities Exchange Act of 1934, 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 the 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 damages. 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.

The effectiveness of our internal control over financial reporting as at December 31, 2012 was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2012.

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

13. NON-GAAP FINANCIAL MEASURES ADVISORY

Certain financial measures in the MD&A – namely operating earnings, ROCE, cash flow from operations and Oil Sands cash operating costs – are not prescribed by GAAP. These non-GAAP financial measures are included because management uses the information to analyze operating performance, leverage and liquidity. These non-GAAP financial measures do not have any standardized meaning and, therefore, are unlikely to be comparable to similar measures presented by other companies. Therefore, these non-GAAP financial measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. Except as otherwise indicated, these non-GAAP measures are calculated and disclosed on a consistent basis from period to period. Specific adjusting items may only be relevant in certain periods.

Operating Earnings

Operating earnings is a non-GAAP financial measure that adjusts net earnings for significant items that are not indicative of operating performance. Management uses operating earnings to evaluate operating performance, because management believes it provides better comparability between periods. Operating earnings are reconciled to net earnings in the Consolidated Financial Information segment of the MD&A.

The following is a reconciliation of net earnings to operating earnings for Suncor's last five years of operations. Operating earnings for 2009 and 2008 are reported under Previous GAAP and have been adjusted from operating earnings previously reported to include the effect of project start-up costs and mark-to-market valuation of stock-based compensation, which were previously excluded when calculating operating earnings.

($ millions)	**2012**	2011	2010	2009	2008
Net earnings as reported	**2 783**	4 304	3 829	1 146	2 137
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(157)**	161	(372)	(798)	852
Impairments and write-offs	**2 176**	629	306	42	—
Impact of income tax rate adjustments on deferred income taxes	**88**	442	—	4	—
Loss (gain) on significant disposals	**—**	107	(826)	39	—
Adjustments to provisions for assets acquired through the merger	**—**	31	68	97	—
Change in fair value of commodity derivatives used for risk management, net of realizations	**—**	—	(233)	499	(372)
Redetermination of working interests in Terra Nova	**—**	—	(166)	24	—
Modification of the bitumen valuation methodology	**—**	—	(51)	50	—
Merger and integration costs	**—**	—	79	151	—
Gain on effective settlement of pre-existing contract with Petro-Canada	**—**	—	—	(438)	—
Costs related to deferral of growth projects	**—**	—	—	299	
Operating earnings	**4 890**	5 674	2 634	1 115	2 617

Bridge Analyses of Operating Earnings

Throughout this MD&A, the company presents charts that illustrate the change in operating earnings from the comparative period through key variance factors. Factors represent after-tax variances and include the impacts of operating earnings adjustments. These factors are analyzed in the Operating Earnings narratives following the bridge analyses in a particular section of the MD&A. This bridge analysis is presented because management uses this presentation to analyze performance.

The factor for Volumes is calculated based on production volumes and mix for the Oil Sands and Exploration and Production segments and sales volumes for the Refining and Marketing segment.

The factor for Price, Margin and Other Revenue includes upstream price realizations before royalties, refining and marketing margins, other operating revenues, and the net impacts of sales and purchases of third-party crude.

The factor for Inventory reflects the opportunity cost of building production volumes in inventory or the additional margin earned by drawing down inventory produced in previous periods. The calculation of the Inventory factor in a bridge analysis permits the company to present the factor for Volumes for upstream assets based on production volumes, rather than based on sales volumes.

The factor for Operating Expense includes transportation expense, project start-up costs, and operating, selling and general expense (adjusted for impacts of changes in inventory).

The factor for Financing Expense and Other Income includes financing expense, other income, operational foreign exchange gains and losses, changes in gains and losses on disposal of assets that are not operating earnings adjustments, changes in statutory income tax rates, and other income tax adjustments.

Return on Capital Employed (ROCE)

ROCE is a non-GAAP financial measure that management uses to analyze operating performance and the efficiency of Suncor's capital allocation process. Average capital employed is calculated as a thirteen-month average of the capital employed balance at the beginning of the twelve-month period and the month-end capital employed balances throughout the remainder of the twelve-month period. Figures for capital employed at the beginning and end of the twelve-month period are presented to show the changes in the components of the calculation over the twelve-month period.

The company presents two ROCE calculations – one including and one excluding the impacts on capital employed of major projects in progress. Major projects in progress includes accumulated capital expenditures and capitalized interest for significant projects still under construction or in the process of being commissioned, and acquired assets that are still being evaluated. Management uses ROCE excluding the impacts of major projects in progress on capital employed to assess performance of operating assets.

Year ended December 31 ($ millions, except as noted)		**2012**	2011	2010	2009	2008
Adjustments to net earnings						
Net earnings		**2 783**	4 304	3 829	1 146	2 137
Add after-tax amounts for:						
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt		**(157)**	161	(372)	(858)	852
Net interest expense		**41**	83	327	349	—
	A	**2 667**	4 548	3 784	637	2 989
Capital employed – beginning of twelve-month period						
Net debt		**6 976**	11 254	13 516	7 226	3 248
Shareholders' equity		**38 600**	35 192	32 485	14 523	11 896
	D	**45 576**	46 446	46 001	21 749	15 144
Capital employed – end of twelve-month period						
Net debt		**6 632**	6 976	11 254	13 377	7 226
Shareholders' equity		**39 223**	38 600	35 192	34 111	14 523
		45 855	45 576	46 446	47 488	21 749
Average capital employed [1]	B	**45 342**	44 956	46 075	35 128	18 447
ROCE – including major projects in progress (%)	A/B	**5.9**	10.1	8.2	1.8	16.2
Average capitalized costs related to major projects in progress	C	**8 729**	12 106	12 890	10 655	5 149
ROCE – excluding major projects in progress (%)	A/(B-C)	**7.3**	13.8	11.4	2.6	22.5

(1) For 2009 to 2012, average capital employed is calculated as a thirteen-month average of the capital employed balance at the beginning of the twelve-month period and the month-end capital employed balances throughout the remainder of the twelve-month period. For 2008, average capital employed is calculated on the basis of a simple average (B+D)/2. This change in calculation was made as a result of the significant capital employed acquired in the merger with Petro-Canada in 2009. Figures for capital employed at the beginning and end of the twelve-month period are presented to show the changes in the components of the calculation over the twelve-month period.

Cash Flow from Operations

Cash flow from operations is a non-GAAP financial measure that adjusts a GAAP measure – cash flow provided by operating activities – for changes in non-cash working capital, which management uses to analyze operating performance and liquidity. Changes to non-cash working capital can include, among other factors, the timing of offshore feedstock purchases and payments for fuel and income taxes, which management believes reduces comparability between periods.

Year ended December 31 ($ millions)	Oil Sands			Exploration and Production			Refining and Marketing		
	2012	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Net earnings (loss)	**458**	2 603	1 520	**138**	306	1 938	**2 129**	1 726	819
Adjustments for:									
Depreciation, depletion, amortization and impairment	**3 964**	1 374	1 310	**1 857**	2 035	1 978	**468**	444	440
Deferred income taxes	**266**	895	487	**28**	354	196	**529**	494	269
Accretion of liabilities	**109**	85	130	**62**	69	103	**4**	3	2
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**—**	—	—	**—**	—	—	**—**	—	—
Change in fair value of derivative contracts	**—**	—	(316)	**—**	—	—	**(1)**	3	—
(Gain) loss on disposal of assets	**(29)**	122	14	**(1)**	31	(998)	**(13)**	(16)	(30)
Share-based compensation	**95**	(35)	55	**14**	(4)	24	**48**	(21)	39
Exploration expenses	**—**	—	—	**145**	28	96	**—**	—	—
Settlement of decommissioning and restoration liabilities	**(380)**	(458)	(375)	**(32)**	(19)	(23)	**(21)**	(19)	(19)
Other	**(76)**	(14)	(48)	**16**	46	11	**7**	(40)	18
Cash flow from (used in) operations	**4 407**	4 572	2 777	**2 227**	2 846	3 325	**3 150**	2 574	1 538
(Increase) decrease in non-cash working capital	**(781)**	(676)	(890)	**(205)**	398	(320)	**(485)**	600	(260)
Cash flow provided by (used in) operating activities	**3 626**	3 896	1 887	**2 022**	3 244	3 005	**2 665**	3 174	1 278

Year ended December 31 ($ millions)	Corporate, Energy Trading and Eliminations			Total		
	2012	2011	2010	**2012**	2011	2010
Net earnings (loss)	**58**	(331)	(448)	**2 783**	4 304	3 829
Adjustments for:						
Depreciation, depletion, amortization and impairment	**161**	99	75	**6 450**	3 952	3 803
Deferred income taxes	**(80)**	(99)	(201)	**743**	1 644	751
Accretion of liabilities	**7**	—	—	**182**	157	235
Unrealized foreign exchange (gain) loss on U.S. dollar denominated long-term debt	**(181)**	183	(426)	**(181)**	183	(426)
Change in fair value of derivative contracts	**11**	(43)	31	**10**	(40)	(285)
(Gain) loss on disposal of assets	**(1)**	(1)	39	**(44)**	136	(975)
Share-based compensation	**57**	(42)	(5)	**214**	(102)	113
Exploration expenses	**—**	—	—	**145**	28	96
Settlement of decommissioning and restoration liabilities	**—**	—	—	**(433)**	(496)	(417)
Other	**(71)**	(12)	(49)	**(124)**	(20)	(68)
Cash flow from (used in) operations	**(39)**	(246)	(984)	**9 745**	9 746	6 656
Decrease (increase) in non-cash working capital	**572**	(80)	300	**(899)**	242	(1 170)
Cash flow provided by (used in) operating activities	**533**	(326)	(684)	**8 846**	9 988	5 486

The following is a reconciliation of cash flow from operations for Suncor's last five years of operations. Cash flow from operations for 2008 and 2009 are reported under Previous GAAP.

($ millions)	**2012**	2011	2010	2009	2008
Cash flow provided by operating activities	**8 846**	9 988	5 486	2 575	4 462
Increase (decrease) in non-cash working capital	**899**	(242)	1 170	224	(405)
Cash flow from operations	**9 745**	9 746	6 656	2 799	4 057

Oil Sands Cash Operating Costs

Oil Sands cash operating costs and cash operating costs per barrel are non-GAAP financial measures, which are derived by adjusting Oil Sands segment operating, selling and general expense (a GAAP measure based on sales volumes) for i) costs pertaining to Syncrude operations; ii) non-production costs that management believes do not relate to the production performance of Oil Sands operations, including, but not limited to, share-based compensation adjustments, costs related to the remobilization or deferral of growth projects, research, the expense recorded as part of a non-monetary arrangement involving a third-party processor, and feedstock costs for natural gas used to create hydrogen for secondary upgrading processes; iii) excess power generated and sold that is recorded in operating revenue; and iv) the impacts of changes in inventory levels, such that the company is able to present cost information based on production volumes.

Year ended December 31 ($ millions)	**2012**	2011	2010
Operating, selling and general expense	**5 375**	5 169	4 537
Syncrude operating, selling and general expense	**(513)**	(529)	(473)
Non-production costs [1]	**(338)**	(275)	(305)
Other [2]	**(129)**	(10)	32
Cash operating costs	**4 395**	4 355	3 791
Cash operating costs ($/bbl)	**37.05**	39.05	36.70

(1) Significant non-production costs include, but are not limited to, share-based compensation adjustments, costs related to the remobilization or deferral of growth projects, research, the expense recorded as part of a non-monetary arrangement involving a third-party processor and feedstock costs for natural gas used to create hydrogen for secondary upgrading processes.

(2) Other includes the impacts of changes in inventory valuation and operating revenues associated with excess power from cogeneration units.

Effective 2012, the calculation of Oil Sands cash operating costs has been updated to better reflect the ongoing cash cost of production, and prior period figures have been redetermined. The cost of natural gas feedstock for secondary upgrading processes, the cost of diluent purchased for transportation of product to markets, and non-cash costs related to the accretion of liabilities for decommissioning and restoration provisions are no longer included in cash operating costs. Certain cash costs relating to safety programs, which were previously considered non-production costs, are now included in cash operating costs. The following table reconciles amounts previously reported to those presented in this MD&A:

Year ended December 31 ($ millions)	**2011**	2010
Cash operating costs, as previously reported	4 479	3 990
Elements added to cash operating costs definition:		
Safety programs	33	18
Elements removed from cash operating costs definition:		
Natural gas feedstock for secondary upgrading processes	(53)	(49)
Accretion of liabilities	(64)	(93)
Purchased diluent	(40)	(75)
Cash operating costs, as restated in this MD&A	4 355	3 791
Cash operating costs, as previously reported ($/bbl)	40.20	38.65
Cash operating costs, as restated in this MD&A ($/bbl)	39.05	36.70

Impact of First-in, First-out Inventory Valuation on Refining and Marketing Net Earnings

GAAP requires the use of a first-in, first-out inventory (FIFO) valuation methodology. For Suncor, this results in a disconnect between the sales prices for refined products, which reflect current market conditions, and the amount recorded as the cost of sale for the related refinery feedstock, which reflect market conditions at the time when the feedstock was purchased. This lag between purchase and sale can be anywhere from several weeks to several months, and is influenced by the time to receive crude after purchase (which can be several weeks for foreign offshore crude purchases), regional crude inventory levels, the completion of refining processes, transportation time to distribution channels, and regional refined product inventory levels.

Suncor prepares and presents an estimate of the impact of using a FIFO inventory valuation methodology compared to a last-in, first-out (LIFO) methodology, because management uses the information to analyze operating performance and

compare itself against refining peers that are permitted to use LIFO inventory valuation under United States GAAP (U.S. GAAP).

Generally, during times of increasing crude prices, a FIFO inventory valuation positively impacts net earnings, compared with LIFO inventory valuation, as inventories purchased during periods of lower relative feedstock costs are replaced by inventories purchased during periods of higher relative feedstock costs. Conversely, during times of decreasing crude prices, FIFO inventory valuation generally negatively impacts net earnings, compared with LIFO inventory valuation, as inventories purchased during periods of higher relative feedstock costs are replaced by inventories purchased during periods of lower relative feedstock costs.

The company's estimate of the impact of using a FIFO inventory valuation methodology compared to a LIFO methodology is a relatively simple calculation that replaces the FIFO-based costs of goods sold with an average purchase cost over the same period, and does not incorporate all of the elements of a more complex and precise LIFO inventory valuation methodology that an entity using U.S. GAAP might include. The company's estimate is not derived from a standardized calculation and, therefore, is unlikely to be comparable to similar measures presented by other companies, and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP or U.S. GAAP.

14. ADVISORY – FORWARD-LOOKING INFORMATION

The MD&A 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 MD&A include references to:

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

- *Production at Firebag will reach 180,000 bbls/d over the next year;*
- *The MNU will increase sweet SCO production capacity by approximately 10% and stabilize secondary upgrading processes by providing flexibility during maintenance;*
- *Production capacity at Hebron will be 150,000 bbls/d with first oil late in 2017;*
- *There will be an increase of gross installed capacity of 140 MW from the Adelaide and Cedar Point wind projects and an increase of production to 38,000 bbls/d by 2015 at the MacKay River central processing facility;*
- *First oil from newly steamed wells at Mackay River will occur in the first quarter of 2013; and*
- *Golden Eagle will achieve first oil in late 2014 or early 2015.*

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

- *The refurbishment of the Upgrader 1 hydrogen plant will take place late in the first quarter of 2013, and is expected to be offline for approximately 14 weeks;*
- *The decrease in sweet SCO production during the refurbishment of the Upgrader 1 hydrogen plant will be partially offset by the additional hydrotreating capacity from the MNU;*
- *The maintenance event for the Upgrader 1 facility will take place in the second quarter of 2013, and is scheduled for approximately seven weeks, and that, within this outage, Suncor anticipates no production from Upgrader 1;*
- *Suncor will complete maintenance at one of the Firebag central processing facilities during the maintenance of the Upgrader 1 facility;*
- *Maintenance will take place in the third quarter of 2013 for Suncor's Upgrader 2 facilities, which is anticipated to have an impact on SCO production;*
- *The commissioning of the third drill centre at Terra Nova will take place in the third quarter of 2013;*
- *Routine annual maintenance will take place for Terra Nova, White Rose and Buzzard in the second and third quarters of 2013;*
- *Maintenance events at the Edmonton refinery on the heavy sour crude train will occur in the second quarter of 2013 for an expected duration of five weeks and on the sweet synthetic crude unit in the third quarter of 2013 for an expected duration of two weeks; and*
- *Maintenance at the Sarnia refinery for one of its crude units will take place in the third quarter of 2013 for an expected duration of six weeks.*

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

- *Suncor's belief that Firebag Stage 4 will come in approximately 15% below the announced cost estimate of $2.0 billion;*

- *Growth capital for 2013 will be focused on high return projects;*
- *Growth capital in Refining and Marketing will be focused on projects to prepare the Montreal refinery to receive shipments of western crude feedstock;*
- *Sanctioning of the Fort Hills mining project will occur in the second half of 2013, and, if sanctioned and subject to approval, post sanction development activities will commence, including detailed engineering design, bulk equipment and material procurement and site construction;*
- *The first two of four new storage tanks in Hardisty, Alberta will be connected to the Enbridge Mainline system in 2013;*
- *The completion of an insulated pipeline to allow transport of bitumen without the requirement for additional diluent between Firebag and the company's Athabasca terminal starting in the second quarter of 2013;*
- *The acquisition of new seismic data in 2013 and appraisal drilling in 2014 at the Beta discovery;*
- *Cost estimates, target completion dates and project details provided in the Significant Growth Projects Update and Other Capital Projects sections of the MD&A; and*
- *Plans to leverage and extend the production life of existing offshore infrastructure, with drilling activities in areas adjacent to producing fields, such as the Hibernia Extension, the White Rose Extensions, and the Northern Terrace area for Buzzard.*

Suncor's strategy for 2013, including:

- *Suncor's plans to continue redevelopment of existing fields in Libya and resume exploration activities in the country;*
- *Plans for Suncor to focus on optimization of its current asset base in the Oil Sands through the development of new infrastructure that will enhance regional takeaway capacity and marketing flexibility in 2013, and debottlenecking projects that are expected to provide low cost efficiencies and higher outputs in Oil Sands operations;*
- *The company's portfolio of in situ technology projects, which is expected to drive improvements and efficiencies in current production and develop future opportunities, and the focus of this portfolio on subsurface and surface challenges;*
- *Operational excellence initiatives will continuously improve Suncor's plant utilization and workforce productivity in 2013;*
- *A decision being made on the Voyageur project by the end of the first quarter of 2013; and*
- *Suncor will focus in 2013 on bringing the Montreal refinery into the inland refining network, and plans to transport western crudes via rail to the refinery.*

Also:

- *The plan for Suncor to pursue opportunities to divest non-core properties in its North American Onshore operations that meet its financial objectives;*
- *Increased competition and fluctuating demand in key retail markets for Suncor's Refining and Marketing business is expected to be offset by growth in wholesale channels;*
- *The company's assessment in respect of the proposal letter received from the CRA relating to the income tax treatment of realized losses in 2007 on the settlement of certain derivative contracts relating to Buzzard and the company's belief that 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 action;*
- *The company's assessment of asset impairment in Syria, including the amounts recorded as impairment charges in 2012 and the carrying value of such assets as at December 31, 2012;*
- *The company's assessment of the situation in Libya, including the amounts recorded as impairment charges in 2011;*
- *Management's belief that Suncor will have the capital resources to fund its planned 2013 capital spending program of $7.3 billion and to meet current and long-term working capital requirements through existing cash balances and short-term investments, cash flow from operations, available committed credit facilities, issuing commercial paper, and issuing long-term notes or debentures, and that, if additional capital is required, adequate additional financing will be available to Suncor in the debt capital markets at commercial terms and rates;*
- *Management's belief that a phased and flexible approach to existing and future growth projects should assist Suncor in maintaining its ability to manage project costs and debt levels;*
- *The company's expectations that the maximum weighted average term to maturity of its short-term*

investment portfolio will not exceed six months, and that all investments will be with counterparties with investment grade debt ratings; and

- *The company's belief that it does not have any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on the company's financial condition or financial performance, including liquidity and capital resources.*

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 MD&A, including under the heading Risk Factors, and the company's 2012 AIF dated March 1, 2013 and Form 40-F on file with Canadian securities commissions at www.sedar.com and the United States Securities and Exchange Commission at www.sec.gov. Readers are also referred to the risk factors and assumptions described in other documents that Suncor files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the company.

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EXHIBIT 99-2

Management's Discussion and Analysis for the fiscal year ended December 31, 2012, dated February 26, 2013

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EXHIBIT 99-3

Consent of PricewaterhouseCoopers LLP

CONSENT OF INDEPENDENT AUDITOR

We hereby consent to inclusion in this Annual Report on Form 40-F for the year ended December 31, 2012 and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029) and Form F-9 (File No. 333-181421) of Suncor Energy Inc., of our report dated February 26, 2013 relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in the Annual Report.

We also consent to the reference to us under the heading "Interests of Experts" in the Annual Information Form incorporated by reference in this Annual Report on Form 40-F which is incorporated by reference in the Registration Statements referred to above.

"PricewaterhouseCoopers LLP"
Chartered Accountants
Calgary, Alberta
March 1, 2013

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EXHIBIT 99-3

Consent of PricewaterhouseCoopers LLP
CONSENT OF INDEPENDENT AUDITOR

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EXHIBIT 99-4

Consent of GLJ Petroleum Consultants Ltd.

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces of Canada

Dear Sirs

Re: Suncor Energy Inc.

We refer to the following reports (the "**Reports**") prepared by GLJ Petroleum Consultants Ltd. ("**GLJ**"):

- Reserves Assessment and Evaluation of In Situ Oil Sands Properties — Summary; and
- Reserves Evaluation and Resources Assessment of Oil Sands Mining Properties — Summary

which provide GLJ's reports on proved and probable reserves evaluations and assessment of contingent resource pursuant to Canadian disclosure requirements of Suncor Energy Inc.'s Canadian mining and in-situ leases that were evaluated as at December 31, 2012.

We hereby consent to the use of our name, reference to and excerpts and information derived from the said Reports by Suncor Energy Inc. in its:

1. Annual Report on Form 40-F for the year ended December 31, 2012 (the "**Form 40-F**") and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029) and Form F-9 (File No. 333-181421) of Suncor Energy Inc., of our Reports;
2. 2012 Annual Report for the year ended December 31, 2012 (the "**Annual Report**") to be filed with the securities regulatory authorities of each of the provinces of Canada; and
3. Annual Information Form dated March 1, 2013 (the "**AIF**"), which is incorporated by reference into the following prospectuses (collectively, the "**Prospectuses**"): (i) the short form base shelf prospectus of Suncor dated May 25, 2012 relating to the sale and issue of debt securities from time to time in the aggregate principal amount of U.S. $2,000,000,000, and (ii) the short form base shelf prospectus of Suncor dated May 25, 2012 relating to the sale and issue of Series 5 medium term notes, from time to time, in the aggregate principal amount of up to CDN $2,000,000,000.

We have read the Form 40-F, Annual Report, AIF and Prospectuses and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Reports or that are within our knowledge as a result of the services which we performed in connection with the Reports.

Yours very truly,

GLJ PETROLEUM CONSULTANTS LTD.

"GLJ Petroleum Consultants Ltd."

Caralyn P. Bennett, P. Eng.
Vice-President

Dated: March 1, 2013
Calgary, Alberta
CANADA

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EXHIBIT 99-4

Consent of GLJ Petroleum Consultants Ltd.
LETTER OF CONSENT

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EXHIBIT 99-5

Consent of Sproule Associates Limited, Sproule Unconventional Limited and Sproule International Limited

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces of Canada

Dear Sirs:

Re: Suncor Energy Inc.

We refer to the following reports (the "**Reports**") prepared by Sproule Associates Limited, Sproule Unconventional Limited and Sproule International Limited:

- Evaluation of the P&NG Reserves of Suncor Energy Inc. in the Newfoundland Offshore Areas (As of December 31, 2012);
- Evaluation of the P&NG Reserves of Suncor Energy Inc. in the North America Onshore Properties (As of December 31, 2012);
- Assessment of the P&NG Resources of Suncor Energy Inc. in the Montney Formation, Kobes Area, British Columbia (As of June 30, 2012) ("**Kobes Resource Assessment**");
- Evaluation of the P&NG Reserves of Suncor Energy Inc., North Sea Properties (As of December 31, 2012);
- Evaluation of the P&NG Reserves of Suncor Energy Inc., Other International Properties (As of December 31, 2012); and
- Evaluation of the P&NG Reserves of Suncor Energy Inc., Other International Properties, Volume 3 — Ash Shaer Field, Syria (As of December 31, 2011) ("**Syria Reserves Assessment**").

which provide our reports on proved and probable reserves evaluations and assessment of contingent resource pursuant to Canadian disclosure requirements of Suncor Energy Inc.'s Canadian onshore and offshore conventional assets and international operations that were evaluated as at December 31, 2012, except in the case of: (i) the Kobes Resource Assessment, which is as at June 30, 2012; (ii) the Syria Reserves Assessment, which is as at December 31, 2011.

We hereby consent to the use of our name, reference to and excerpts and information derived from the said Reports by Suncor Energy Inc. in its:

1. Annual Report on Form 40-F for the year ended December 31, 2012 (the " **Form 40-F**") and the incorporation by reference in the registration statements on Form S-8 (File No. 333-87604), Form S-8 (File No. 333-112234), Form S-8 (File No. 333-118648), Form S-8 (File No. 333-124415), Form S-8 (File No. 333-149532), Form S-8 (File No. 333-161021), Form S-8 (File No. 333-161029) and Form F-9 (File No. 333-181421) of Suncor Energy Inc., of our Reports;

2. 2012 Annual Report for the year ended December 31, 2012 (the " **Annual Report**") to be filed with the securities regulatory authorities of each of the provinces of Canada; and

3. Annual Information Form dated March 1, 2013 (the " **AIF**"), which is incorporated by reference into the following prospectuses (collectively, the "**Prospectuses**"): (i) the short form base shelf prospectus of Suncor dated May 25, 2012 relating to the sale and issue of debt securities from time to time in the aggregate principal amount of U.S. $2,000,000,000, and (ii) the short form base shelf prospectus of Suncor dated May 25, 2012 relating to the sale and issue of Series 5 medium term notes, from time to time, in the aggregate principal amount of up to CDN $2,000,000,000.

We have read the Form 40-F, Annual Report, AIF and Prospectuses and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from our Reports

or that are within our knowledge as a result of the services which we performed in connection with the Reports.

Sincerely,

Sproule Associates Limited,
Sproule Unconventional Limited and
Sproule International Limited

"Sproule Associates Limited",
"Sproule Unconventional Limited" and
"Sproule International Limited"

Harry J. Helwerda, P.Eng., FEC
Executive Vice President and Director

Dated: March 1, 2013
Calgary, Alberta, Canada

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EXHIBIT 99-5

Consent of Sproule Associates Limited, Sproule Unconventional Limited and Sproule International Limited
LETTER OF CONSENT

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EXHIBIT 99-6

CERTIFICATION

I, Steven W. Williams, certify that:

1. I have reviewed this annual report on Form 40-F of Suncor Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ STEVEN W. WILLIAMS

Steven W. Williams
President and Chief Executive Officer

DATE: March 1, 2013

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EXHIBIT 99-6

CERTIFICATION

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EXHIBIT 99-7

CERTIFICATION

I, BART W. DEMOSKY, certify that:

1. I have reviewed this annual report on Form 40-F of Suncor Energy Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ BART W. DEMOSKY

Bart W. Demosky
Chief Financial Officer

DATE: March 1, 2013

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EXHIBIT 99-7

CERTIFICATION

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EXHIBIT 99-8

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, STEVEN W. WILLIAMS, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ STEVEN W. WILLIAMS

Steven W. Williams
President and Chief Executive Officer
Suncor Energy Inc.

DATE: March 1, 2013

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EXHIBIT 99-8

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

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EXHIBIT 99-9

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Suncor Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, BART W. DEMOSKY, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ BART W. DEMOSKY

Bart W. Demosky
Chief Financial Officer
Suncor Energy Inc.

DATE: March 1, 2013

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EXHIBIT 99-9

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002