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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, 2013
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, 2013 there were 1,478,315,069 Common Shares issued and outstanding**
Preferred Shares	**None**

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

Yes ý No o

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

Yes o No o

INCORPORATION BY REFERENCE

The Registrant's Annual Information Form dated February 28, 2014, 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, 2013, 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 February 28, 2014



ANNUAL INFORMATION FORM DATED FEBRUARY 28, 2014

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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.

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 2013 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, 2013. References to our MD&A mean Suncor's Management's Discussion and Analysis, dated February 24, 2014.

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. Yields of SCO from Suncor's upgrading processes are approximately 80% of bitumen feedstock input, and may vary depending on the source of bitumen. 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**.
- **Unconventional crude oil** is crude oil produced using techniques other than by standard industry recovery methods.
- **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.

- **Associated gas** is the gas cap that overlays a crude oil accumulation in a reservoir.
- **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.
- **Solution gas** is natural gas that is dissolved in crude oil in the reservoir at original reservoir conditions and that is normally produced with the crude oil.

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. **Liquefied petroleum gas (LPG)** includes propane and/or butane.

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.

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.

Infill wells are drilled between existing development wells to target regions of the reservoir containing bypassed hydrocarbon or to accelerate production.

Observation wells are used to monitor changes in a producing field. Parameters being monitored include fluid saturations and reservoir pressure.

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

Sidetrack wells are secondary wellbores drilled away from an original wellbore. These enable the bypass of an unusable section of the original wellbore or allow for exploration of a nearby geological feature.

Stratigraphic wells are 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** or **delineation wells** 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.

Debottleneck refers to the process of increasing the production capacity of existing facilities through modification of existing equipment to remove throughput restrictions or inefficiencies.

Downstream refers to the refining of 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 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. Overburden is removed before mining and on an ongoing basis to expose ore.

Production sharing contracts (PSC) are a common type of contract, outside North America, 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. The resource extraction company does not obtain title to the product; however, the company is subject to the upstream risks and rewards. 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, 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 extracted.

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.

Tailings Reduction Operations (TRO™) is a process involving rapidly converting fluid fine tailings into a solid landscape suitable for reclamation. In this process, mature fine tailings are mixed with a polymer flocculent and deposited in thin layers over sand beaches with 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.

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

Conversion Table[1][2]

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

1 tonne = 0.984 tons (long)
1 tonne = 1.102 tons (short)
1 kilometre = 0.62 miles
1 hectare = 2.5 acres

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

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

CORPORATE STRUCTURE

Name and Incorporation

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

Pursuant to an 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 the *Canada Business Corporations Act*.

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, 2013 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 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 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 our 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 refining operations.
Suncor Energy (U.S.A.) Inc.	U.S.	A subsidiary of Suncor Energy (U.S.A.) Holdings Inc. through which our U.S. refining and marketing operations are conducted.

International operations

3908968 Canada Inc.	Canada	A subsidiary of Suncor Energy Inc. that holds certain of our international interests.
Suncor Energy UK Holdings Ltd.	U.K.	A subsidiary of 3908968 Canada Inc. that holds certain of our U.K. interests.
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.
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, 2013, and (ii) less than 10% of the company's consolidated operating revenues for the fiscal year ended December 31, 2013. 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; we transport and refine crude oil, and we 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 either upgrades this production into SCO for refinery feedstock and diesel fuel, or blends the bitumen with diluent for direct sale to market. The Oil Sands segment includes:

- **Oil Sands Operations** refer to Suncor's wholly-owned and operated mining, extraction, upgrading, in situ and related logistics and storage 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, cogeneration units and hot bitumen infrastructure, including an insulated pipeline, diluent import capabilities and a cooling and blending facility, and related storage assets. In Situ production is either upgraded by Oil Sands Base or blended with diluent and marketed directly to customers.

- The Oil Sands segment also includes the company's interests in significant growth projects, including its 40.8% interest in the **Fort Hills** mining project where Suncor is the operator and its 36.8% interest in the **Joslyn** North mining project. The company also holds a 12.0% interest in the **Syncrude** oil sands mining and upgrading operation (these assets were formerly known as Oil Sands Ventures prior to an internal reorganization effective January 1, 2014).

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% 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 projects are located in the U.K. sector of the North Sea and 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. As at the date hereof, production in Libya is shut-in due to political unrest. 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 political 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 working interests in unconventional natural gas and crude oil assets in Western Canada, including unconventional oil and natural gas properties in central Alberta and northeast B.C.

REFINING AND MARKETING

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

- **Refining and 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 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 product between the company's segments and the provision of insurance for a portion of the company's operations by the Corporate captive insurance entity.

Three-Year History

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 when the country transitioned to a new government, and the operator was able to restart production from all major producing fields in the first quarter of 2012. Production has since been suspended again due to the closure of export terminal operations at eastern Libyan seaports as a result of political unrest that began earlier in 2013.

- **Successful completion of the Upgrader 2 turnaround.** During the second quarter, the company completed the largest turnaround at its Upgrader 2 facilities in the company's history.

- **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. During 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.

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 commissioned.** Suncor completed installation of its tailings management assets. 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 to 104 mbbls/d, approximately 75% higher than the 2011 production level. 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.

- **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 MNU has increased sweet SCO production capacity, primarily through a naphtha hydrotreating unit, and stabilized secondary upgrading processes by providing flexibility with respect to hydrogen production during planned or unplanned maintenance.

- **Oil Sands logistics infrastructure brought into service.** 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 four storage tanks in Hardisty, Alberta, which are connected to the Enbridge mainline pipeline.

- **Hebron project receives sanction.** In December, the co-owners of the Hebron project located offshore Newfoundland and Labrador sanctioned a 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 mbbls/d.

2013

- **Voyageur oil sands upgrader project not proceeding.** In March, Suncor announced its intention not to proceed with the Voyageur upgrader project in response to changed market conditions that challenged the project economics. Suncor acquired Total E&P Canada Ltd's (Total E&P) interest in the Voyageur Upgrader Limited Partnership (VULP) for $515 million to gain full control of the partnership's assets, including a hot bitumen blending facility and tankage used to support the company's growing Oil Sands Operations.

- **Majority of conventional natural gas business in Western Canada sold.** Suncor sold its conventional natural gas business in Western Canada with an effective date of January 1, 2013. The transaction closed September 26, 2013 for gross proceeds of $1 billion, before closing adjustments and other closing costs. The sale included properties situated across multiple regions in Alberta, northeast British Columbia and southern Saskatchewan but excluded the majority of Suncor's unconventional natural gas properties in the Kobes region (Montney formation) of northeast British Columbia and unconventional oil properties in the Wilson Creek area (Cardium formation) of central Alberta.

- **Suncor constructs wetland.** A reclamation milestone was reached with the planting of a fen wetland at Oil Sands Base. A fen is a specific type of peat-accumulating wetland. Suncor is one of the first companies in the world to attempt reconstruction of this type of wetland. Construction of the fen's underlying watershed was completed in January 2013, and vegetation was planted during the spring and summer.

- **Firebag ramp-up completed.** Firebag production in 2013 increased by approximately 40% over 2012 production levels as Stage 4 ramp-up was completed. The complex ended 2013 achieving daily production rates of approximately 95% of nameplate capacity of 180 mbbls/d.

- **Hot bitumen infrastructure commissioned.** Suncor initiated a number of debottlenecking projects across Oil Sands Operations, including the completion of an insulated bitumen pipeline from Firebag to the Athabasca terminal. Combined with blending facilities at the Athabasca terminal and diluent import capabilities, Suncor increased the takeaway capacity of bitumen and unlocked production in mining.

- **Fort Hills project sanctioned.** In October, Suncor and project co-owners agreed unanimously to proceed with the Fort Hills oil sands mining project. The project is scheduled to produce first oil by the fourth quarter of 2017 and is expected to achieve 90% of its planned production capacity of 180 mbbls/d (73 mbbls/d net to Suncor) within its first year.

- **Libya production shut in.** Export terminal operations at Libyan seaports were closed during the latter half of 2013 due to political unrest in the country. Production was shut in during this period; however, Suncor was able to continue progress on its exploration program.

- **Rail offloading facility complete.** Construction of a rail offloading facility to enable receipt of inland crudes at the Montreal refinery was completed in the fourth quarter of 2013. The Montreal refinery received its first shipment in early December with volumes expected to increase to approximately 35 mbbls/d in the first quarter of 2014.

- **Successful completion of Upgrader 1 turnaround.** Suncor successfully executed planned maintenance across its operations, including a seven-week turnaround at Upgrader 1, which was the largest turnaround in the company's history. The next scheduled turnaround at Oil Sands Operations is not until 2016.

NARRATIVE DESCRIPTION OF SUNCOR'S BUSINESSES

Oil Sands

For a discussion of the 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 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. Coarse tailings produced in this process are placed directly into mine sand dump areas.

- **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 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. Production however, is impacted during the turnaround cycle. Planned maintenance events generally occur on routine cycles, determined by historical operating performance, recommended usage factors or regulatory requirements. A turnaround typically involves shutting down the unit, inspecting it for wear or other damage, repairing or replacing components, and then restarting the unit.

- **Reclamation**

  Mining processes disturb areas of land that must be reclaimed. Land reclamation activities involve 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$_{TM}$. 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 2013, the company mined approximately 151 million tonnes of bitumen ore (2012 – 151 million tonnes). During 2013, Suncor processed an average of 270 mbbls/d of mined bitumen in its extraction facilities (2012 – 266 mbbls/d).

Upgrading

Suncor's upgrading facilities consist of two upgraders – Upgrader 1, which has a primary upgrading capacity of approximately 110 mbbls/d of SCO, and Upgrader 2, which has a primary upgrading capacity of approximately 240 mbbls/d of SCO. Suncor's secondary upgrading facilities consist of three hydrogen plants, three naphtha hydrotreaters, two gas oil hydrotreaters, one diesel hydrotreater and one kero hydrotreater.

During 2013, Suncor averaged 283 mbbls/d of upgraded (SCO and diesel) production, sourced from bitumen

provided by both mining and extraction and in situ operations.

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. Suncor undertakes exploratory drilling programs on such leases from time-to-time, as part of its mine replacement projects. Suncor holds a 100% working interest in both Voyageur South and Audet.

The Voyageur South project is in the early stages of planning and the development timing for the project is currently under assessment. Development options are currently being prepared for review in 2014.

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 blend diluent with the bitumen, or transport it on an insulated pipeline as hot bitumen. The bitumen is either upgraded at Oil Sands Base upgrading facilities or blended with internally produced or imported diluent, and sold directly to market.

- **Power and steam generation**

  Once Through Steam Generators (OTSGs) are powered by both natural gas and gas vapours recovered at central processing facilities. 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. Suncor's Firebag complex consists of four central processing facilities with total bitumen processing capacity of approximately 180 mbbls/d. Actual production from Firebag varies based on steaming and ramp-up periods for new wells, planned and unplanned maintenance, reservoir conditions and other factors.

As at December 31, 2013, Firebag had nine well pads in operation with 119 SAGD well pairs and 18 infill wells either producing or on initial steam injection. Central processing facilities have been designed to be flexible as to which well pads supply bitumen. Steam generated at the various facilities can be used at multiple well pads. In addition, Firebag includes five cogeneration units that generate steam, which are capable of producing 425 MW of electricity made up of Firebag site power load of 110 MW and exports of 315 MW. There are also 13 OTSGs at the site for additional steam generation.

As of December 31, 2013, the cumulative SOR at Firebag was 3.3 (2012 – 3.4).

MacKay River

Production from MacKay River commenced in 2002. As at December 31, 2013, MacKay River included six well pads with 74 well pairs either producing or on initial steam injection. The MacKay River central processing facilities have bitumen processing capacity of approximately 30 mbbls/d. A third party owns the on-site cogeneration unit that is used to generate steam and electricity which Suncor operates under a commercial agreement. There are also four OTSGs at the site for additional steam generation. The company has commenced a debottlenecking project of existing central processing facilities that is expected to

increase existing bitumen processing capacity to approximately 38 mbbls/d by 2015.

As at December 31, 2013, the cumulative SOR at MacKay River was 2.6 (2012 – 2.5).

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 an additional central processing facility. Suncor continues to work towards a 2014 sanction decision of an additional central processing facility at MacKay River, which is targeted to have an initial design capacity of approximately 20 mbbls/d and first oil in 2017.

Other In Situ Leases

Suncor owns several other oil sands leases, including those known as Meadow Creek, Lewis, Chard and Kirby. Suncor believes these leases can be developed using in situ techniques on which it may undertake exploratory drilling. In 2013, Suncor drilled 50 core holes at Lewis and 66 gross core holes at Meadow Creek. Plans for winter 2014 drilling include an additional 55 core holes at Lewis and 37 core holes at Meadow Creek. Suncor holds a 100% working interest in Lewis and a 75% working interest in Meadow Creek.

Starting with Meadow Creek, Suncor is commencing a greenfield growth plan with a concept to grow new In Situ reservoirs using a replication strategy to build standardized surface facilities, well pads and infrastructure on a program basis. The winter exploratory drilling programs are designed to identify sufficient resources to fill facilities associated with the replication strategy.

Oil Sands Joint Arrangements

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, the Syncrude co-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 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, certain aspects of the 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 2013, Suncor's share of Syncrude production averaged 32 mbbls/d (2012 – 34 mbbls/d).

Fort Hills

Fort Hills is an oil sands mining area comprising leases on the east side of the Athabasca River, north of Oil Sands Base operations. Designs for the Fort Hills mining project plan for 180 mbbls/d of bitumen production (gross). Suncor originally acquired a 60% working interest in Fort Hills through the merger with Petro-Canada, but disposed 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 is the contract operator for the Fort Hills project. The company's share of the post-sanction project costs are estimated to be $5.5 billion. Approximately 15% of the company's 2014 capital budget has been allocated to this project. Project activities in 2014 are expected to focus on detailed engineering, procurement and ramp-up of field construction activities.

Other Assets

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 157 mbbls/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 plans to provide an update on the targeted timing for a sanction decision on the Joslyn project when available.

New Technology

Technology is a fundamental component to Suncor's business. Suncor has pioneered commercial oil sands development and continues to advance technology through innovation and collaboration to improve efficiencies, lower costs and increase environmental performance.

Suncor is working on several new in situ technology projects that are proceeding with the next phase of field testing. Examples of Suncor's new technology projects include:

- Electric Submersible Pumps (ESPs) – Suncor is working with vendors on technology to improve equipment performance in SAGD.
- N-SOLV$_{TM}$ – Evolving toward waterless recovery by using a warm solvent to extract bitumen efficiently, sustainably and economically.
- Steam Assisted Gravity Drainage Less Intensive Technology Enhanced (SAGD LITE) – Field trials are underway to evaluate technologies such as solvent addition, surfactant addition, flow control devices and injection control devices to improve cost, SORs, and timely recovery and productivity.

Suncor is a member of Canada's Oil Sands Innovation Alliance (COSIA) which is a group of oil sands producers brought together to accelerate environmental performance improvement through collaboration.

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. Commencing in 2014, production is also being sold to markets in the U.S. Gulf Coast. 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 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. During 2013, approximately 55% or 94 mbbls/d (2012 – 63% or 83 mbbls/d) of In Situ bitumen production was processed by Oil Sands Base upgrading facilities.

	2013		2012	
Sales Volumes and Operating Revenues – Principal Products	**mbbls/d**	**% operating revenues**	mbbls/d	% operating revenues
Sweet – Light sweet SCO and diesel (including Syncrude)	**147.9**	**43**	152.7	47
Sour – Light sour SCO and bitumen	**241.9**	**51**	205.6	48
Non-proprietary, byproducts and other operating revenues [(1)]	**n/a**	**6**	n/a	5
	389.8		358.3	

(1) Operating revenues include sales of non-proprietary volumes, primarily third-party diluent purchased to support sales of bitumen that is required when the company is unable to meet diluent demands internally, as well as revenues associated with excess power from cogeneration units.

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:

- 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.
- To Cheecham, Alberta, on the Enbridge Athabasca Pipeline or the Enbridge Wood Buffalo Pipeline. From Cheecham, the Enbridge Athabasca Pipeline continues to Hardisty, Alberta.
- To 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:

- To 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.
- To Suncor's Sarnia refinery on the Enbridge Mainline and Lakehead systems.
- Through the Enbridge Mainline system, crude can reach most major refining hubs via the Enbridge Mainline, Express/Platte and Keystone pipeline systems.

Commencing in 2014, Suncor has begun shipping heavy crude on TransCanada's Gulf Coast Pipeline, providing the company with more than 50 mbbls/d of heavy crude shipping capacity to the U.S. Gulf Coast and another outlet for the growing bitumen production at Firebag.

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 accessible by air and private road.

Royalty Agreements

Oil Sands Base and Syncrude

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 in 2008.

As part of the New Royalty Framework, Suncor 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. 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 2013, Suncor incurred royalties at Oil Sands Base mining operations at a rate of 30% of R – C (2012 – 30% of R – C).

In 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 2013, the royalty rate was 25% of net revenue (2012 – 25%). As part of its agreement, Syncrude also exercised its option to transition to a bitumen-based royalty from an SCO-based royalty. 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 the BVM Regulations effective January 1, 2009 to determine the value of bitumen for royalty purposes. The Crown notified Suncor that the BVM Regulation 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 the modifications to the Suncor BVM, providing for bitumen quality adjustments not previously recognized and adjustments for transportation.

With respect to the bitumen quality adjustments, Suncor filed a Notice of Commencement of Arbitration with the Alberta government on January 29, 2011 pursuant to the dispute resolution provisions of the Suncor RAA. In December 2013, Suncor reached an agreement with the Alberta government to settle all unresolved royalty issues under the Suncor RAA.

The co-owners of Syncrude also filed a non-compliance notice with the Alberta government, citing that reasonable adjustments in the determination of the bitumen value were not considered by the government. In December 2013, the Syncrude co-owners reached an agreement with the Alberta government to settle unresolved royalty issues under the Syncrude RAA.

Under these modified settlement agreements, certain provisions of the BVM Regulation, including the floor price limitations, will apply for the term. A floor price is applied when prices for Canadian heavy oil are discounted relative to heavy oil prices at the U.S. Gulf Coast.

In 2013, Oil Sands royalties (excluding Syncrude) were approximately 7% (2012 – 6%) of Oil Sands operating revenues (excluding Syncrude). In 2013, Suncor incurred royalties on Syncrude operations averaging approximately 5% of Syncrude operating revenues before royalties (2012 – 6%).

Beginning on January 1, 2016, Suncor's Oil Sands Base and Syncrude operations will be subject to the generic royalty regime 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 within a range of 1% to 9% of R. Revenues used in royalty 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 2013, Suncor incurred minimum royalties at a rate of 7% of R for MacKay River (2012 – 6% of R) and royalties averaging 7% of R for Firebag (2012 – 6%), which continues in the pre-payout phase.

Exploration and Production

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

East Coast Canada – Assets and Operations

Based in St. John's, Newfoundland and Labrador, this business includes interests in three producing fields and future developments and extensions. Suncor is also involved in 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 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 mbbls/d (net 68 mbbls/d to Suncor) and oil storage capacity of 960 mbbls. Terra Nova was the first harsh environment development in North America to use a FPSO vessel. Actual annual production levels are lower than production capacity, reflecting current reservoir capability, including natural declines, gas and water injection and production limits, and asset and facility reliability. Production from Terra Nova began in January 2002. At December 31, 2013, there were 29 wells: 17 oil production wells, nine water injection wells and three gas injection wells. In 2013, Suncor's share of Terra Nova production averaged 14 mbbls/d compared to 9 mbbls/d in 2012. The company commenced off-station maintenance of the Terra Nova facility in late September 2013 for ten weeks to repair a mooring chain and perform preventive maintenance on the remaining eight chains. Production was reinstated in early December 2013. In comparison, the facility was off-line for approximately 27 weeks in 2012 as part of a dockside planned maintenance program.

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, in 2014, the company plans to perform maintenance on several production wells and to reinstate a second flowline to a subsea drill centre.

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., an ExxonMobil-managed company, the production system is a fixed GBS that sits on the ocean floor, and has gross production capacity of 230 mbbls/d (net 46 mbbls/d to Suncor) and oil storage capacity of 1,300 mbbls. Actual production levels are lower, reflecting current reservoir capability, including natural declines, gas and water injection and production limits, and asset and facility reliability. Hibernia commenced production in November 1997. At December 31, 2013, there were 62 wells in operation: 37 oil production wells, 14 single-zone water injection wells, six dual-zone water injection wells and five gas injection wells. In 2013, Suncor's share of Hibernia production averaged 27 mbbls/d (2012 – 26 mbbls/d). Hibernia uses the same transshipment terminal and similar system of shuttle tankers that are used for Terra Nova.

In 2010, final agreements were signed between the Hibernia co-venturers 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 from the GBS platform and are producing oil. The third production well has been drilled and will commence oil production in the first quarter of 2014. Current development plans include drilling up to two additional production wells from the GBS platform and six water injection wells in a subsea, excavated drill centre. Subsea infrastructure was installed in late 2013 and drilling of the first subsea water injection well began in early 2014. The number of production and injection wells required may be revised as the development proceeds and uncertainties regarding reservoir capability are resolved. Production from the HSEU is not expected to reach higher rates until 2015 when several planned water injection wells are completed.

White Rose and the White Rose Extensions

White Rose 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 mbbls/d (net 39 mbbls/d to Suncor) and oil storage capacity of 940 mbbls. Actual annual production levels are lower than production capacity, reflecting current reservoir capability, including natural declines, gas and water injection and production limits, and asset and facility reliability. Production from White Rose began in November 2005. At December 31, 2013, there were 33 wells in operation: 15 oil production wells, 15 water injection wells and three gas storage wells. In 2013, Suncor's share of White Rose production averaged 15 mbbls/d (2012 – 12 mbbls/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-venturers signed an agreement with the Province of Newfoundland and Labrador for the development of the White Rose Extensions, which include the South White Rose Extension, North Amethyst and West White Rose satellite fields. In May 2010, first oil was achieved in North Amethyst, and development drilling is ongoing. Development of the West White Rose field has been divided into two stages. The first stage was approved in 2010 and first oil was achieved in 2011.

In October 2013, the co-owners reached an agreement with the Government of Newfoundland and Labrador which resulted in amendments to the terms of the 2007 White Rose Expansion Project Framework Agreement, enabling the second stage development of West White Rose using a Wellhead Platform. Detailed engineering design for this project is currently underway and sanction is planned for the second half of 2014. Development of the South White Rose Extension began in 2013 with the installation of subsea gas injection infrastructure. Oil production and water injection infrastructure will be installed in 2014, and first oil for the South White Rose Extension is expected in late 2014 or early 2015.

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 mbbls of oil storage capacity and 52 well slots with a gross oil

production capacity of 150 mbbls/d (net 34 mbbls/d to Suncor). Detailed engineering and construction of the gravity-based structure and topsides fabrication progressed according to plan during 2013. First oil is expected in 2017. Suncor's share of the post-sanction project cost estimate provided by the project operator is approximately $2.8 billion.

Other Assets

The Ballicatters discovery, located 22 km northeast of Hibernia, was completed in 2011 and is comprised of gas and oil. The licence is operated by Suncor. In September 2013, the Canada-Newfoundland and Labrador Offshore Petroleum Board issued two Significant Discovery Licences (SDL 1051 and SDL 1052) for the Ballicatters discovery. Potential options to commercialize the discovery are currently being evaluated.

Suncor continues to pursue opportunities offshore Newfoundland and Labrador. The company holds interests in 50 other significant discovery licences and six other exploration licences offshore Newfoundland and Labrador.

International – Assets and Operations

Buzzard – North Sea

The Buzzard oilfield is located in the Outer Moray Firth, 95 km northeast of Aberdeen, Scotland. Operated by Nexen Petroleum U.K. Limited, a subsidiary of China National Offshore Oil Corporation Limited (CNOOC), the Buzzard facilities have gross installed production capacity of approximately 220 mbbls/d (net 66 mbbls/d to Suncor) of oil and 80 mmcf/d (net 24 mmcf/d to Suncor) of natural gas. Actual annual production levels are lower than production capacity, reflecting current reservoir capability, including natural declines, water injection limits, gas and water production limits, and asset and infrastructure reliability. 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, 2013, there were 45 wells: 33 oil and gas production wells and 12 water injection wells. In 2013, Suncor's share of Buzzard production averaged 56 mboe/d (2012 – 48 mboe/d).

In 2013, Buzzard completed three oil and gas development wells, which are intended to mitigate natural declines from the reservoir.

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

Golden Eagle – North Sea

During 2011, 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, Golden Eagle and Solitaire areas. The development plan incorporates a combined production, utilities and accommodation platform, linked to a separate wellhead platform, with an initial gross production capacity of 70 mboe/d (net 19 mboe/d to Suncor) from 21 development wells. In 2013, activities at Golden Eagle included the installation of two platform jackets and the wellhead topside, and the start of development drilling. The operator, Nexen Petroleum U.K. Ltd., estimates that the gross development cost will be £2 billion (Cdn$3.5 billion) and £0.6 billion (Cdn$1.0 billion) net to Suncor. 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 and appraisal initiatives in the North Sea include:

- Beta discovery (Norway) – Suncor is the operator for the PL375, PL375b and PL375c licences, in which it has a 70% interest. The company drilled the first exploration well in early 2010, encountering hydrocarbons. An appraisal well was drilled and tested later in 2010 with positive results. However, a third well drilled into a separate fault block did not encounter hydrocarbons. The company will continue to evaluate the Beta discovery by interpreting 3D seismic data acquired in 2013 and with further drilling starting in 2014. The Beta licences also contain other exploration opportunities.

- Butch discovery (Norway) – In 2011, Centrica plc, 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 was attempted but abandoned, due to well instability, before reaching its intended depth. In December 2013, the operator, began drilling the first of two additional wells on the licence to explore for oil in separate fault blocks from the discovery.

- Myrhauk prospect (Norway) – Suncor has a 20% interest in the PL539 licence, operated by Premier Oil plc. The operator has planned an exploration well for late 2014.

- Romeo discovery (U.K.) – During the second half of 2012 and into early 2013, the company was the

operator for an exploration well drilled in Block 30/11c, in which Suncor has a 57.857% interest. Drilling was completed early in 2013 and following evaluation, the well was determined to be non-commercial. No further work on this discovery has been planned.

- Scotney prospect (U.K.) – In 2013, Suncor, as operator, drilled a well in Block 20/05b to comply with a work commitment for the licence, in which it has a 32.86% interest. This well was completed in late April 2013 with no hydrocarbons encountered.

- Lily prospect (U.K.) – During the fourth quarter of 2013, the operator for the P928 20/1S licence, in which Suncor has a 29.89% interest, drilled an exploration well but did not encounter hydrocarbons.

- Blackjack prospect (U.K.) – During the second half of 2013, the operator of the P300 14/26a licence, in which Suncor has a 26.69% interest, conducted a site survey for a planned exploration well, which is scheduled to commence drilling during the first quarter of 2014.

Suncor continues to pursue other opportunities in the North Sea, the Norwegian Sea and the Barents Sea. The company holds interests in 30 exploration licences in the U.K. and Norwegian sectors of these areas.

Libya

In Libya, Suncor is signatory to seven EPSAs with the Libya National Oil Corporation (NOC). Five of the seven EPSAs contain producing fields and exploration prospects; the remaining two are exploration EPSAs that do not contain producing fields, one of which is being relinquished because the exploration program was not successful. Together, Suncor and the NOC jointly design and implement the development and redevelopment of existing fields in the Sirte Basin. Existing reserves are associated with five separate agreements which contain five primary producing 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 through a 12% share of a production cost recovery mechanism. Any petroleum remaining after cost recovery is referred to as excess petroleum, and is shared between Suncor and the NOC based on several factors. Suncor's share of the excess petroleum can range from 4% to 85%. The EPSAs expire on December 31, 2032, but include an initial five-year extension through the end of 2037. In 2013, Suncor's share of production in Libya averaged 21 mbbls/d, (2012 – 42 mbbls/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 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 in February 2011. In March 2011, Suncor declared force majeure under its EPSAs. Suncor exited development force majeure in December 2011 and exploration force majeure in June 2012, and production resumed to previous rates.

In July 2013, operations in Libya were again disrupted as political unrest resulted in the closure of seaport terminals. Production has been shut in since July 2013 and Suncor has not lifted production or recognized a sale since May 2013. Some seaports, largely on the country's western coast, were reopened in late December 2013, but eastern seaports, including the Ras Lanuf and Es Sider terminals through which Suncor's crude is exported, are still closed. As a result of this extended loss of production and uncertainty on timing of return to operations in Libya, Suncor recorded an after-tax impairment charge of $101 million against these assets in the fourth quarter of 2013.

Despite the seaport closures, Suncor continued exploration activities in 2013. During the year, two suspended wells and four additional exploration and appraisal wells were completed. Hydrocarbons were discovered in three of the wells, while the other three wells were assessed as dry holes.

During 2013, exploration force majeure extension agreements were signed by NOC and Suncor, relating to the 2011 force majeure situation, extending the exploration period from December 31, 2012 until April 12, 2014. In early 2014, an additional one-year extension to April 12, 2015, was approved by the NOC, with the formal extension agreements to follow later in 2014. The terms of the ESPAs allow for further extensions to be negotiated. The estimated cost of Suncor's remaining exploration work program commitment at December 31, 2013 is US$349 million.

At December 31, 2013, the company had an outstanding obligation of US$74 million for a signature bonus relating to Petro-Canada's ratification of the Libyan EPSAs in 2008.

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. Since 2011, 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 project comprised six natural gas 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 was delivered into the Syrian national gas grid for domestic electrical power generation. The Ebla project also included three crude oil wells.

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 and loss of value is determined not to be permanent.

Suncor impaired the remaining carrying value of its Syrian assets in the fourth quarter of 2013, resulting in an after-tax impairment charge of $422 million, as there has been no resolution of the political situation resulting in rising uncertainty with respect to the company's return to operations. Concurrently, the company recognized risk mitigation proceeds, received in 2012, of $300 million ($223 million after-tax) in net earnings. These were previously recorded as a long-term provision.

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. As a result, the company divested a number of non-core assets in this business area throughout 2010 and early 2011 and, in 2013, sold the majority of its remaining conventional natural gas business for $1 billion prior to closing adjustments and other closing costs. Following these disposals, the retained assets produce approximately 3 mboe/d of gas and 2 mbbl/d of liquids.

Natural gas extracted from the wellhead requires further processing. Suncor currently operates one natural gas processing plant at Wilson Creek (52.17% working interest ownership), with total licensed capacity of 34.6 mmcf/d, (18.1 mmcf/d net). Capacity not utilized by the company's own production is optimized through processing agreements with third-party producers.

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. Suncor holds firm capacity on the TransCanada PipeLines Gas Transmission Northwest Pipeline (GTN). The GTN firm capacity enables Suncor to deliver natural gas to the Pacific Northwest and California markets.

Crude oil production from North America Onshore assets is shipped on pipelines operated by independent pipeline companies. In most sales arrangements, Suncor is responsible for transportation to the point of sale.

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

Sales of Principal Products

Oil and gas production from East Coast Canada, the North Sea, and from North America Onshore is either marketed by our Energy Trading business, acting as a marketing agent or 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, prior to the shut in of production, crude oil was 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.

Exploration and Production Sales Summary:

Sales Volumes	2013 mboe/d	2013 % operating revenues	2012 mboe/d	2012 % operating revenues
East Coast Canada				
Crude oil	**55.9**	**40**	46.7	33
International				
Crude oil and NGLs	**75.2**	**53**	88.5	59
Natural gas	**1.2**	**0**	1.0	1
North America Onshore				
Crude oil and NGLs	**5.3**	**3**	5.6	3
Natural gas	**32.0**	**4**	48.3	4
Total Exploration and Production				
Crude oil and NGLs	**136.4**	**96**	140.8	95
Natural gas	**33.2**	**4**	49.3	5

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. 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 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 2013, Terra Nova royalties averaged 12% of gross revenue (2012 – 36%) and decreased primarily due to higher deductible costs in 2013.

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 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 tier three 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 subject to a 5% gross royalty. HSEU production will be subject to an additional tier three royalty that ranges between 2.5% and 7.5% of net revenue, depending on the price for WTI. The HSEU tier three royalty will coincide with the triggering of the tier one net royalty. During 2013, Hibernia (including the HSEU) royalties and NPI combined to average 36% of gross revenue (2012 – 35%).

The White Rose royalty for the base project consists of a sliding-scale basic royalty payable, with two tiers of incremental royalties, which became payable upon the achievement of specified levels of profitability. 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 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 an additional tier three royalty, equal to 6.5% of net revenue, which is payable if WTI is greater than Cdn$50/bbl. Currently, the White Rose Extensions are only subject to a 2.5% gross royalty. During 2013, total White Rose royalties averaged 16% of gross revenue (2012 – 12%).

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 primarily by the Natural Gas Royalty Regulation 2009, and by the Petroleum Royalty Regulation

2009. Royalties for natural gas and 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. Rates are dependent on well depth, production rates, price, and quality of the natural gas and crude oil. New wells receive an initial maximum rate of 5%, subject to volume and credit caps. In Alberta, costs for gathering, compressing, and processing the provincial government share of gas and NGLs are allowable deductions from gross royalties payable. Royalties for NGLs are determined based on the prescribed reference prices multiplied by flat rates of 30% for propane and butane, and 40% for pentanes.

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 formulas (rates) for natural gas production are different based on the date the well was drilled. Gas rates start as low as 9%, and are subject to a sliding scale with a maximum royalty rate of 27% as prices increase. B.C. provides royalty adjustments for deep drilling, lower production rates, and unique production methods. In B.C., field expenses (gathering, compression and processing) are allowed as cost of services deductions from gross royalties. Plant processing costs are included as adjustments to the provincial government valuation price. Royalties on NGLs are assessed at a flat rate of 20% of revenues.

During 2013, royalties for North America Onshore production averaged 10% of gross revenue (2012 – 7%).

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 mbbls/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 and to a lesser extent, by rail and marine transportation. With the commissioning of the rail offloading facility in the fourth quarter of 2013, the Montreal refinery has also started to receive inland crudes. Rail volumes are expected to increase to 35 mbbls/d by the end of the first quarter of 2014.

Production yield from the Montreal refinery includes gasoline, distillate, asphalt and petrochemicals, 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 mbbls/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 and has the ability to supplement supply with purchases from the U.S.

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 355,000 metric tonnes in 2013 (2012 – 362,000 metric tonnes). 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 2013, the plant produced approximately 804 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, 2014, Suncor increased the nameplate capacity of the Edmonton refinery to 142 mbbls/d from 140 mbbls/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. Crude oil is supplied to the refinery via company-owned and third-party pipelines.

Feedstock is supplied from Suncor's Oil Sands 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 41 mbbls/d of blended feedstock (comprised of 29 mbbls/d of bitumen and 12 mbbls/d of diluent) and process approximately 44 mbbls/d of sour SCO. The refinery can also process approximately 57 mbbls/d of sweet SCO through its synthetic train.

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 mbbls/d. The refinery processes primarily conventional crude oil, but also has the capability of processing up to 15 mbbls/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 58% 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, 2013 and 2012. 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	
	2013	2012	2013	2012	2013	2012	2013	2012
Oil Sands Base sweet synthetic	—	—	28.0	14.5	45.5	47.6	—	0.2
Oil Sands Base sour synthetic	—	—	11.3	22.7	59.3	49.9	8.0	8.3
Other synthetic	—	—	11.6	8.3	23.6	39.2	8.9	—
East Coast Canada light conventional (1)	14.6	21.6	—	—	—	—	—	—
Other light conventional	94.2	84.8	24.8	0.8	0.5	0.6	72.1	60.2
Sour conventional	0.2	4.7	—	22.2	—	—	11.3	—
Heavy conventional	16.7	18.0	—	—	—	0.6	—	27.0
Total	125.7	129.1	75.7	68.5	128.9	137.9	100.3	95.7
Utilization(2) (%)	92	94	89	81	92	102	102	98

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

(2) Refinery utilizations based on crude 2013 processing capacities (in mbbls/d): Montreal – 137; Sarnia – 85; Edmonton – 140; and Commerce City – 98.

Refined Petroleum Production Yield Mix (%)	Montreal		Sarnia		Edmonton		Commerce City	
	2013	2012	2013	2012	2013	2012	2013	2012
Gasoline	41	41	39	39	43	43	49	47
Distillates	37	35	46	46	52	52	35	34
Other	22	24	15	15	5	5	16	19

Distribution Terminals and Pipelines

Suncor owns and operates 13 major refined product 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 primarily under the Petro-Canada $_{TM}$ brand. As at December 31, 2013, this retail service station network consisted of 1,454 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 2013 (2012 – 4.8 million litres per site) and attracted an estimated 18% share (2012 – 17% share) of the national retail market.

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 a 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.

Retail Summary:

	As at December 31	
Locations	**2013**	2012
Retail Service Stations – Canada		
Petro-Canada$_{TM}$-branded	**1 454**	1 458
Sunoco$_{TM}$-branded	**7**	7
	1 461	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)	**259**	246

Sales Volumes	2013 thousands of m^3/d	2013 % operating revenues	2012 thousands of m^3/d	2012 % operating revenues
Gasoline (includes motor and aviation gasoline)				
Eastern North America	**18.4**		19.8	
Western North America	**20.9**		20.4	
	39.3	**46**	40.2	47
Distillates (includes diesel and heating oils, and aviation jet fuels)				
Eastern North America	**14.2**		12.0	
Western North America	**19.2**		19.0	
	33.4	**40**	31.0	39
Other (includes heavy fuel oil, asphalts, lubricants, petrochemicals, other)				
Eastern North America	**9.1**		9.8	
Western North America	**4.5**		4.6	
	13.6	**14**	14.4	14
	86.3		85.6	

Sales volumes for specific products are moderately 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 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, and the Sarnia and Montreal refineries. In addition, Suncor may purchase refined products from third-party suppliers.

Other Suncor Businesses

Energy Trading

Suncor's Energy Trading business is organized around five main commodity groups – crude oil, natural gas, sulphur, petroleum coke and electricity. Energy Trading provides commodity supply, transportation and pricing solutions. Our customers include mid-to large-sized commercial and industrial consumers, utility companies and energy producers.

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, such as pipeline disruptions or outages at refining customers. The Energy Trading business has entered into arrangements for other midstream infrastructure, such as pipeline, storage capacity and rail access, to optimize delivery of existing and future growth production, while generating trading earnings on select strategies and opportunities.

In the fourth quarter of 2013, following the completion of a rail offloading facility in Montreal, the Energy Trading business commenced rail shipments of non-proprietary crude to the Montreal refinery. This enabled the Montreal refinery to take advantage of the price differentials between inland and global crudes. A second rail offloading facility is planned for Tracy, Québec. It is envisioned that this will enable access to eastern tide waters for Oil Sands product and could commence as early as the second quarter of 2014.

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 has a production capacity of 400 million litres per year. In 2013, the plant produced 415.0 million litres of ethanol (2012 – 412.5 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 avoid carbon dioxide (CO_2) equivalent emissions of approximately 395,000 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. In December 2013, the Adelaide project received regulatory approval and construction is expected to commence in the second quarter of 2014. The Cedar Point project will continue to progress through the regulatory process in 2014. The two projects, based in Ontario, are expected to add 140 MW of gross installed capacity, increasing the gross installed capacity of Suncor's wind projects by 55%.

Suncor's operating wind power projects:

Wind Power Projects		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	2013	2012
Oil Sands	**6 310**	6 015
Exploration and Production	**479**	719
Refining and Marketing	**3 265**	3 175
Corporate, Energy Trading and Renewable Energy	**3 892**	4 023
Total	**13 946**	13 932

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 35% of the company's employees were covered by collective agreements at the end of 2013. Unifor, a new union created by the merger of the Communications, Energy and Paperworkers Union and the Canadian Auto Workers Union, represented the majority of these employees. Three-year collective agreements with approximately 4,250 employees in the company's Oil Sands, In Situ, refinery, lubricants and terminal operations were negotiated in 2013. The collective agreement with Unifor covering approximately 60 employees on Terra Nova expired September 30, 2013 and a renewal is currently being negotiated. A second collective agreement with the Teamsters Union, covering approximately 30 employees for the company's British Columbia terminals and warehouses, expired January 31, 2014 and a renewal is currently being negotiated. Collective agreements with the United Steel Workers representing approximately 250 employees at the Commerce City refinery and with the Sunoco Employees' Bargaining Association representing approximately 200 employees at the Sarnia refinery, will expire January 31, 2015 and February 28, 2015, respectively.

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 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 remains committed to reducing overall greenhouse gas (GHG) emissions intensity, in addition to other goals related to improving energy efficiency, reducing water use, increasing land reclamation and reducing air emissions. We 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, investing in technology research and development and pursuing other opportunities, both internally as well as through joint initiatives, such as our role in COSIA. 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 environmental performance, given legal, industry and community standards. Management systems are maintained by this committee to implement such policies and ensure compliance.

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 are 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. To support and highlight the goals of the EH&S policy, Suncor holds an Annual President's Operational Excellence Awards, which honour employees and contractors who demonstrate an exceptional commitment to health and safety. The awards ceremony highlights progress on safety initiatives and provides educational opportunities for all employees.

The aforementioned policies are reviewed annually and are available on the company's intranet and external website. Additional workshops and training sessions are also 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 Affairs 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.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The Statement of Reserves Data and Other Oil and Gas Information outlined below is dated February 28, 2014, with an effective date of December 31, 2013. The preparation date of the information is as of February 21, 2014.

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 data 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 and In Situ operations is based upon evaluations conducted by GLJ Petroleum Consultants Ltd. (GLJ) with an effective date of December 31, 2013, 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 assets offshore Newfoundland and Labrador (East Coast Canada), conventional assets offshore the U.K. (North Sea), conventional assets in Libya (Other International), and its natural gas and tight oil assets primarily located in Western Canada (North America Onshore), is based upon evaluations conducted by Sproule Associates Limited or Sproule International Limited (collectively, Sproule) with an effective date of December 31, 2013, 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, natural gas and NGL 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, general and administrative expense, and certain abandonment and reclamation costs. Future net revenues are presented on before-tax and after-tax bases.

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, natural gas and NGL reserves provided herein will be recovered. Actual SCO, bitumen, light and medium oil, natural gas and NGL 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 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 or 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 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, 2013
(forecast prices and costs)

	SCO[4] (mmbbls)		Bitumen (mmbbls)		Light & Medium Oil (mmbbls)		Natural Gas[5] (bcf)		NGLs (mmbbls)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Developed Producing												
Mining	1 863	1 670	—	—	—	—	—	—	—	—	1 863	1 670
In Situ	151	143	167	152	—	—	—	—	—	—	318	295
East Coast Canada	—	—	—	—	41	30	—	—	—	—	41	30
North America Onshore	—	—	—	—	2	1	42	35	1	1	10	8
Total Canada	2 014	1 812	167	152	43	32	42	35	1	1	2 232	2 003
North Sea	—	—	—	—	79	79	2	2	—	—	79	79
Other International	—	—	—	—	—	—	—	—	—	—	—	—
Total Proved Developed Producing	**2 014**	**1 812**	**167**	**152**	**121**	**110**	**45**	**38**	**1**	**1**	**2 311**	**2 082**
Proved Developed Non-Producing												
Mining	—	—	—	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—	—	—	—
North America Onshore	—	—	—	—	—	—	3	3	—	—	1	1
Total Canada	—	—	—	—	—	—	3	3	—	—	1	1
North Sea	—	—	—	—	4	4	—	—	—	—	4	4
Other International	—	—	—	—	149	54	—	—	—	—	149	54
Total Proved Developed Non-Producing	**—**	**—**	**—**	**—**	**152**	**58**	**4**	**4**	**—**	**—**	**153**	**58**
Proved Undeveloped												
Mining	—	—	845	764	—	—	—	—	—	—	845	764
In Situ	564	497	875	749	—	—	—	—	—	—	1 439	1 245
East Coast Canada	—	—	—	—	26	18	—	—	—	—	26	18
North America Onshore	—	—	—	—	2	1	4	4	—	—	2	2
Total Canada	564	497	1 720	1 512	27	20	4	4	—	—	2 312	2 029
North Sea	—	—	—	—	25	25	1	1	—	—	25	25
Other International	—	—	—	—	3	1	—	—	—	—	3	1
Total Proved Undeveloped	**564**	**497**	**1 720**	**1 512**	**55**	**45**	**5**	**5**	**—**	**—**	**2 340**	**2 055**
Proved												
Mining	1 863	1 670	845	764	—	—	—	—	—	—	2 707	2 433
In Situ	715	639	1 043	901	—	—	—	—	—	—	1 758	1 540
East Coast Canada	—	—	—	—	67	48	—	—	—	—	67	48
North America Onshore	—	—	—	—	3	3	50	42	1	1	13	11
Total Canada	2 578	2 309	1 887	1 665	70	51	50	42	1	1	4 544	4 033
North Sea	—	—	—	—	107	107	4	4	—	—	108	108
Other International	—	—	—	—	151	55	—	—	—	—	151	55
Total Proved	**2 578**	**2 309**	**1 887**	**1 665**	**329**	**213**	**54**	**46**	**1**	**1**	**4 804**	**4 195**
Probable												
Mining	520	459	397	339	—	—	—	—	—	—	916	798
In Situ	1 092	901	457	355	—	—	—	—	—	—	1 550	1 256
East Coast Canada	—	—	—	—	279	215	—	—	—	—	279	215
North America Onshore	—	—	—	—	2	2	36	31	1	1	9	7
Total Canada	1 612	1 360	854	694	281	217	36	31	1	1	2 754	2 277
North Sea	—	—	—	—	36	36	2	2	—	—	37	37
Other International	—	—	—	—	112	40	—	—	—	—	112	40
Total Probable	**1 612**	**1 360**	**854**	**694**	**429**	**293**	**39**	**33**	**1**	**1**	**2 902**	**2 354**
Proved Plus Probable												
Mining	2 382	2 129	1 241	1 103	—	—	—	—	—	—	3 624	3 232
In Situ	1 807	1 541	1 500	1 256	—	—	—	—	—	—	3 307	2 797
East Coast Canada	—	—	—	—	346	263	—	—	—	—	346	263
North America Onshore	—	—	—	—	5	4	86	73	2	2	21	18
Total Canada	4 189	3 669	2 741	2 359	351	268	86	73	2	2	7 298	6 310
North Sea	—	—	—	—	144	144	7	7	—	—	145	145

Other International	—	—	—	—	263	95	—	—	—	—	263	95
Total Proved Plus Probable	**4 189**	**3 669**	**2 741**	**2 359**	**758**	**506**	**92**	**80**	**2**	**2**	**7 706**	**6 549**

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

Summary of Oil and Gas Reserves [1][2][3]
as at December 31, 2013
(constant prices and costs)

	SCO[4] (mmbbls)		Bitumen (mmbbls)		Light & Medium Oil (mmbbls)		Natural Gas[5] (bcf)		NGLs (mmbbls)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Developed Producing												
Mining	1 863	1 660	—	—	—	—	—	—	—	—	1 863	1 660
In Situ	151	144	167	153	—	—	—	—	—	—	318	297
East Coast Canada	—	—	—	—	41	30	—	—	—	—	41	30
North America Onshore	—	—	—	—	2	1	36	32	1	1	8	7
Total Canada	2 014	1 804	167	153	43	31	36	32	1	1	2 231	1 995
North Sea	—	—	—	—	79	79	2	2	—	—	80	80
Other International	—	—	—	—	—	—	—	—	—	—	—	—
Total Proved Developed Producing	**2 014**	**1 804**	**167**	**153**	**122**	**111**	**39**	**34**	**1**	**1**	**2 311**	**2 075**
Proved Developed Non-Producing												
Mining	—	—	—	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—	—	—	—
North America Onshore	—	—	—	—	—	—	3	3	—	—	1	1
Total Canada	—	—	—	—	—	—	3	3	—	—	1	1
North Sea	—	—	—	—	4	4	—	—	—	—	4	4
Other International	—	—	—	—	150	55	—	—	—	—	150	55
Total Proved Developed Non-Producing	**—**	**—**	**—**	**—**	**154**	**59**	**4**	**4**	**—**	**—**	**155**	**60**
Proved Undeveloped												
Mining	—	—	845	790	—	—	—	—	—	—	845	790
In Situ	564	516	876	776	—	—	—	—	—	—	1 439	1 292
East Coast Canada	—	—	—	—	26	18	—	—	—	—	26	18
North America Onshore	—	—	—	—	2	2	5	4	—	—	3	3
Total Canada	564	516	1 720	1 566	28	20	5	4	—	—	2 312	2 102
North Sea	—	—	—	—	25	25	1	1	—	—	26	26
Other International	—	—	—	—	3	1	—	—	—	—	3	1
Total Proved Undeveloped	**564**	**516**	**1 720**	**1 566**	**56**	**46**	**6**	**6**	**—**	**—**	**2 340**	**2 129**
Proved												
Mining	1 863	1 660	845	790	—	—	—	—	—	—	2 707	2 450
In Situ	715	660	1 043	929	—	—	—	—	—	—	1 758	1 590
East Coast Canada	—	—	—	—	67	47	—	—	—	—	67	47
North America Onshore	—	—	—	—	4	3	44	39	1	1	12	11
Total Canada	2 577	2 321	1 888	1 719	70	51	44	39	1	1	4 544	4 098
North Sea	—	—	—	—	108	108	4	4	—	—	109	109
Other International	—	—	—	—	153	56	—	—	—	—	153	56
Total Proved	**2 577**	**2 321**	**1 888**	**1 719**	**332**	**215**	**48**	**44**	**1**	**1**	**4 806**	**4 263**
Probable												
Mining	520	462	397	344	—	—	—	—	—	—	916	806
In Situ	1 092	891	457	388	—	—	—	—	—	—	1 550	1 279
East Coast Canada	—	—	—	—	279	211	—	—	—	—	279	211
North America Onshore	—	—	—	—	2	2	32	30	1	1	8	8
Total Canada	1 612	1 353	854	732	281	213	32	30	1	1	2 753	2 303
North Sea	—	—	—	—	36	36	2	2	—	—	36	36
Other International	—	—	—	—	110	33	—	—	—	—	110	33
Total Probable	**1 612**	**1 353**	**854**	**732**	**427**	**282**	**34**	**33**	**1**	**1**	**2 900**	**2 372**
Proved Plus Probable												
Mining	2 382	2 122	1 241	1 133	—	—	—	—	—	—	3 624	3 255
In Situ	1 807	1 551	1 500	1 318	—	—	—	—	—	—	3 307	2 869
East Coast Canada	—	—	—	—	346	258	—	—	—	—	346	258
North America Onshore	—	—	—	—	6	5	76	70	2	1	20	18
Total Canada	4 189	3 673	2 742	2 451	352	264	76	70	2	1	7 297	6 401
North Sea	—	—	—	—	144	144	7	7	—	—	146	145
Other International	—	—	—	—	263	89	—	—	—	—	263	89
Total Proved Plus Probable	**4 189**	**3 673**	**2 742**	**2 451**	**759**	**497**	**83**	**76**	**2**	**1**	**7 705**	**6 635**

Please see Notes (1) through (5) 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, 2013
(forecast prices and costs)

	SCO[4]			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, 2012									
Mining	1 958	539	2 497	—	—	—	—	—	—
In Situ	665	1 060	1 725	964	695	1 659	—	—	—
East Coast Canada	—	—	—	—	—	—	76	268	344
North America Onshore	—	—	—	—	—	—	11	4	15
Total Canada	2 623	1 599	4 222	964	695	1 659	87	272	359
North Sea	—	—	—	—	—	—	124	43	167
Other International	—	—	—	—	—	—	151	117	268
Total	**2 623**	**1 599**	**4 222**	**964**	**695**	**1 659**	**362**	**432**	**794**
Extensions & Improved Recovery[6]									
Mining	—	—	—	845	397	1 241	—	—	—
In Situ	76	(66)	10	74	(69)	5	—	—	—
East Coast Canada	—	—	—	—	—	—	—	21	21
North America Onshore	—	—	—	—	—	—	2	1	3
Total Canada	76	(66)	10	919	327	1 246	2	22	24
North Sea	—	—	—	—	—	—	—	—	—
Other International	—	—	—	—	—	—	—	1	1
Total	**76**	**(66)**	**10**	**919**	**327**	**1 246**	**3**	**22**	**25**
Technical Revisions[7]									
Mining	(7)	(19)	(26)	—	—	—	—	—	—
In Situ	4	98	102	30	(168)	(139)	—	—	—
East Coast Canada	—	—	—	—	—	—	11	(10)	1
North America Onshore	—	—	—	—	—	—	1	—	—
Total Canada	(2)	79	76	30	(168)	(139)	12	(10)	1
North Sea	—	—	—	—	—	—	3	(7)	(3)
Other International	—	—	—	—	—	—	8	(6)	2
Total	**(2)**	**79**	**76**	**30**	**(168)**	**(139)**	**23**	**(23)**	**—**
Discoveries[8]									
Mining	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—
North America Onshore	—	—	—	—	—	—	—	—	—

Total Canada	—	—	—	—	—	—	—	—	—
North Sea	—	—	—	—	—	—	—	—	—
Other International	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

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

Reconciliation of Gross Oil Reserves [1][2][3] *(continued)*
as at December 31, 2013
(forecast prices and costs)

	SCO[4]			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	—	—	—	—	—	—	(10)	(2)	(12)
Total Canada	—	—	—	—	—	—	(10)	(2)	(12)
North Sea	—	—	—	—	—	—	—	—	—
Other International	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**(10)**	**(2)**	**(12)**
Economic Factors [9]									
Mining	—	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—	—
North America Onshore	—	—	—	—	—	—	—	—	—
Total Canada	—	—	—	—	—	—	—	—	—
North Sea	—	—	—	—	—	—	—	—	—
Other International	—	—	—	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Production									
Mining	(89)	—	(89)	—	—	—	—	—	—
In Situ	(30)	—	(30)	(25)	—	(25)	—	—	—
East Coast Canada	—	—	—	—	—	—	(21)	—	(21)
North America Onshore	—	—	—	—	—	—	(1)	—	(1)

Total Canada	(119)	—	(119)	(25)	—	(25)	(22)	—	(22)
North Sea	—	—	—	—	—	—	(20)	—	(20)
Other International	—	—	—	—	—	—	(8)	—	(8)
Total	**(119)**	**—**	**(119)**	**(25)**	**—**	**(25)**	**(49)**	**—**	**(49)**
December 31, 2013									
Mining	1 863	520	2 382	845	397	1 241	—	—	—
In Situ	715	1 092	1 807	1 043	457	1 500	—	—	—
East Coast Canada	—	—	—	—	—	—	67	279	346
North America Onshore	—	—	—	—	—	—	3	2	5
Total Canada	2 577	1 612	4 189	1 887	854	2 741	70	281	351
North Sea	—	—	—	—	—	—	107	36	144
Other International	—	—	—	—	—	—	151	112	263
Total	**2 577**	**1 612**	**4 189**	**1 887**	**854**	**2 741**	**329**	**429**	**758**

Please see Notes (1) through (9) 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]
as at December 31, 2013
(forecast prices and costs)

	Natural Gas[5]			NGLs		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	bcf	bcf	bcf	mmbbls	mmbbls	mmbbls
December 31, 2012						
Canada – North America Onshore	854	265	1 119	8	3	10
North Sea	5	4	9	—	—	—
Total	**859**	**268**	**1 128**	**8**	**3**	**11**
Extensions & Improved Recovery[6]						
Canada – North America Onshore	6	13	19	—	—	1
North Sea	—	—	—	—	—	—
Total	**6**	**13**	**19**	**—**	**—**	**1**
Technical Revisions[7]						
Canada – North America Onshore	6	(2)	4	—	—	—
North Sea	2	(1)	—	—	—	—
Total	**8**	**(3)**	**4**	**—**	**—**	**—**
Discoveries[8]						
Canada – North America Onshore	—	—	—	—	—	—
North Sea	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**
Acquisitions						
Canada – North America Onshore	—	—	—	—	—	—
North Sea	—	—	—	—	—	—
Total	**—**	**—**	**—**	**—**	**—**	**—**
Dispositions						
Canada – North America Onshore	(748)	(244)	(992)	(6)	(2)	(9)
North Sea	—	—	—	—	—	—
Total	**(748)**	**(244)**	**(992)**	**(6)**	**(2)**	**(9)**
Economic Factors[9]						
Canada – North America Onshore	—	4	5	—	—	—
North Sea	—	—	—	—	—	—
Total	**—**	**4**	**5**	**—**	**—**	**—**

Production						
Canada – North America Onshore	(69)	—	(69)	(1)	—	(1)
North Sea	(3)	—	(3)	—	—	—
Total	**(72)**	**—**	**(72)**	**(1)**	**—**	**(1)**
December 31, 2013						
Canada – North America Onshore	50	36	86	1	1	2
North Sea	4	2	7	—	—	—
Total	**54**	**39**	**92**	**1**	**1**	**2**

Please see Notes (1) through (9) 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, 2013

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

(2) Reserves data tables may not add due to rounding.

(3) Other International includes quantities of crude oil in Libya, which are expected to be produced under EPSAs. Under these EPSAs, net proved and probable reserves have been determined using the economic interest method. See the Definitions for Reserves Data Tables.

(4) SCO reserves figures include the company's diesel sales volumes.

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

(6) 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.

(7) Technical Revisions include changes in previous estimates resulting from new technical data or revised interpretations.

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

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

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 Canadian Oil and Gas Evaluation (COGE) Handbook. A summary of those definitions is set forth below.

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.

Proved and probable reserves categories 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, Suncor's share of profit revenue plus cost recovery revenue is divided by the associated oil or gas price forecast to determine Suncor's net volume entitlement, or **entitlement reserves**. The entitlement reserves are then adjusted to include reserves relating to income taxes payable by the national oil company on behalf of Suncor. 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 quantitative 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[1]

Net Present Value of Future Net Revenues Before Income Taxes
as at December 31, 2013
(forecast prices and costs)

	(in $ millions, discounted at % per year)					Unit Value
	0%	5%	10%	15%	20%	($/boe)
Proved Developed Producing						
Mining	42 653	27 208	19 172	14 594	11 765	11.48
In Situ	8 800	7 600	6 673	5 939	5 347	22.62
East Coast Canada	1 718	1 648	1 565	1 485	1 413	51.82
North America Onshore	179	152	131	115	103	16.59
Total Canada	53 350	36 609	27 541	22 133	18 628	13.75
North Sea	6 077	5 131	4 456	3 958	3 577	56.30
Other International	—	—	—	—	—	—
Total Proved Developed Producing	59 427	41 740	31 997	26 091	22 206	15.37
Proved Developed Non-Producing						
Mining	—	—	—	—	—	—
In Situ	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—
North America Onshore	11	8	6	5	4	9.72
Total Canada	11	8	6	5	4	9.72
North Sea	301	246	210	184	165	54.00
Other International	4 940	3 666	2 884	2 365	1 997	53.69
Total Proved Developed Non-Producing	5 252	3 920	3 101	2 554	2 166	53.23
Proved Undeveloped						
Mining	10 603	1 085	(1 751)	(2 709)	(3 036)	(2.29)
In Situ	30 387	13 972	7 064	3 814	2 127	5.67
East Coast Canada	1 127	920	781	681	606	43.30
North America Onshore	67	41	25	15	8	11.35
Total Canada	42 184	16 018	6 119	1 801	(295)	3.02
North Sea	1 596	1 272	1 023	829	675	40.78
Other International	69	44	28	17	10	30.93
Total Proved Undeveloped	43 849	17 334	7 170	2 647	390	3.49
Proved						
Mining	53 256	28 293	17 421	11 885	8 729	7.16
In Situ	39 187	21 572	13 736	9 753	7 474	8.92
East Coast Canada	2 845	2 569	2 346	2 167	2 019	48.63
North America Onshore	257	201	162	135	115	15.12
Total Canada	95 544	52 635	33 665	23 939	18 338	8.35
North Sea	7 974	6 650	5 689	4 971	4 417	52.62
Other International	5 009	3 710	2 912	2 382	2 007	53.31
Total Proved	108 528	62 994	42 267	31 292	24 762	10.07
Probable						
Mining	33 760	10 492	5 025	3 115	2 234	6.30
In Situ	64 266	16 632	6 407	3 463	2 314	5.10
East Coast Canada	15 373	9 020	5 829	4 013	2 885	27.11
North America Onshore	187	108	66	43	29	8.96
Total Canada	113 587	36 252	17 327	10 634	7 461	7.61
North Sea	3 441	2 424	1 811	1 416	1 146	49.14

Other International	4 593	2 500	1 520	1 009	717	37.70
Total Probable	121 620	41 176	20 658	13 059	9 324	8.78
Proved Plus Probable						
Mining	87 016	38 785	22 446	15 000	10 963	6.95
In Situ	103 452	38 204	20 143	13 216	9 788	7.20
East Coast Canada	18 218	11 588	8 175	6 180	4 904	31.05
North America Onshore	444	309	228	178	144	12.61
Total Canada	209 131	88 886	50 992	34 573	25 799	8.08
North Sea	11 415	9 073	7 500	6 387	5 563	51.73
Other International	9 602	6 210	4 433	3 391	2 724	46.68
Total Proved Plus Probable	230 148	104 170	62 925	44 351	34 086	9.61

Please see Notes (1) and (2) at the end of the Future Net Revenues tables for important information.

Net Present Value of Future Net Revenues After Income Taxes
as at December 31, 2013
(forecast prices and costs)

	(in $ millions, discounted at % per year)				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	32 682	20 624	14 426	10 932	8 791
In Situ	7 360	6 349	5 571	4 957	4 464
East Coast Canada	1 414	1 361	1 292	1 225	1 164
North America Onshore	179	152	131	115	103
Total Canada	41 635	28 487	21 420	17 229	14 521
North Sea	1 891	1 602	1 391	1 235	1 116
Other International	—	—	—	—	—
Total Proved Developed Producing	43 526	30 088	22 811	18 464	15 638
Proved Developed Non-Producing					
Mining	—	—	—	—	—
In Situ	—	—	—	—	—
East Coast Canada	—	—	—	—	—
North America Onshore	11	8	6	5	4
Total Canada	11	8	6	5	4
North Sea	114	96	84	75	68
Other International	1 753	1 324	1 059	882	756
Total Proved Developed Non-Producing	1 877	1 428	1 149	962	828
Proved Undeveloped					
Mining	8 725	886	(1 461)	(2 256)	(2 528)
In Situ	22 399	9 872	4 724	2 358	1 157
East Coast Canada	902	716	594	508	445
North America Onshore	67	41	25	15	8
Total Canada	32 093	11 515	3 882	625	(917)
North Sea	611	498	409	337	278
Other International	24	15	10	6	3
Total Proved Undeveloped	32 728	12 028	4 300	968	(636)
Proved					
Mining	41 407	21 510	12 965	8 676	6 263
In Situ	29 759	16 221	10 295	7 315	5 621
East Coast Canada	2 316	2 077	1 886	1 733	1 609
North America Onshore	257	201	162	135	115
Total Canada	73 739	40 009	25 308	17 859	13 608
North Sea	2 615	2 196	1 883	1 646	1 463
Other International	1 776	1 339	1 069	888	759
Total Proved	78 131	43 544	28 260	20 394	15 830
Probable					
Mining	25 171	7 700	3 631	2 228	1 589
In Situ	47 475	12 066	4 626	2 506	1 675
East Coast Canada	11 427	6 610	4 180	2 795	1 937
North America Onshore	187	108	66	43	29
Total Canada	84 260	26 484	12 503	7 572	5 229
North Sea	1 326	961	737	589	487
Other International	1 607	888	547	368	265

Total Probable	87 194	28 333	13 787	8 529	5 980
Proved Plus Probable					
Mining	66 578	29 210	16 596	10 904	7 852
In Situ	77 234	28 287	14 921	9 822	7 296
East Coast Canada	13 743	8 687	6 065	4 528	3 546
North America Onshore	444	309	228	178	144
Total Canada	158 000	66 493	37 810	25 431	18 837
North Sea	3 942	3 157	2 620	2 235	1 949
Other International	3 384	2 227	1 616	1 256	1 024
Total Proved Plus Probable	165 325	71 878	42 046	28 923	21 810

Total Future Net Revenues
as at December 31, 2013
(forecast prices and costs)

(in $ millions, undiscounted)	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Expenses	Future Net Revenues Before Deducting Future Income Tax Expenses	Future Income Tax Expenses	Future Net Revenues After Deducting Future Income Tax Expenses
Proved Developed Producing								
Mining	203 321	21 344	101 174	38 150	—	42 653	9 971	32 682
In Situ	25 287	1 704	11 741	2 852	190	8 800	1 440	7 360
East Coast Canada	4 550	1 227	1 077	157	371	1 718	303	1 414
North America Onshore	465	68	188	1	29	179	—	179
Total Canada	233 623	24 343	114 180	41 160	590	53 350	11 714	41 635
North Sea	8 823	—	2 373	223	149	6 077	4 187	1 891
Other International	—	—	—	—	—	—	—	—
Total Proved Developed Producing	242 446	24 343	116 553	41 383	739	59 427	15 901	43 526
Proved Developed Non-Producing								
Mining	—	—	—	—	—	—	—	—
In Situ	—	—	—	—	—	—	—	—
East Coast Canada	—	—	—	—	—	—	—	—
North America Onshore	24	1	9	3	1	10	—	10
Total Canada	24	1	9	3	1	10	—	10
North Sea	435	—	132	—	3	301	187	114
Other International	6 105	—	772	371	22	4 940	3 188	1 753
Total Proved Developed Non-Producing	6 565	1	913	374	26	5 252	3 374	1 877
Proved Undeveloped								
Mining	70 289	6 977	39 752	12 957	—	10 603	1 878	8 725
In Situ	134 949	18 567	53 411	31 817	766	30 387	7 988	22 399
East Coast Canada	2 835	831	527	317	33	1 127	225	902
North America Onshore	208	26	50	61	3	67	—	67
Total Canada	208 280	26 401	93 740	45 152	803	42 184	10 091	32 093
North Sea	2 720	—	518	561	45	1 596	985	611
Other International	102	—	7	25	0	69	45	24
Total Proved Undeveloped	211 102	26 401	94 265	45 738	849	43 849	11 121	32 728
Proved								
Mining	273 610	28 321	140 926	51 107	—	53 256	11 849	41 407
In Situ	160 236	20 271	65 152	34 669	956	39 187	9 428	29 759
East Coast Canada	7 385	2 058	1 604	474	405	2 845	528	2 316
North America Onshore	697	95	247	65	33	257	—	257
Total Canada	441 927	50 745	207 929	86 316	1 394	95 544	21 805	73 739
North Sea	11 978	—	3 023	784	197	7 974	5 359	2 615
Other International	6 207	—	779	395	23	5 009	3 233	1 776
Total Proved	460 113	50 745	211 732	87 495	1 613	108 528	30 397	78 131
Probable								
Mining	124 256	16 094	58 898	15 504	—	33 760	8 588	25 171
In Situ	227 832	40 307	79 246	43 319	694	64 266	16 791	47 475
East Coast Canada	30 811	7 108	4 214	3 916	201	15 373	3 947	11 427
North America Onshore	532	76	205	54	10	187	—	187
Total Canada	383 432	63 585	142 563	62 792	905	113 587	29 325	84 260

North Sea	4 205	—	676	65	24	3 441	2 115	1 326
Other International	4 945	—	281	68	3	4 593	2 985	1 607
Total Probable	392 583	63 585	143 520	62 925	932	121 620	34 425	87 194
Proved Plus Probable								
Mining	397 866	44 415	199 824	66 611	—	87 016	20 437	66 578
In Situ	388 068	60 578	144 399	77 988	1 650	103 452	26 218	77 234
East Coast Canada	38 196	9 165	5 818	4 390	606	18 218	4 475	13 743
North America Onshore	1 229	171	452	119	43	444	—	444
Total Canada	825 359	114 330	350 492	149 108	2 299	209 131	51 130	158 000
North Sea	16 184	—	3 699	849	221	11 415	7 473	3 942
Other International	11 152	—	1 061	464	25	9 602	6 219	3 384
Total Proved Plus Probable	852 695	114 330	355 252	150 420	2 545	230 148	64 822	165 325

Future Net Revenues by Production Group
as at December 31, 2013
(forecast prices and costs)

(before income taxes, discounted at 10% per year)	$ millions	$/boe[3]
Proved Developed Producing		
Unconventional – Mining	19 172	11.48
Unconventional – In Situ	6 673	22.62
Total Unconventional[4]	25 845	13.15
Light & Medium Oil[5]	6 083	54.96
Natural Gas[6]	69	10.50
Total Proved Developed Producing	31 997	15.37
Proved		
Unconventional – Mining	17 421	7.16
Unconventional – In Situ	13 736	8.92
Total Unconventional[4]	31 157	7.84
Light & Medium Oil[5]	11 036	51.62
Natural Gas[6]	74	9.27
Total Proved	42 267	10.07
Proved Plus Probable		
Unconventional – Mining	22 446	6.95
Unconventional – In Situ	20 143	7.20
Total Unconventional[4]	42 589	7.07
Light & Medium Oil[5]	20 230	39.86
Natural Gas[6]	106	7.73
Total Proved Plus Probable	62 925	9.61

(1) Figures may not add due to rounding.

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

(3) Per unit values are based on the company's net reserves.

(4) Total Unconventional includes SCO and bitumen.

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

(6) 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 reflect the flexibility of Suncor's operations which allows production from these properties to be either upgraded to SCO or sold as non-upgraded bitumen. The proportion of upgraded production is based on estimated available upgrading capacity and can vary depending on unplanned maintenance, fluctuations in production from mining and extraction operations, or changes in the company's overall Oil Sands development strategy, including with respect to planned upgrading capacity.

Future net revenues disclosed above include the estimated uplift to the future sales price and the associated upgrader operating and sustaining capital costs of upgrading approximately 35% of Firebag bitumen production to SCO, from 2014 to 2022, approximately 40% to 2033, and escalating thereafter. These factors translate to a $2.1 billion increase in future net revenues (total proved plus probable reserves, before tax, discounted at 10%) from In Situ production relative to the scenario where none of the bitumen is upgraded.

Revenues associated with excess power generated from our cogeneration facilities are included to the extent that all or a portion of a cogeneration unit is necessary for the operation of the In Situ property. All other revenue related to excess power generation is excluded from the evaluation for In Situ properties, as it does not represent revenues directly generated from oil and gas activities.

Prices Realized

For prices realized by Suncor during 2013, 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, 2014, as set out below. To the extent that there are fixed or presently determinable future prices or costs to which Suncor is legally bound by contractual or other obligations to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs have been incorporated into the forecast prices as applied to the pertinent properties. The forecast cost and price assumptions include increases in wellhead selling prices, take into account inflation with respect to future operating and capital costs, and assume the continuance of current laws and regulations. Price adjustments relating to factors such as product quality and transportation were applied on an individual property basis in cash flow calculations.

Forecast prices included a US$/Cdn$ exchange rate of 0.95, a Cdn$/€ exchange rate of 1.42 in 2014 and 1.40 thereafter, and a Cdn$/£ exchange rate of 1.67 in 2014 and 1.65 thereafter. Forecast costs included a 2% inflation factor, except for costs for Mining, which included 4% inflation for 2015 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 used 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 2013.

Constant prices included a US$/Cdn$ exchange rate of 0.97, a Cdn$/€ exchange rate of 1.36 and a Cdn$/£ exchange rate of 1.61.

Prices Impacting Reserves Tables[1]

Forecast	Brent North Sea[2]	WTI Cushing Oklahoma	WCS Hardisty Alberta[3]	Light Sweet Edmonton Alberta[4]	Pentanes Plus Edmonton Alberta[5]	AECO Gas[6]	B.C. Gas Westcoast Station 2[7]	National Balancing Point North Sea[8]
Year	US$/bbl	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/mmbtu	Cdn$/mmbtu
2014	107.50	97.50	75.60	92.76	105.20	4.03	3.88	11.32
2015	107.50	97.50	79.36	97.37	107.11	4.26	4.11	11.32
2016	105.00	97.50	81.50	100.00	107.00	4.50	4.35	11.05
2017	102.50	97.50	81.50	100.00	107.00	4.74	4.59	10.79
2018	102.50	97.50	81.50	100.00	107.00	4.97	4.82	10.79
2019	102.50	97.50	81.50	100.00	107.00	5.21	5.06	10.79
2020	102.50	98.54	82.13	100.77	107.82	5.33	5.18	10.79
2021	103.38	100.51	83.76	102.78	109.97	5.44	5.29	10.88
2022	105.45	102.52	85.44	104.83	112.17	5.55	5.40	11.10
2023	107.56	104.57	87.14	106.93	114.41	5.66	5.51	11.32
2024+	+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	109.05	96.90	73.66	91.50	103.39	3.10	3.06	10.74

(1) Each price from the GLJ forecast was adjusted for quality differentials and transportation costs applicable to the specific product and evaluation area.

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

(3) Price used when determining bitumen reserves presented as In Situ and Mining reserves, as well as for determining bitumen pricing for royalty calculation purposes.

(4) 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.

(5) Price used when determining the cost of diluent associated with bitumen reserves presented as In Situ and Mining reserves, as well as for determining bitumen pricing for royalty calculation purposes. A bitumen/diluent ratio of approximately two to three barrels of bitumen for one barrel of diluent was used. Price also used when determining certain NGL reserves.

(6) Price used when determining natural gas reserves 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.

(7) Price used when determining natural gas reserves in B.C. presented as North America Onshore reserves.

(8) 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 has 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 2013 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, 2013
(forecast prices and costs)

($ millions)	2014	2015	2016	2017	2018	Remainder	Total	Discounted At 10%
Proved								
Mining	3 141	3 785	3 641	2 780	1 927	35 833	51 107	23 816
In Situ	1 333	1 013	926	1 026	1 052	29 319	34 669	12 471
East Coast Canada	241	47	14	50	17	106	475	380
North America Onshore	18	14	22	11	—	—	65	54
Total Canada	4 733	4 859	4 603	3 867	2 996	65 258	86 316	36 721
North Sea	352	210	56	12	10	144	784	661
Other International	64	37	27	20	13	234	395	220
Total Proved	5 149	5 106	4 686	3 899	3 019	65 636	87 495	37 602
Proved Plus Probable								
Mining	3 220	3 869	3 729	2 895	2 046	50 852	66 611	26 119
In Situ	1 418	1 274	1 182	830	1 227	72 056	77 987	15 047
East Coast Canada	1 238	814	667	390	251	1 030	4 390	3 331
North America Onshore	50	18	32	19	—	—	119	102
Total Canada	5 926	5 975	5 610	4 134	3 524	123 938	149 107	44 599
North Sea	386	233	56	13	10	151	849	716
Other International	64	37	31	23	13	296	464	234
Total Proved Plus Probable	6 376	6 245	5 697	4 170	3 547	124 385	150 420	45 549

Development costs include costs associated with both developed and undeveloped reserves. Significant development activities and costs for 2014 are expected to include:

- For Mining, development of tailings management facilities and water management assets for Oil Sands Base and development of tailings management facilities and costs for mine train replacements at Syncrude. Remaining development costs for Oil Sands Base and Syncrude relate to capital investments that maintain the production capacity of existing facilities, including, but not limited to, major maintenance at Syncrude, routine maintenance, truck and shovel replacement, the replenishment of catalysts in hydrotreating units at the upgraders and improvements to utilities, roads and other facilities. Development activities for Fort Hills are expected to focus on detailed engineering, procurement, and ramp-up of field construction activities.

- For both Firebag and MacKay River operations within In Situ, the drilling of new well pairs and the design and construction of new well pads that are expected to maintain existing production levels in future years. Development activities for Firebag also include infill well drilling. Development activities at MacKay River are also expected to include a facility debottleneck, which is expected to increase production capacity by 20% to 38,000 bbls/d by the end of 2015.

- For East Coast Canada, construction and development drilling activities at Hebron, development drilling at Terra Nova, White Rose, Hibernia, and HSEU, installation of subsea infrastructure for the South White Rose Extension, and continuation of H_2S remediation activities at Terra Nova.

- For North Sea, at Buzzard, development drilling and facility upgrades, and at Golden Eagle, development drilling and the installation of subsea infrastructure.

- For North America Onshore, the development of the Wilson Creek field in the Cardium oil formation.

- For Other International, 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. This review considers the nature of Suncor's forecasted production and development plans, consistent with that assumed in our long-range planning, where determinable, for liabilities associated with its upstream operations as at December 31, 2013. Where no legal liability or constructive obligation for reclamation exists, potential costs have been excluded from the company's abandonment and reclamation cost estimates. Estimates are based on the anticipated method and extent of restoration, consistent with legal requirements, technological advances and the possible future use of the site.

At December 31, 2013, Suncor estimated its undiscounted, uninflated abandonment and reclamation costs, net of estimated salvage value, for surface leases, wells, facilities and pipelines pertaining to its upstream assets to be approximately $7.8 billion (discounted at 10%, approximately $2.1 billion). Suncor estimates that it will incur $1.1 billion of its identified abandonment and reclamation costs during the next three years (undiscounted: 2014 – $0.4 billion, 2015 – $0.4 billion, 2016 – $0.4 billion), over 77% 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 ($0.2 billion, 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 2,200 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 $7.8 billion total.

Abandonment and reclamation costs included in Suncor's $7.8 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 for which no reserves have been assigned.

Additional Information Relating to Reserves Data

Gross Proved and Probable Undeveloped Reserves

The tables below outline the gross proved and probable undeveloped reserves and represent undeveloped reserves additions, resulting from acquisitions, discoveries, infill drilling, improved recovery and/or extensions pertaining to the year in which the events first occurred.

Gross Proved Undeveloped Reserves
(forecast prices and costs)

	Prior		2011		2012		**2013**	
	First Attributed	Total at December 31 2010	First Attributed	Total at December 31 2011	First Attributed	Total at December 31 2012	**First Attributed**	**Total at December 31 2013**
SCO (mmbbls)								
Mining	—	—	—	—	—	—	**—**	**—**
In Situ	651	651	—	502	46	493	**75**	**564**
Total SCO	651	651	—	502	46	493	**75**	**564**
Bitumen (mmbbls)								
Mining	—	—	—	—	—	—	**845**	**845**
In Situ	360	360	315	661	64	785	**74**	**875**
Total Bitumen	360	360	315	661	64	785	**918**	**1 720**
Light & Medium Oil (mmbbls)								
East Coast Canada	28	28	1	27	4	32	**—**	**26**
North America Onshore [1]	—	—	—	—	—	—	**2**	**2**
Total Canada	28	28	1	27	4	32	**2**	**27**
North Sea	19	19	25	43	—	32	**—**	**25**
Other International[2]	6	6	2	6	4	4	**—**	**5**
Total Light & Medium Oil	53	53	28	76	7	67	**2**	**57**
Natural Gas (bcf)								
North America Onshore – Canada [1]	118	118	2	79	—	80	**4**	**4**
North Sea	1	1	2	3	—	2	**—**	**1**
Other International[2]	—	—	—	—	—	—	**—**	**—**
Total Natural Gas	119	119	4	81	—	82	**4**	**5**
NGLs (mmbbls)								
North America Onshore – Canada [1]	—	—	—	—	—	—	**—**	**—**
North Sea	—	—	—	—	—	—	**—**	**—**
Other International[2]	—	—	—	—	—	—	**—**	**—**
Total NGLs	—	—	—	—	—	—	**—**	**—**
Total (mmboe)	1 084	1 084	343	1 253	117	1 359	**996**	**2 342**

Gross Probable Undeveloped Reserves
(forecast prices and costs)

	Prior		2011		2012		2013	
	First Attributed	Total at December 31 2010	First Attributed	Total at December 31 2011	First Attributed	Total at December 31 2012	**First Attributed**	**Total at December 31 2013**
SCO (mmbbls)								
Mining	215	215	—	263	—	260	**—**	**265**
In Situ	400	400	916	1 212	—	1 043	**—**	**1 074**
Total SCO	615	615	916	1 475	—	1 303	**—**	**1 339**
Bitumen (mmbbls)								
Mining	37	37	—	—	—	—	**397**	**397**
In Situ	1 835	1 835	38	669	—	594	**—**	**369**
Total Bitumen	1 872	1 872	38	669	—	594	**397**	**766**
Light & Medium Oil (mmbbls)								
East Coast Canada	85	85	143	217	4	222	**21**	**235**
North America Onshore (1)	4	4	1	2	—	—	**1**	**1**
Total Canada	89	89	144	219	5	222	**22**	**236**
North Sea	15	15	14	17	2	33	**—**	**23**
Other International(2)	11	11	4	14	8	8	**—**	**9**
Total Light & Medium Oil	115	115	161	251	14	262	**22**	**267**
Natural Gas (bcf)								
North America Onshore – Canada (1)	136	136	3	87	1	49	**15**	**19**
North Sea	1	1	1	2	—	3	**—**	**2**
Other International(2)	240	240	221	347	—	—	**—**	**—**
Total Natural Gas	377	377	226	436	1	52	**15**	**21**
NGLs (mmbbls)								
North America Onshore – Canada (1)	1	1	—	1	—	1	**—**	**—**
North Sea	—	—	—	—	—	—	**—**	**—**
Other International(2)	8	8	6	11	—	—	**—**	**—**
Total NGLs	9	9	6	12	—	1	**—**	**—**
Total (mmboe)	2 673	2 673	1 159	2 480	14	2 170	**422**	**2 376**

(1) North America Onshore – Canada includes additional properties previously held by Suncor and subsequently disposed of in 2011 and 2013.

(2) Other International includes additional properties held by Suncor in Syria which were classified as contingent resources in 2012.

(3) Figures above may not add due to rounding.

Undeveloped In Situ reserves, which constitute approximately 61% of Suncor's gross proved undeveloped reserves and 61% of Suncor's gross probable undeveloped reserves, will take several years to develop. Undeveloped In Situ reserves have been assigned to reserves areas which are not classified as developed producing. Where supported by core hole wells, proved undeveloped reserves have been attributed to regions within 1.2 km from currently drilled or near-term planned production wells, where Alberta Energy Regulator (AER) approval is pending, and in the case of Firebag, also within 2.4 km from producing wells. 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. 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 constitute approximately 36% of Suncor's gross proved undeveloped reserves and 28% of Suncor's gross probable undeveloped reserves, and relate to the Fort Hills mining area and Syncrude Aurora South mining area, which have regulatory approvals substantially in place and are well-delineated by core hole drilling. First oil for the Fort Hills mining area is expected by the fourth quarter of 2017. The co-owners of Syncrude do not expect that the Aurora South mining area will come on-stream before 2024, when production from the Mildred Lake mining area is expected to be complete.

Undeveloped conventional (light and medium oil, natural gas and NGLs) reserves constitute approximately 3% of Suncor's gross proved undeveloped reserves and approximately 11% of Suncor's gross probable undeveloped reserves. Undeveloped conventional reserves primarily relate to the company's offshore assets at East Coast Canada, mainly associated with Hebron which is currently under development (first oil expected in 2017), and underdrilled or undrilled fault blocks related to extension areas in Hibernia, White Rose and Terra Nova. In developing these reserves, Suncor considers existing facility 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. 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.

Properties with no Attributed Reserves

The following table is a summary of properties to which no reserves are attributed as at December 31, 2013. 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	4 478 244	3 316 732
Libya	2 950 978	1 339 489
U.S. – Alaska	1 106 288	368 726
Norway	648 876	240 847
Syria[(1)]	345 194	345 194
U.K.	127 141	45 454
Australia (overriding royalty interest only)	113 027	—
Total	9 769 748	5 656 442

(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's undeveloped petroleum assets include 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. Certain Mining and In Situ properties may be in a mature phase of evaluation, where a significant amount of development has occurred; however, reserves cannot be attributed due to one or more contingencies, such as project sanction. 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 management process to review the economic viability of its properties, some properties are selected for further development activities, while others are temporarily deferred, sold, swapped or relinquished back to the mineral rights' owner.

In 2014, Suncor's rights to 135,696 net hectares in Canada, 3,565 net hectares in Alaska and 129,258 net hectares in Norway are scheduled to expire. Substantial portions of expiring lands may have their tenure continued beyond 2014 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 2014.

Oil and Gas Properties and Wells

The following table is a summary of oil and gas wells associated with the company's operations as at December 31, 2013.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing[1][2]		Producing		Non-Producing[1][2]	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta – In Situ[3]	213	213.0	58	58.0	—	—	—	—
Alberta – Conventional	50	32.5	3	2.7	55	26.6	7	4.6
British Columbia	—	—	—	—	38	33.2	6	4.9
Newfoundland	63	16.3	5	1.3	—	—	—	—
North Sea	33	9.9	2	0.6	—	—	—	—
Other International[4]	—	—	419	211.1	—	—	6	6.0
Total	359	271.7	487	273.7	93	59.8	19	15.5

(1) Non-producing wells include, but are not limited to, wells 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.

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

(3) SAGD well pairs are counted as one well. Wells where steam injection has commenced are classified as producing.

(4) Other International includes wells associated with the company's suspended operations in Syria. There are no reserves associated with wells in Syria, only contingent resources. The number assumes that no wells have been damaged since Suncor exited the country in December 2011.

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.

Proved plus probable developed non-producing reserves for North America Onshore, East Coast and North Sea are primarily associated with recently drilled development wells to be brought on production in 2014.

For Other International, non-producing reserves are associated with wells in Libya that are suspended due to political unrest in the country, which resulted in the closure of export terminal operations at eastern Libyan seaports. Production in Libya was shut in as at December 31, 2013, and as such, all associated reserves were classified as non-producing with the assumption that production would resume on April 1, 2014.

Costs Incurred

The table below summarizes the company's capital expenditures related to its oil and gas activities for the year ended December 31, 2013.

($ millions)	Exploration Costs	Proved Property Acquisition Costs	Unproved Property Acquisition Costs	Development Costs	Other Costs[1]	Total
Canada – Mining and In Situ	196	—	—	3 881	36	4 113
Canada – East Coast Canada and North America Onshore	14	—	2	979	—	995
Total Canada	210	—	2	4 860	36	5 108
North Sea	190	—	—	270	—	460
Other International	104	—	—	45	—	149
Total	504	—	2	5 175	36	5 717

(1) Other Costs 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, 2013.

	Exploratory Wells[1]		Development Wells	
Total number of wells completed	Gross	Net	Gross	Net
Canada – Oil Sands				
Oil	—	—	35	35.0
Service[2]	10	10.0	52	52.0
Stratigraphic Test[3]	187	74.0	539	292.6
Total	197	84.0	626	379.6
Canada – East Coast Canada and North America Onshore				
Oil	2	0.6	9	4.3
Natural Gas[4]	—	—	5	5.0
Dry Hole	—	—	2	0.4
Service[2]	—	—	3	0.7
Total	2	0.6	19	10.4
North Sea				
Oil	2	0.8	3	0.9
Dry Hole	1	0.3	1	0.3
Stratigraphic Test[3]	—	—	—	—
Total	3	1.1	4	1.2
Other International				
Oil	2	1.0	2	1.0
Dry Hole	3	1.5	—	—
Total	5	2.5	2	1.0

(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. Service wells for East Coast Canada include water injection wells.

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

(4) Natural Gas wells do not reflect four wells drilled in properties that were included as part of the sale of the majority of the company's conventional Natural Gas business, which was effective on January 1, 2013.

Significant exploration and development activities in 2013 included:

- For Mining, core hole drilling programs and other survey work at Oil Sands Base and Syncrude to provide additional information on areas the company expects to mine in the near term.
- For In Situ, 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, core hole drilling programs at MacKay River, Meadow Creek, Firebag and Lewis to further delineate resources, and activity to start up pilot technology projects.
- For East Coast Canada, exploration drilling for Terra Nova and White Rose Extensions, and development drilling for Hibernia, White Rose and the White Rose Extensions.
- For North Sea, exploration drilling for the Romeo, Scotney and Lily prospects, and development, including an appraisal well at Buzzard, all of which are in the U.K. sector of the North Sea.
- For Other International, exploration and oil development wells in Libya.
- For North America Onshore, development drilling of the Wilson Creek field in the Cardium oil formation and the Kobes/Altares area in the Montney shale gas formation.

Production History

The table below outlines the company's historical production information, by product type. Average price realized is net of transportation costs, but before royalties.

	Three months ended in 2013			
	Mar 31	Jun 30	Sept 30	Dec 31
Canada – Oil Sands[1]				
Total production (mbbls/d)	389.0	309.4	423.6	446.5
Total In Situ bitumen production (mbbls/d)	165.5	157.5	181.9	182.4
($/bbl)				
Average price realized	79.76	85.87	99.49	73.34
Royalties	(4.94)	(3.30)	(10.05)	(4.91)
Total cash operating costs	(35.36)	(46.09)	(33.76)	(37.09)
In Situ cash operating costs	(16.80)	(16.70)	(15.15)	(17.50)
Canada – Light & Medium Oil				
Total production (mbbls/d)	58.4	57.8	62.4	46.3
($/bbl)				
Average price realized	112.57	103.68	116.94	116.48
Royalties	(26.61)	(23.70)	(30.23)	(32.77)
Production costs	(9.05)	(11.44)	(9.46)	(15.90)
Netback	76.91	68.54	77.25	67.81
Canada – Natural Gas[2]				
Total production (mmcfe/d)	309	289	273	27
($/mcfe)				
Average price realized	4.66	5.30	4.28	6.92
Royalties	(0.58)	(0.49)	(0.37)	(0.52)
Production costs	(1.43)	(1.82)	(1.84)	(1.75)
Netback	2.65	2.99	2.07	4.65
North Sea – Light & Medium Oil[3]				
Total production (mboe/d)	55.3	57.8	50.4	59.8
($/boe)				
Average price realized	110.94	99.77	111.00	108.53
Royalties	—	—	—	—
Production costs	(5.80)	(6.29)	(7.64)	(4.94)
Netback	105.14	93.48	103.36	103.59

Other International – Light & Medium Oil

Total production (mboe/d)	41.9	27.0	13.1	1.0
($/boe)				
Average price realized	110.36	104.21	—	—
Royalties	(41.81)	(79.56)	—	—
Production costs	(3.34)	(3.47)	—	—
Netback	65.21	21.18	—	—

(1) Suncor measures cash operating cost on a production volumes basis for its Oil Sands Operations, which includes more expenses than production costs. For this reason, a netback calculation for SCO and bitumen is not presented in this table. 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 significant fields for the year ended December 31, 2013.

	SCO	Bitumen	Light & Medium Oil
	mbbls/d	mbbls/d	mbbls/d
Mining – Suncor	209.7	—	—
Mining – Syncrude	32.0	—	—
Firebag	70.1	53.0	—
MacKay River	2.8	24.9	—
Buzzard	—	—	55.8
Hibernia	—	—	27.1
White Rose	—	—	14.9
Terra Nova	—	—	14.2
Total	314.6	77.9	112.0

Production Estimates

The table below outlines the production estimates for 2014 that are included in the estimates of gross proved reserves and gross probable reserves as at December 31, 2013. Production estimates for 2014 for proved plus probable reserves, evaluated as at December 31, 2013: from Suncor's mining operations (excluding Syncrude) are 252.8 mbbls/d of SCO, approximately 40% of total estimated production for 2014; and from Firebag are 155.9 mbbls/d of SCO and bitumen, approximately 25% of total estimated production for 2014.

	SCO (mbbls/d)		Bitumen (mbbls/d)		Light & Medium Oil (mbbls/d)		Natural Gas (mmcf/d)		NGLs (mbbls/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada										
Proved	322.9	301.5	113.0	105.2	49.4	35.6	17.3	15.3	0.4	0.3
Probable	16.3	14.3	25.4	23.7	20.1	15.7	7.5	7.2	0.1	0.1
Proved Plus Probable	339.2	315.8	138.4	128.9	69.4	51.3	24.8	22.5	0.5	0.4
North Sea										
Proved	—	—	—	—	38.5	38.5	3.7	3.7	0.3	0.3
Probable	—	—	—	—	4.6	4.6	0.9	0.9	0.1	0.1
Proved Plus Probable	—	—	—	—	43.1	43.1	4.6	4.6	0.4	0.4
Other International										
Proved	—	—	—	—	30.9	5.8	—	—	—	—
Probable	—	—	—	—	—	—	—	—	—	—
Proved Plus Probable	—	—	—	—	30.9	5.8	—	—	—	—
Total										
Proved	322.9	301.5	113.0	105.2	118.7	79.9	21.0	19.0	0.7	0.6
Probable	16.3	14.3	25.4	23.7	24.7	20.3	8.4	8.1	0.2	0.2
Proved Plus Probable	339.2	315.8	138.4	128.9	143.4	100.2	29.4	27.1	0.9	0.8

Work Commitments

The practice of governments requiring companies to pledge to carry out work commitments in exchange for the right to carry out exploration for and development of hydrocarbons is common, particularly in unexplored or lightly explored regions of the world. The following table shows the estimated values of work commitments Suncor has made in regard to the lands it holds as at December 31, 2013. These commitments run through 2015 and are primarily for conducting seismic programs and drilling exploration wells.

Country/Area ($ millions)	2014	Total
Canada	18	24
North Sea	66	176
Other International	67	371

Forward Contracts and Transportation Obligations

Suncor may use financial derivatives to manage its exposure to fluctuations in commodity prices; however, Suncor did not consider any financial derivative transactions to be material in 2013. A description of Suncor's use of such instruments is provided in the 2013 audited Consolidated Financial Statements and related MD&A for the year ended December 31, 2013.

Tax Horizon

In 2013, Suncor was subject to cash tax in the majority of the local jurisdictions in which it generates earnings, including earnings related to its Canadian, North Sea and Other International production. Commencing in 2013, the company was cash taxable in Canada on the majority of its Canadian earnings.

Contingent Resources

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. The contingent resource estimates provided herein are best estimates of the quantities that are potentially recoverable. 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.

GLJ conducted independent assessments of Best Estimate contingent resources volumes for all of Suncor's Mining properties and its Firebag, Meadow Creek and Steepbank In Situ properties. For remaining In Situ properties, including MacKay River, GLJ audited assessments of Best Estimate contingent resources volumes (approximately 45% 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 contained in the Montney shale formation of northeast B.C., with an effective date of June 30, 2013. 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, 2013, except in the case of the contingent resources contained in the Montney shale formation of northeast B.C., which is as at June 30, 2013, 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 and international sanctions. As a result, volumes previously reported as reserves based on an evaluation conducted by Sproule with an effective date of December 31, 2011 were reclassified to contingent resources in 2012. As the situation in Syria has persisted throughout 2013, the company has not been able to update any information used by Sproule since the 2011 evaluation. The contingent resources estimate for Syria assumes that there has been no production subsequent to Sproule's 2011 evaluation and that infrastructure, including wells and pipelines, existing at December 31, 2011, exist at December 31, 2013. 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.

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.

Generally, 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.

	SCO	Bitumen	Light & Medium Oil	Natural Gas	NGLs	Total[5]
Best Estimate Contingent Resources	mmbbls	mmbbls	mmbbls	bcf	mmbbls	mmboe
Mining	4 610	813	—	—	—	5 423
In Situ	6 070	7 309	—	—	—	13 379
East Coast Canada	—	—	222	2 678	—	668
North America Onshore[1][2]	—	—	35	16 620	238	3 043
Total Canada[5]	10 680	8 122	256	19 298	238	22 514
North America Onshore – U.S.	—	—	—	449	—	75
North Sea[3]	—	—	52	103	—	69
Other International[4]	—	—	397	985	27	588
As at December 31, 2013[5]	10 680	8 122	705	20 836	265	23 245
As at December 31, 2012	11 001	8 109	759	20 205	250	23 486

(1) Includes offshore fields in the Arctic Islands.

(2) Includes contingent resources for the Montney shale formation of northeast B.C., with an effective date of June 30, 2013. The contingent resources associated with this formation include 8,075 bcf of Natural Gas and 214 mmbbls of NGLs.

(3) Includes offshore Norway and the U.K.

(4) Includes contingent resources for Syria of approximately 206 mmboe. A portion of these contingent resources 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.

(5) Figures may not add due to rounding.

Contingent resources decreased to 23,245 mmboe at December 31, 2013 from 23,486 mmboe at December 31, 2012, due primarily to the transfer of bitumen volumes related to the Fort Hills mining project to proved plus probable reserves in 2013 upon receipt of project sanction, partially offset by an increase in the company's In Situ contingent resources due to property acquisitions and additional drilling that added bitumen contingent resources primarily at the company's Lewis property.

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 23% of Suncor's total contingent resources, with 74% of these contingent resources related to 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

The economic status of Suncor's Mining contingent resources is currently undetermined and is dependent on the company's long-term resource development plan and its forecast for economic conditions. Prior to reserves being assigned, these contingent resources require the completion of further resource studies and delineation drilling, and the preparation of development plans and facility designs.

Non-Technical Contingencies

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 Joslyn North mining project has substantially all regulatory approvals in place. However, the project has recently applied for regulatory approval of an amended project development plan. 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.

Suncor's remaining Mining contingent resources are primarily contingent upon regulatory permits which must be obtained before project sanction decisions by Suncor's Board of Directors and/or co-owners, as applicable, are considered.

In Situ Contingent Resources

In Situ contingent resources comprise approximately 58% of Suncor's total contingent resources, with approximately 85% of these contingent resources related to 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. All In Situ contingent resources are associated with clastic or sandstone formations in the Fort McMurray oil sands area, and approximately 85% 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 reservoir performance versus performance estimated based on geological data. The geological data varies substantially as a result of the density of core holes used in the analyses. The density can be as low as one well per section, and as high as 16 wells per section.

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 data from numerous third-party pilots currently in operation in Grosmont carbonates. However, Suncor has not recognized any contingent resources in carbonate formations, as the viability of potential recovery processes in Suncor's carbonate interests has not yet 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 economic 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 and three-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 ten to 15 metres, depending on the horizon and property. Within the Athabasca oil sands region, economic production has been demonstrated at these thicknesses. 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 final investment decisions are subject to detailed assessments 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 associated with Suncor's Exploration and Production segment. These other contingent resources comprise approximately 19% 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 Wilson Creek area in Alberta, the Arctic Islands, the Mackenzie Delta and Corridor, and the Alaska Foothills.
- For East Coast Canada, 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, including the Northern Terrace area, and an extension from Buzzard.
- 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 Wilson Creek Cardium tight oil play have been determined to be economic. The economic viability of contingent resources in the Montney shale gas formation are undetermined and there are currently no near-term plans for development. The economic status of contingent resources associated with certain fields in the Arctic Islands is undetermined, but some 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 currently 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 developed fields are economic, while the economic viability of resources associated with fields that are not developed 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 reserves is 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 classified as reserves at December 31, 2011 are classified as contingent resources at December 31, 2013. 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 such as pipes and wells were damaged as a result of the political unrest, then the infrastructure will potentially need to be repaired or rebuilt in order to reclassify the resources as reserves.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, environmental, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government, and, with respect to export and taxation of oil and natural gas, by agreements among the governments of Canada and Alberta, among others, 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. All governments have the ability to change legislation. Suncor may engage in the discussion on proposed changes to ensure Suncor's interests are recognized. 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). 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 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. 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. Most of the current apportionments, however, are due to significant demand which far exceeds current pipeline capacity. 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 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 royalty rate 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 2013 was 10.64%.

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%.

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

Amounts presented in the 2013 audited Consolidated Financial Statements as royalties for production from our Libya operations are determined pursuant to EPSAs. 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 EPSAs. 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 receivable from the NOC.

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 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 and other companies 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 mine, 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 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 Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring, and the Lower Athabasca Regional Plan (LARP) that implements a land-use 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 enacted in the future. 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. 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, continuing land reclamation activities, installing new emissions abatement equipment, investing in research and development 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 including absolute GHG emissions limits, (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 with government 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 Conference of the Parties (UNFCCC COP) 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. The 2013 UNFCCC COP, held in Warsaw, Poland, continued to focus on creating a process and plan for all UN members to get to an agreement on 2020 commitments by the 2015 UNFCC COP to be held in Paris. Countries were asked to either pledge emissions reductions or contribute financially.

Canadian Federal GHG Regulations

The Government of Canada has already implemented regulation on two of Canada's largest sources of emissions, being transportation and thermal electricity generated from coal (which includes petroleum coke). 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 continues to address emissions of specific sectors of the economy and is engaged in negotiations with the Canadian oil and gas industry on proposed regulations for the sector while ensuring the industry remains globally competitive. It is expected that 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 is committed to fully complying with existing regulations and will continue to constructively 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* (SGER) enacted under the *Climate Change and Emissions Management Act (Alberta)*, facilities in Alberta, 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. With the divestiture of the Hanlan gas processing plant in 2013, four facilities now operated by Suncor in Alberta (Oil Sands Base plants, MacKay River operations, Firebag operations and the Edmonton refinery) are subject to, and continue to comply with, this legislation. For 2012, the total cost to comply with the SGER was approximately $20.5 million based on $15/tonne of CO_{2e}. Compliance under the SGER was achieved through reduced emissions per unit of production, and purchase and retirement of offset credits and payments to Alberta's Climate Change and Emissions Management Fund (Alberta Technology Fund). For 2014, the total compliance costs to Suncor are estimated to be between $20 million and $25 million, based on a cost of $15/tonne of CO_{2e}. The SGER is set to expire in September 2014. The Alberta government has indicated that the regulation will likely be renewed although any renewal may include changes such as increased intensity limits, decreased emissions thresholds and increased costs to the Alberta Technology Fund beyond the current $15/tonne of CO_{2e}.

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 by $5/tonne per year until 2012 when it reached its maximum of $30/tonne. This carbon tax is revenue 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 in prior years has exceeded the 25,000 tonne threshold that requires the reporting of emissions to be verified by third parties. As a result of Suncor's divestiture of various natural gas assets in 2013, the threshold for third-party verification is no longer met, but reporting of emission levels on its remaining properties remains a requirement. Similarly, 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.

Suncor's Montreal refinery is subject to Quebec's cap-and-trade system for GHG emissions because it produces more than 25,000 tonnes of CO_{2e} per year. Emitters must verify their emissions during specified compliance periods (the first period having commenced 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. As of January 1, 2014, Quebec's cap-and-trade system became formally linked to the WCI. 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 continues to consult with stakeholders on the development of a GHG reduction program for Ontario's industrial sector, intended to achieve equivalency with federal government regulation. Suncor's assets in Ontario include a refinery, a biofuel plant and a lubricants plant.

U.S. GHG Regulations

In an effort to build a green economy, the current administration 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. It is expected that the President's Administration will work to advance his 2013 Climate Action Plan to reduce GHG emissions. In the absence of other federal legislation on GHG emissions, the current administration of the United States is 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 remain unknown. In the meantime, the EPA has implemented a mandatory GHG reporting rule for all large facilities (emitting greater than 25,000 tonnes of CO_{2e} per year), which includes Suncor's Commerce City refinery.

The EPA has also mandated Renewable Fuel Standards 2, which encourages ethanol blending of 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 successfully appealed the ruling in 2013. The

State of California is now considering different compliance pathways for regulated parties.

International Regulations

Phase III (2008-2012) of the European Union Emissions Trading Scheme (EU ETS), which is applicable 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 regional 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), now the Alberta Energy Regulator or AER, 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} by providing space for the drying of tailings and ensuring adequate storage capacity for 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. Suncor is in compliance with the MFSP. Additional security may be 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.

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 the 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 AER 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 for some time, 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, and the possibility of seismic events.

Joint Controls /Alberta Implementation Plan for Oil Sands Monitoring

Canada and Alberta recently adopted the Joint Controls /Alberta Implementation Plan for Oil Sands Monitoring (Monitoring Plan). The intent of the Monitoring Plan is to provide a scientifically credible, integrated approach to environmental monitoring, including an improved understanding of the cumulative environmental impact of oil sands development. The total costs to the industry of enhanced monitoring under the Monitoring Plan have been estimated at approximately $50 million per year. The cost to Suncor under the Monitoring Plan are estimated at approximately $10 million per year.

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 worked closely with other companies in an effort to make tangible improvements to environmental, social and economic performance in the oil sands industry. These companies came together to pool financial resources and expertise. OSLI focused on land stewardship, water use, technology innovation and sustainable communities. OSLI has been superseded by the Canadian Oil Sands Innovation Alliance (COSIA). COSIA has 13 oil sands member companies and 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 mining 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. This initiative is now part of the COSIA. 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.

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. Some of these risks are common to operations in the oil and gas industry as a whole, while some are unique to Suncor. The company's enterprise risk committee (ERC), comprised of senior representatives from business and functional groups across Suncor, oversees entity-wide processes to identify, assess and report on the company's principal risks. A principal risk is an exposure that has the potential to materially impact the ability of one of our businesses or functions to meet or support a Suncor objective. The realization of any of the following risks, including Suncor's principle risk factors could have a material adverse effect on our business, financial condition, results of operations and cash flow:

Volatility of Commodity Prices

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 prices for all of these commodities can be influenced by global and regional supply and demand factors, which are factors that are beyond our control and can result in a high degree of price volatility.

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.

Refined petroleum products 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.

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. 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 writeoffs of the values of Suncor's assets or projects in development.

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 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, financial condition, results of operations and cash flow.

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.

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.

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.

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 startup – 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;
- The effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment; and
- Risk associated with offshore fabrication and logistics.

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.

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, and materially adversely affect Suncor's business, financial condition and results of operations, and may reduce cash flow available for growth or dividends and major project capital costs. This may 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.

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. Suncor positions itself to be ahead of proposed changes or engages in the discussion on proposed changes to ensure Suncor's interests are recognized.

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 the 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;
- Issues related to offset requirements for various land disturbances;
- 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 to $60/tonne of CO_{2e} 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 Suncor's 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 the volumes of fluid fine 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 includes management frameworks for air, land, and water quality that incorporate cumulative limits and triggers. As well, the LARP identifies areas related to conservation, tourism and recreation.

A management framework for water quantity (water withdrawals from the Athabasca River) has recently been announced. A management framework for biodiversity is under development.

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, by the operators 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. Water licences, like all regulatory approvals, contain conditions to be met in order to maintain compliance with the licence. Although 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, without evidence of an environmental impact associated with the licence and providing compliance is maintained, this is not likely to occur. 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, although there is currently no evidence that governments are contemplating such a fee at this time. In addition, the expansion of the company's projects may rely on securing licences for additional water withdrawal, and there can be no assurance that these licences will be granted or that they will be granted on terms favourable to Suncor.

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 certain derivative contracts. Following Suncor's response to a number of information requests in 2013, the CRA informed the company that it has not changed its original proposed position.

In the event that the CRA issues a formal Notice of Reassessment (NOR), Suncor plans to file a Notice of Objection to dispute this matter. However, notwithstanding the filing of an objection, 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.

Suncor strongly disagrees with the CRA's position and 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. If the company is unsuccessful in defending its tax filing position, it could be subject to an earnings impact of up to $1.2 billion.

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 also demand a large number of improvement initiatives that compete for resources, and may negatively impact the company should there be inadequate 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.

Market Access

Suncor anticipates higher production of bitumen in future years, due mainly to production growth from debottlenecking at both MacKay River and Firebag operations as well as MacKay River Stage 2. Due to its high 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 in recent years with 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.

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.

Third-Party Service Providers

Suncor is reliant on the operational integrity of a large number of third-party service providers, including input and output commodity transport (pipelines, rail, trucking, marine) and utilities associated with various Suncor facilities. Recent incidents around commodity transportation in North America have highlighted the nature of this risk generally; a disruption in service by one of these third parties can also have a dramatic impact on Suncor's operations. Pipeline constraints that affect takeaway capacity or supply of inputs could 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 Suncor's business, financial condition, results of operations and cash flow.

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 government royalties;
- Compliance with existing and emerging anti-corruption laws, including the *Foreign Corrupt Practices Act (United States)*, the *Corruption of Foreign Officials Act (Canada)* and the United Kingdom *Bribery Act*;
- Renegotiation of contracts with government entities and quasi-government agencies, including risks around ongoing negotiations in Libya with the NOC related to the periods 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 in 2012 and then completely impaired the assets in 2013. In 2013, the company also recorded an after-tax impairment charge of $101 million against its assets in Libya due to an extended loss of production, and uncertainty around return to operations arising from continued political unrest which began in mid-2013. There is no assurance as to if or when Suncor's operations in either Syria or Libya will resume or return to previous levels. Further, Suncor has not received signed agreements for the exploration period extension to April 12, 2015 under its Libyan EPSAs. Until these signed agreements are received, there remains a risk that Suncor's exploration period is not extended.

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.

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.

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, production constraints, reputational damage, operating and growth permit applications, censure, liability for cleanup costs and damages, and the loss of important licences and permits, which could also have a material adverse effect on Suncor's 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.

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 or maintain 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.

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.

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

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 cannot be assured. Advantages accrue to companies that can develop and adopt emerging technologies in advance of competitors. The inability to develop and monitor new technologies may impact the company's ability to develop its new or existing operations in a competitive or profitable manner.

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.

Exchange Rate Fluctuations

Our 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.

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 Unifor. 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.

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.

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.

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.

We believe that we have sufficient funds available to fund our planned capital expenditures for 2014. If cash flow from operations is lower than expected, if capital expenditures in 2014 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.

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.

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.

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.

Control Environment

Based on their evaluation as of December 31, 2013, our CEO and Interim 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, 2013, 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, 2013 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 controls over financial reporting and will make any modifications from time-to-time as deemed necessary.

As a result of current unrest in Syria, Suncor is not able to monitor the status of all of its assets in this country, including whether certain facilities have suffered damage. Suncor is continually assessing the control environment in Syria to the extent permitted by applicable law and does not consider the changes in that country 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

The 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 Board approved an increase in the quarterly dividend to $0.20 per share from $0.13 per share in the second quarter of 2013. In February 2014, the Board of Directors approved a per share increase of $0.03 to Suncor's quarterly dividend to $0.23 per common share. Dividends are paid subject to applicable law, if, as and when declared by the Board.

Year ended December 31	**2013**	2012	2011
Cash dividends per common share ($)	**0.73**	0.50	0.43

DESCRIPTION OF CAPITAL STRUCTURE

The company's authorized share capital is comprised of an unlimited number of common shares, an unlimited number of preferred shares issuable in series designated as senior preferred shares, and an unlimited number of preferred shares issuable in series designated as junior preferred shares.

As at December 31, 2013, there were 1,478,315,069 common shares issued and outstanding. To the knowledge of the Board of Directors and executive officers of Suncor, no person beneficially owns, or exercises control or direction over, securities carrying 10% or more of the voting rights attached to any class of voting securities of the company. The holders of common shares are entitled to attend all meetings of shareholders and vote at any such meeting on the basis of one vote for each common share held. As no senior preferred shares or junior preferred shares are issued and outstanding, common shareholders are entitled to receive any dividend declared by the Board 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 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. 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, 2013. 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 Program	US Commercial Paper Program
Standard & Poor's (S&P)	BBB+	Stable	A-1 (low)	A-2
Dominion Bond Rating Service (DBRS)	A (low)	Stable	R-1 (low)	R-1 (low)
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 to D, representing the range of such securities rated from highest to lowest quality. A Canadian rating by S&P of A-1 (low) is the third highest of eight categories and a US rating of A-2 is the second highest of six categories, 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.

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, 2013, are as follows:

TSX

	Price Range (Cdn$)		
	High	Low	Trading Volume (000s)
2013			
January	34.80	33.01	59 296
February	34.55	30.70	69 971
March	31.99	30.22	68 772
April	31.44	27.50	83 966
May	33.30	30.36	112 344
June	32.02	29.85	85 764
July	33.50	30.79	61 754
August	36.76	32.78	58 751
September	37.63	35.71	58 701
October	38.56	35.61	54 509
November	38.27	35.85	54 542
December	37.81	35.21	53 796

For information in respect of options to purchase common shares of Suncor and common shares issued upon the exercise of options, see the Share Capital note to the 2013 audited Consolidated Financial Statements, which is incorporated by reference into this AIF.

DIRECTORS AND EXECUTIVE OFFICERS

Directors

The following individuals are directors of Suncor on the date hereof. 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 consulting firm working in various countries with a focus on First Nations/corporate negotiations. Mr. Benson is also part owner of the private oil and gas company Tenax Energy Inc. and sits on the board of the Fort McKay Group of Companies, a community trust organization, as well as ECM Energy Services, Inc., based in Phoenix, Arizona. Mr. Benson retired from Exxon International and Imperial Oil Canada in 2000 after a long career as an operations manager and senior member of project management. While based in Houston, Texas, Mr. Benson worked on international projects based in Africa and the former Soviet Union. Mr. Benson recently became a member of the community advisory board for the Alberta Land Institute through the University of Alberta. Mr. Benson is a member of Beaver Lake Cree Nation, located in northeast Alberta.
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 (CIBC)[5]. 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 a 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, a member of the Advisory Council for Promoting Women on Boards, chancellor emeritus and chairman emeritus of the University of Alberta and chair of the advisory board of the Peter Lougheed Leadership Initiative. 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. (BP) 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 (USG)[6] and Air Products and Chemicals, Inc. He is also a member of the board of trustees of the University of Notre Dame.
John D. Gass Florida, USA	Director since 2014 Independent	John Gass is former vice president, Chevron Corporation, a major integrated oil and gas company, and former president, Chevron Gas and Midstream, positions he held from 2003 until his retirement in 2012. He has extensive international experience, having served in a diverse series of operational positions in the oil and gas industry with increasing responsibility throughout his career. Mr. Gass serves as a director of Southwestern Energy Co. and Weatherford International Ltd. He is also on the board of visitors for the Vanderbilt School of Engineering and is a member of the advisory board for the Vanderbilt Eye Institute. Mr. Gass graduated from Vanderbilt University in Nashville, Tennessee, with a bachelor's degree in civil engineering. He also holds a master's degree in civil engineering from Tulane University in New Orleans, Louisiana. A resident of Florida, he is a member of the American Society of Civil Engineers and the Society of Petroleum Engineers.
Paul Haseldonckx[2][3] Essen, Germany	Director since 2002 (Petro-Canada 2002 to July 31, 2009) Independent	Paul Haseldonckx was a member of the management board of Veba Oel AG (Veba), Germany's largest downstream oil and gas 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 has 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 a 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 past president and chief executive officer of SNC-Lavalin, a position he held from May 1996 until his retirement in May 2009. Mr. Lamarre is an Officer of the Order of Canada and a founding member and past chair of the Commonwealth Business Council. He is also past chair of the board of directors of the Conference Board of Canada and a founding member of the World Economic Forum's Governors for Engineering & Construction. Currently, he serves as a director of PPP Canada Inc. and is 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. Among others, he has previously served on the board of the Royal Bank of Canada.
Maureen McCaw[1][2] Alberta, Canada	Director since 2004 (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, Ms. McCaw is a director of the Canadian Broadcasting Corporation, and the Edmonton International Airport, and a member of the Alberta Securities Commission. Ms. McCaw also serves on a number of Alberta boards and advisory committees, including the Nature Conservancy of Canada (Alberta) and the Epcor Community Essentials Council 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 the 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 2004 (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, as well as being the chairman for its Audit Committee and Risk Review 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 20 years of experience in the Canadian diamond business, including her previous roles as vice president of Aber Resources, now Dominion Diamond Corp., and as founder and CEO of Stornoway Diamond Corp. Currently, Ms. Thomas is chief executive officer and a director of Kaminak Gold Corporation, and a director of Lucara Diamond Corp. and Dundee Precious Metals Inc. (Dundee)[7]. 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 one of twelve founding CEOs in Canada's Oil Sands Innovation Alliance, 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.
Michael M. Wilson Alberta, Canada	Director since 2014 Independent	Michael Wilson is former president and chief executive officer of Agrium Inc., a retail supplier of agricultural products and services and a wholesale producer and marketer of agricultural nutrients, which is headquartered in Calgary, a position he held from 2003 until his retirement in 2013. He previously served as executive vice president and chief operating officer. Mr. Wilson has significant experience in the petrochemical industry, serving as president of Methanex Corporation, and holding various positions with increasing responsibility in North America and Asia with Dow Chemical Company. Mr. Wilson has a bachelor's degree in chemical engineering from the University of Waterloo and currently serves on the boards of Agrium Inc. (Agrium)[8], Celestica Inc. and Finning International Inc. He is also the chair of the Calgary Prostate Cancer Foundation.

(1) Human Resources and Compensation Committee

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

(3) Audit Committee

(4) Governance Committee

(5) Mr. D'Alessandro has indicated that he will not stand for re-election as a director of CIBC at CIBC's next annual meeting.

(6) Mr. Ford has indicated that he will not stand for re-election as a director of USG at USG's next annual meeting.

(7) Ms. Thomas has indicated that she will not stand for re-election as a director of Dundee at Dundee's next annual meeting scheduled for May 7, 2014.

(8) Mr. Wilson has indicated that he will not stand for re-election as a director of Agrium at Agrium's next annual meeting.

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
Stephen D.L. Reynish	Alberta, Canada	Executive Vice President, Strategy & Corporate Development and Interim Chief Financial Officer
Eric Axford	Alberta, Canada	Executive Vice President, Business Services
Mark Little	Alberta, Canada	Executive Vice President, Upstream
Mike MacSween	Alberta, Canada	Executive Vice President, Major Projects
Kris Smith	Ontario, Canada	Executive Vice President, Refining and Marketing
Paul Gardner	Alberta, Canada	Senior Vice President, Human Resources
Janice Odegaard	Alberta, Canada	Senior Vice President, General Counsel and Corporate Secretary

As at February 24, 2014, the directors and executive officers of Suncor as a group beneficially owned, or controlled or directed, directly or indirectly, common shares of Suncor representing 0.05% of outstanding common shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

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 securities legislation that was in effect for a period of more than 30 consecutive days while the director or executive 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.

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; or

(b) has, within the last ten years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

No director or executive officer of Suncor has been subject to:

(a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

(b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE INFORMATION

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

Composition of the Audit Committee

The Audit Committee is comprised of Mr. O'Brien (Chairman), Mr. D'Alessandro, Mr. 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 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 provisions;

(c) experience preparing, auditing, 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) 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 paid or payable to PricewaterhouseCoopers LLP, the company's auditors are as follows:

($ thousands)	**2013**	2012
Audit Fees	**6 108**	5 904
Audit-Related Fees	**519**	429
Tax Fees	**50**	50
All Other fees	**60**	125
Total	**6 737**	6 508

Audit Fees were paid, or are payable, 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 in respect of which we are or were a party to, or in respect of which any of our property is or was the subject during the year ended December 31, 2013, nor are there any such 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 the year ended December 31, 2013, (b) any other 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 year ended December 31, 2013.

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, 2013, 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, which 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, direct or indirect, 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 company's independent auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have issued an independent auditor's report dated February 24, 2014 in respect of the Corporation's Consolidated Financial Statements, which comprise the Consolidated Balance Sheets as at December 31, 2013 and December 31, 2012 and the Consolidated Statements of Comprehensive Income, Changes in Shareholders' Equity and Cash Flows for the years ended December 31, 2013 and December 31, 2012, and the related notes, and the Corporation's internal control over financial reporting as at December 31, 2013. PricewaterhouseCoopers LLP has advised that they are independent with respect to the company 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 2014 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, and is not required to adopt, the director independence standards contained in Section 303A.02 of the NYSE's Listed Company Manual, including with respect to its audit committee and compensation committee. The Board has not adopted, nor is it required to adopt, procedures to implement Section 303A.05(c)(iv) of the NYSE's Listed Company Manual in respect of compensation committee advisor independence. 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 2013 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 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:

- *The continuation of the debottlenecking project of existing central processing facilities at MacKay River in 2014 that will increase bitumen processing capacity by 20% by the end of 2015 to a total capacity of 38 mbbls/d; and*
- *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.*

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

- *The next scheduled turnaround at Oil Sands Operations is in 2016; and*
- *At Terra Nova, the company plans to perform maintenance on several production wells and to reinstate a second flowline to a subsea drill centre in 2014.*

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

- *The company's expectations that the Voyageur South and Audet leases can be developed using mining techniques;*
- *The company's expectations that the Meadow Creek, Lewis, Chard and Kirby leases can be developed using in situ techniques and that the company may undertake exploratory drilling programs;*
- *That the company plans to drill 50 core holes at Lewis and 66 core holes at Meadow Creek in winter 2014;*
- *The company plans to work towards a 2014 sanction decision of an additional central processing facility at MacKay River, which is targeted to have an initial design capacity of approximately 20 mbbls/d and first oil in 2017;*
- *Plans for centrifuge technology at Syncrude that separates water from tailings;*
- *The Fort Hills mining project is expected to produce first oil by the fourth quarter 2017 and is expected to achieve 90% of its planned production capacity of 180 mbbls/d (73 mbbls/d net to Suncor) within its first year;*
- *The company's expected share of costs for the Fort Hills project are $5.5 billion and project activities for 2014 are expected to focus on detailed engineering, procurement and ramp-up of field construction activities;*
- *Plans for the Joslyn North mining project, including 157 mbbls/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;*
- *Development plans for the HSEU, which include drilling up to two additional production wells from the GBS platform and six water injection wells and that production from the HSEU is not expected to reach higher rates until 2015 when the planned water injection wells are completed;*
- *That the number of production and injection wells required at HSEU may need to be revised as development proceeds and uncertainties about reservoir capability are resolved;*
- *Development plans for the White Rose Extensions, including that the sanction is planned for the second half of 2014, that water injection infrastructure will be*

installed in 2014 and first oil for the South White Rose Extension is expected in late 2014 or early 2015;

- *Plans for Hebron that include a concrete GBS, integrated topsides deck, 1,200 mbbls of oil storage capacity, 52 well slots and a gross oil production capacity of 150 mbbls/d (net 34 mbbls/d to Suncor);*
- *Suncor's share of the post-sanction project costs for the Hebron project will be approximately $2.8 billion and first oil is expected in 2017;*
- *That three oil and gas development wells drilled at Buzzard in 2013 will mitigate natural declines from the reservoir;*
- *Development plans for Golden Eagle, which include an initial gross production capacity of 70 mboe/d (19 mboe/d net to Suncor) from 21 development wells, gross development costs of £2 billion (Cdn$3.5 billion), (£0.6 billion (Cdn$1.0 billion) net to Suncor), and the company's expectations that first production will occur late in 2014 or early 2015;*
- *Plans for the continued evaluation of and further appraisal drilling in 2014 for the Beta discovery;*
- *Plans to commence drilling on an exploration well at the Myrhauk prospect late in 2014 and the Blackjack prospect during the first quarter of 2014;*
- *That Suncor's estimated cost remaining on its Libya exploration work program committed at December 31, 2013 was US$349 million;*
- *Suncor's expectation that rail transport to Montreal will increase to approximately 35 mbbls/d by the end of 2014;*
- *The company expects to commission a second rail offloading facility in Tracy, Québec which is expected to enable access to eastern tide-waters for Oil Sands product and could commence as early as the second quarter of 2014; and*
- *The company's expectation that construction of the Adelaide wind project will commence in the second quarter of 2014, that the Cedar Point project will continue to progress through the regulatory process in 2014, and that the two projects will add 140 MW of gross installed capacity, increasing the gross installed capacity of Suncor's wind projects by 55%.*

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 ten years, and that Syncrude expects to make regulatory applications for these areas in 2014;*
- *The co-owners of Syncrude do not expect that the Aurora South mining area will come on-stream before 2024, when production from the Mildred Lake mining area is expected to be complete;*
- *Suncor's plans to continue to pursue other opportunities in the North Sea, the Norwegian Sea and the Barents Sea;*
- *Suncor's plans to continue to pursue opportunities in offshore Newfoundland and Labrador;*
- *The compliance costs to Suncor in relation to SGER for 2014 are expected to be between $20 million and $25 million;*
- *Significant development activities and costs anticipated to occur or be incurred in 2014;*
- *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;*
- *Suncor's plans around its reserves and 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 2014;*
- *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; and*
- *Suncor's belief that it will be able to successfully defend its original filing position in relation to certain derivative contracts so that ultimately no increased income tax payable will result from CRA's position.*

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; 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, such as Suncor's current disagreement with the Canada Revenue Agency relating to the settlement of certain derivative contracts, including the risk that Suncor may not be able to successfully defend its original filing position if it is reassessed and ultimately be required to pay increased taxes as a result; 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; outages to third party infrastructure that could cause disruptions to production; 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:

- Monitoring the effectiveness and integrity of the Corporation's financial reporting systems, management information systems and internal control systems, and by monitoring financial reports and other financial matters.
- Selecting, monitoring and reviewing the independence and effectiveness of, and where appropriate replacing, subject to shareholder approval as required by law, external auditors, and ensuring that external auditors are ultimately accountable to the Board of Directors and to the shareholders of the Corporation.
- Reviewing the effectiveness of the internal auditors, excluding the Operations Integrity Audit department, which is specifically within the mandate of the Environment, Health & Safety Committee (references throughout this mandate to "Internal Audit" shall not include the Operations Integrity Audit department); and
- Approving on behalf of the Board of Directors certain financial matters as delegated by the Board, including the matters outlined in this mandate.

The Committee does not have decision-making authority, except in the very limited circumstances described herein or where and to the extent that such authority is expressly delegated by the Board of Directors. The Committee conveys its findings and recommendations to the Board of Directors for consideration and, where required, decision by the Board of Directors.

Constitution

The Terms of Reference of Suncor's Board of Directors set out requirements for the composition of Board Committees and the qualifications for committee membership, and specify that the Chair and membership of the committees are determined annually by the Board. As required by Suncor's by-laws, unless otherwise determined by resolution of the Board of Directors, a majority of the members of a committee constitute a quorum for meetings of committees, and, in all other respects, each committee determines its own rules of procedure.

Functions and Responsibilities

The Audit Committee has the following functions and responsibilities:

Internal Controls

1. Inquire as to the adequacy of the Corporation's system of internal controls, and review the evaluation of internal controls by Internal Auditors, and the evaluation of financial and internal controls by external auditors.
2. Review management's monitoring of compliance with the Corporation's Standards of Business Conduct Code.
3. Establish procedures for the confidential submission by employees of complaints relating to any concerns with accounting, internal control, auditing or Standards of Business Conduct Code matters, and periodically review a summary of complaints and their related resolution.
4. Review the findings of any significant examination by regulatory agencies concerning the Corporation's financial matters.
5. Periodically review management's governance processes for information technology resources, to assess their effectiveness in addressing the integrity, the protection and the security of the Corporation's electronic information systems and records.
6. Review the management practices overseeing officers' expenses and perquisites.

External and Internal Auditors

7. Evaluate the performance of the external auditors and initiate and approve the engagement or termination of the external auditors, subject to shareholder approval as required by applicable law.
8. Review the audit scope and approach of the external auditors, and approve their terms of engagement and fees.
9. Review any relationships or services that may impact the objectivity and independence of the external auditor, including annual review of the auditor's written statement of all relationships between the auditor (including its affiliates) and the Corporation; review and approve all engagements for non-audit services to be provided by external auditors or their affiliates.
10. Review the external auditor's quality control procedures including any material issues raised by the most recent quality control review or peer review and any issues raised by a government authority or professional authority investigation of the external auditor, providing details on actions taken by the firm to address such issues.

11. Review and approve the appointment or termination of the Head of Internal Audit, annually review a summary of the remuneration of the Head of Internal Audit, and periodically review the performance and effectiveness of the Internal Audit function including compliance with The Institute of Internal Auditors' International Professional Practices Framework for Internal Auditing.

12. Review the Internal Audit Department Charter, and the plans, activities, organizational structure and qualifications of the Internal Auditors, and monitor the department's independence.

13. Provide an open avenue of communication between management, the Internal Auditors or the external auditors, and the Board of Directors.

Financial Reporting and other Public Disclosure

14. Review the external auditor's management comment letter and management's responses thereto, and inquire as to any disagreements between management and external auditors or restrictions imposed by management on external auditors. Review any unadjusted differences brought to the attention of management by the external auditor and the resolution thereof.

15. Review with management and the external auditors the financial materials and other disclosure documents referred to in paragraph 16, including any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgements of management that may be material to financial reporting, including alternative treatments and their impacts.

16. Review and approve the Corporation's interim consolidated financial statements and accompanying management's discussion and analysis ("MD&A"). Review and make recommendations to the Board of Directors on approval of the Corporation's annual audited financial statements and MD&A, Annual Information Form and Form 40-F. Review other material annual and quarterly disclosure documents or regulatory filings containing or accompanying audited or unaudited financial information.

17. Authorize any changes to the categories of documents and information requiring audit committee review or approval prior to external disclosure, as set out in the Corporation's policy on external communication and disclosure of material information.

18. Review any change in the Corporation's accounting policies.

19. Review with legal counsel any legal matters having a significant impact on the financial reports.

Oil and Gas Reserves

20. Review with reasonable frequency Suncor's procedures for:

    (A) the disclosure, in accordance with applicable law, of information with respect to Suncor's oil and gas activities, including procedures for complying with applicable disclosure requirements;

    (B) providing information to the qualified reserves evaluators (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; 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. Conduct periodic review of and provide oversight on the specific Suncor Principal Risks which have been delegated to the Committee for oversight.

Pension Plan

24. Review the assets, financial performance, funding status, investment strategy and actuarial reports of the Corporation's pension plan including the terms of engagement of the plan's actuary and fund manager.

Security

25. Review on a summary basis any significant physical security management, IT security or business recovery risks and strategies to address such risks.

Other Matters

26. Conduct any independent investigations into any matters which come under its scope of responsibilities.

27. Review any recommended appointees to the office of Chief Financial Officer.

28. Review and/or approve other financial matters delegated specifically to it by the Board of Directors.

Reporting to the Board

29. Report to the Board of Directors on the activities of the Audit Committee with respect to the foregoing matters as required at each Board meeting and at any other time deemed appropriate by the Committee or upon request of the Board of Directors.

Approved by resolution of the Board of Directors on November 19, 2013

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, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2013, 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, 2013, 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 22, 2014	Canada	—	20 143	—	20 143
GLJ Petroleum Consultants Ltd.	Oil Sands Mining January 8, 2014	Canada	—	22 446	—	22 446
			—	**42 589**	**—**	**42 589**

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, February 28, 2014

"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, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2013, 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, 2013, 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 21, 2014	Newfoundland Offshore, Canada	—	8 175	—	8 175
Sproule Associates Limited	North America Onshore February 21, 2014	Western Canada	—	228	—	228
Sproule International Limited	North Sea February 21, 2014	North Sea, United Kingdom	—	7 500	—	7 500
Sproule International Limited	Other International February 21, 2014	Libya	—	4 433	—	4 433
			—	**20 336**	**—**	**20 336**

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, February 28, 2014

"Harry J. Helwerda"

Harry J. Helwerda, P.Eng., FEC, FGC (Hon.)
President & Chief Operating Officer and Director

SCHEDULE "E" – FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Suncor Energy Inc. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2013, 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

"*Stephen D.L. Reynish*"
STEPHEN D.L. REYNISH
Interim 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

February 28, 2014

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 72 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 85 and 86 of Annual Information Form.

CODE OF ETHICS

See pages 29 and 30 of Annual Information Form.

FEES PAID TO PRINCIPAL ACCOUNTANT

See page 86 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 59 of Exhibit 99-2.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

See page 59 of Exhibit 99-2.

IDENTIFICATION OF THE AUDIT COMMITTEE

See page 85 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: February 28, 2014

PER: /s/ STEVEN D.L. REYNISH

Steven D.L. Reynish
Interim 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, 2013
99-2	Management's Discussion and Analysis for the fiscal year ended December 31, 2013, dated February 28, 2014
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 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

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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
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APPROVAL OF NON-AUDIT SERVICES
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IDENTIFICATION OF THE AUDIT COMMITTEE
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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, 2013

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 Canadian generally accepted accounting principles applicable to publically accountable enterprises, which is within the framework of International Financial Reporting Standards as issued by the International Accounting Standards Board incorporated into the CICA Handbook Part 1. 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 reserve 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 resource 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

Stephen D.L. Reynish
Interim Chief Financial Officer

February 28, 2014

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 (1992) 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, 2013, 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, 2013. 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, 2013 has been audited by PricewaterhouseCoopers LLP, independent auditor, as stated in their report which appears herein.





Steve W. Williams
President and Chief Executive Officer

Stephen D.L. Reynish
Interim Chief Financial Officer

February 28, 2014

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of
Suncor Energy Inc.

We have completed integrated audits of Suncor Energy Inc.'s 2013 and 2012 consolidated financial statements and its internal control over financial reporting as at December 31, 2013. 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., which comprise the consolidated balance sheets as at December 31, 2013, December 31, 2012 and January 1, 2012 and the consolidated statements of comprehensive income, changes in shareholders' equity and cash flows for each of the two years in the period ended December 31, 2013, 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 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 the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards also 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 Suncor Energy Inc. as at December 31, 2013, December 31, 2012 and January 1, 2012 and its financial performance and its cash flows for each of the two years in the period ended December 31, 2013 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 Suncor Energy Inc.'s internal control over financial reporting as at December 31, 2013, based on criteria established in Internal Control – Integrated Framework (1992), 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

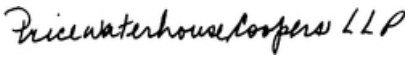
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal 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, Suncor Energy Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2013, based on criteria established in Internal Control – Integrated Framework (1992) issued by COSO.



Chartered Accountants
Calgary, Alberta

February 28, 2014

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 ($ millions)	2013	2012 (restated – note 6)
Revenues and Other Income		
Operating revenues, net of royalties (note 7)	**39 593**	38 107
Other income (note 8)	**704**	419
	40 297	38 526
Expenses		
Purchases of crude oil and products	**17 293**	17 047
Operating, selling and general (notes 9 and 26)	**9 447**	8 897
Transportation	**845**	685
Depreciation, depletion, amortization and impairment (notes 10 and 17)	**4 892**	6 446
Exploration	**322**	309
Gain on disposal of assets (note 34)	**(137)**	(44)
Project start-up costs	**15**	60
Voyageur upgrader project charges (note 33)	**82**	—
Financing expenses (note 11)	**1 162**	142
	33 921	33 542
Earnings before Income Taxes	**6 376**	4 984
Income Taxes (note 12)		
Current	**2 083**	1 515
Deferred	**382**	729
	2 465	2 244
Net Earnings	**3 911**	2 740
Other Comprehensive Income (Loss)		
Items That May be Subsequently Reclassified to Profit or Loss:		
Foreign currency translation adjustment	**325**	(16)
Cash flow hedges reclassified to net earnings	**—**	(1)
Items That Will Not be Reclassified to Profit or Loss:		
Actuarial gain (loss) on employee retirement benefit plans, net of income taxes	**579**	(134)
Other Comprehensive Income (Loss)	**904**	(151)
Total Comprehensive Income	**4 815**	2 589
Per Common Share (dollars) (notes 6 and 13)		

Net earnings – basic	**2.61**	1.77
Net earnings – diluted	**2.60**	1.76
Cash dividends	**0.73**	0.50

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

CONSOLIDATED BALANCE SHEETS

($ millions)	**December 31 2013**	December 31 2012	January 1 2012
		(restated – note 6)	(restated – note 6)
Assets			
Current assets			
Cash and cash equivalents (note 14)	**5 202**	4 385	3 781
Accounts receivable	**5 254**	5 201	5 383
Inventories (note 16)	**3 944**	3 697	4 169
Income taxes receivable	**294**	799	704
Total current assets	**14 694**	14 082	14 037
Property, plant and equipment, net (notes 17, 33 and 34)	**57 270**	55 434	52 563
Exploration and evaluation (note 18)	**2 772**	3 284	4 554
Other assets (note 19)	**422**	419	413
Goodwill and other intangible assets (note 20)	**3 092**	3 104	3 114
Deferred income taxes (note 12)	**65**	78	60
Total assets	**78 315**	76 401	74 741
Liabilities and Shareholders' Equity			
Current liabilities			
Short-term debt (note 21)	**798**	775	761
Current portion of long-term debt (note 21)	**457**	311	12
Accounts payable and accrued liabilities	**7 090**	6 446	7 742
Current portion of provisions (note 24)	**998**	856	811
Income taxes payable	**1 263**	1 165	964
Total current liabilities	**10 606**	9 553	10 290
Long-term debt (note 21)	**10 203**	9 938	10 004
Other long-term liabilities (note 22)	**1 464**	2 319	2 402
Provisions (note 24)	**4 078**	4 932	3 751
Deferred income taxes (note 12)	**10 784**	10 444	9 702
Shareholders' equity	**41 180**	39 215	38 592
Total liabilities and shareholders' equity	**78 315**	76 401	74 741

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 28, 2014

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($ millions)	2013	2012 (restated – note 6)
Operating Activities		
Net earnings	**3 911**	2 740
Adjustments for:		
Depreciation, depletion, amortization and impairment	**4 892**	6 446
Deferred income taxes	**382**	729
Accretion	**192**	182
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**605**	(181)
Change in fair value of derivative contracts	**95**	10
Gain on disposal of assets	**(137)**	(44)
Share-based compensation	**214**	214
Exploration	**82**	145
Settlement of decommissioning and restoration liabilities	**(423)**	(433)
Recognition of risk mitigation proceeds	**(300)**	—
Other	**(101)**	(75)
Decrease (increase) in non-cash working capital (note 15)	**688**	(874)
Cash flow provided by operating activities	**10 100**	8 859
Investing Activities		
Capital and exploration expenditures	**(6 777)**	(6 957)
Acquisitions (note 33)	**(515)**	—
Proceeds from disposal of assets	**943**	67
Proceeds from risk mitigation instruments	**—**	300
Divestiture of pipeline contract (note 24)	**(76)**	—
Other investments	**(18)**	(3)
Increase in non-cash working capital (note 15)	**(90)**	(51)
Cash flow used in investing activities	**(6 533)**	(6 644)
Financing Activities		
Net change in short-term debt	**(32)**	13
Net change in long-term debt	**170**	414
Repayment of long-term debt	**(312)**	—
Issuance of common shares under share option plans	**112**	188
Purchase of common shares for cancellation, net of option premiums (note 25)	**(1 675)**	(1 451)
Dividends paid on common shares	**(1 095)**	(756)

Cash flow used in financing activities	**(2 832)**	(1 592)
Increase in Cash and Cash Equivalents	**735**	623
Effect of foreign exchange on cash and cash equivalents	**82**	(19)
Cash and cash equivalents at beginning of year	**4 385**	3 781
Cash and Cash Equivalents at End of Year	**5 202**	4 385
Supplementary Cash Flow Information		
Interest paid	**711**	642
Income taxes paid	**1 339**	1 510

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 (restated – note 6)	Number of Common Shares (thousands)
At January 1, 2012	20 303	545	(207)	14	17 937	38 592	1 558 636
Net earnings	—	—	—	—	2 740	2 740	—
Foreign currency translation adjustment	—	—	(16)	—	—	(16)	—
Net changes in cash flow hedges	—	—	—	(1)	—	(1)	—
Actuarial loss on employee retirement benefit plans, net of income taxes of $49	—	—	—	—	(134)	(134)	—
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	(609)	—	—	—	(842)	(1 451)	(46 862)
Liability for share purchase commitment	(19)	—	—	—	(29)	(48)	—
Share-based compensation	—	83	—	—	—	83	—
Dividends paid on common shares	—	—	—	—	(756)	(756)	—
At December 31, 2012	19 945	579	(223)	13	18 901	39 215	1 523 057
Net earnings	**—**	**—**	**—**	**—**	**3 911**	**3 911**	**—**
Foreign currency translation adjustment	**—**	**—**	**325**	**—**	**—**	**325**	**—**
Actuarial gain on employee retirement benefit plans, net of income taxes of $201	**—**	**—**	**—**	**—**	**579**	**579**	**—**
Total comprehensive income	**—**	**—**	**325**	**—**	**4 490**	**4 815**	**—**
Issued under share option plans	**159**	**(32)**	**—**	**—**	**—**	**127**	**4 750**
Issued under dividend reinvestment plan	**28**	**—**	**—**	**—**	**(28)**	**—**	**—**
Purchase of common shares for cancellation (note 25)	**(648)**	**—**	**—**	**—**	**(1 027)**	**(1 675)**	**(49 492)**
Change in liability for share purchase commitment (note 25)	**(89)**	**—**	**—**	**—**	**(169)**	**(258)**	**—**
Share-based compensation	**—**	**51**	**—**	**—**	**—**	**51**	**—**

Dividends paid on common shares	—	—	—	—	(1 095)	(1 095)	—
At December 31, 2013	**19 395**	**598**	**102**	**13**	**21 072**	**41 180**	**1 478 315**

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

NOTES TO 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 joint arrangement 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 28, 2014, the date the Board of Directors approved the consolidated financial 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 consolidated 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 joint operations. Joint ventures are investments in entities over which the company has significant influence and are accounted for using the equity method. All intercompany balances and transactions are eliminated.

(b) Foreign Currency Translation

Functional currencies of the company's individual entities are 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 entities 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, respectively. 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. 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 trading operations are carried at fair value less costs of disposal, 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 delineation 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 Exploration expense.

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 development infrastructure, such as wellhead equipment, well platforms, well pairs, 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, processing and power generation facilities, utility plants, and all renewable energy, refining, and marketing assets, are capitalized as plant and equipment within Property, Plant and Equipment.

Stripping activity required to access oil sands mining resources incurred in the initial development phase is capitalized as part of 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 (or part of a 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. Once transferred to oil and gas properties within 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 exploration and evaluation costs associated with oil sand mines which are depreciated on a straight-line basis over the life of the mine and property acquisition costs which are depleted over proved reserves.

Capital expenditures are not depleted until assets are substantially complete and ready for their intended use.

Costs to develop oil and gas properties other than oil sands properties, including costs of dedicated infrastructure, such as well pads and wellhead equipment, 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. Costs to develop and construct oil sands mines are depreciated on a straight-line basis over the life of the mine.

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

Natural gas processing plants	15 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 reviewed quarterly to assess whether there is any indication of impairment. Goodwill and intangible assets that have an indefinite useful life are tested for impairment annually. Exploration and Evaluation assets are also tested for impairment immediately prior to being transferred to Property, Plant and Equipment.

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 of disposal and value-in-use. In determining fair value less costs of disposal, 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 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, if there has been a change in the estimates and judgments used to determine the asset's recoverable amount. If such indication exists, the carrying amount of the CGU or asset is increased to its revised recoverable amount which cannot exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, had no impairment been recognized.

Impairments and impairment reversals are recognized within Depreciation, Depletion, Amortization and Impairment.

Financial Assets

At each reporting date, the company assesses whether there is evidence that financial assets that are carried at amortized cost are impaired. If a financial asset carried at amortized cost is impaired, the impairment 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 of disposal. 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 are 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 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 are 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.

The company recognizes the financial statement impact of a tax filing position when it is probable, based on the technical merits, that the position will be sustained upon audit. The company assesses possible outcomes and their associated probabilities. If the company determines payment is probable, it measures the tax position at the best estimate of the amount of tax payable.

(n) Pensions and Other Post-Retirement Benefits

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

The cost of pension benefits earned by employees in the defined contribution pension plan are expensed as incurred. The cost of defined benefit pension plans and other post-retirement benefits are actuarially determined using the projected unit credit method based on present pay levels and management's best estimates of demographic and financial assumptions. Pension benefits earned during the current year are recorded in Operating, Selling and General expense. Interest costs on the net unfunded obligation are recorded in Financing Expenses. 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.

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.

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.

(p) Financial Instruments

The company classifies its financial instruments into one of the following categories: fair value through profit or loss; assets available for sale; held-to-maturity investments; loan and receivables and financial liabilities measured at amortized cost. 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. The company classifies derivative financial instruments as fair value through profit and loss, cash and cash equivalents and accounts receivable as loans and receivables, financial instruments included in other assets as available for sale, and 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, 2013 by independent qualified reserves evaluators. 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, 2013, 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 of disposal 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 evaluates tax positions, annually or when circumstances require, which involves judgment and could be subject to differing interpretations of applicable tax legislation. The company recognizes a tax provision when a payment to tax authorities is considered probable. However, the results of audits and reassessments and changes in the interpretations of standards may result in changes to those positions and potentially 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 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, timing of reversals, 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.

Joint Arrangements

The classification of joint arrangements structured through separate vehicles as either joint ventures or joint operations requires significant judgment and depends on the legal form and contractual terms of the arrangement as well as other facts and circumstances. These include whether there is exclusive dependence on the parties to the joint arrangement for cash flows through the sale of product and funding of operations, and to assess the rights of the economic benefits of the assets and obligation for funding the liabilities of the arrangements.

A joint arrangement whereby the parties take their share of substantially all of the output of the joint arrangement would be an indicator for classification as a joint operation, regardless of structure of the arrangement, and accounted for by recognizing the company's share of assets and liabilities jointly owned and incurred, and the recognition of its share of revenue and expenses of the joint operation.

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

The standards and interpretations that are issued but not yet effective up to the date of issuance of the company's financial statements, and that may have an impact on the disclosures and financial position of the company, are disclosed below. The company intends to adopt these standards and interpretations, if applicable, when they become effective.

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IAS 32 *Financial Instruments: Presentation* to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event. Retrospective application of amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014, with earlier application permitted. The adoption of this amended standard is not expected to have a material impact on the company's financial statements.

Levies

In May 2013, the IASB issued International Financial Reporting Interpretation Committee (IFRIC) 21 *Levies.* This clarifies that an entity recognizes a liability for a levy when the activity that triggers payment occurs.

For a levy that is triggered upon reaching a minimum threshold, the interpretation clarifies that no liability should be anticipated before the minimum threshold is reached. Retrospective application of this interpretation is effective for annual periods beginning on or after January 1, 2014, with earlier application permitted. The company is assessing the impact of this interpretation on royalties and property taxes.

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. In November 2013, the IASB issued amendments to include the new general hedge accounting model and to postpone the mandatory effective date of this standard indefinitely. The full impact of this standard will not be known until the amendments addressing impairments, classification and measurement have been completed. When these projects are completed, an effective date will be added by the IASB.

6. ADOPTION OF NEW AND AMENDED IFRS STANDARDS

Effective January 1, 2013, the company adopted the following new and amended IFRS standards and interpretations.

New and/or amended IFRS standards that resulted in restatements to comparative figures

Impact of the application of IFRS 11 *Joint Arrangements*

IFRS 11 establishes a principle-based approach to accounting for joint arrangements by assessing the rights and obligations of the arrangement and limits the application of proportionate consolidation accounting to arrangements where sufficient rights and obligations are passed to the partners. As a result, two existing joint arrangements in the Refining and Marketing segment were reclassified as joint ventures, and are now being accounted for using the equity

method of accounting rather than the proportionate consolidation method. This change did not have a material impact to the consolidated financial statements, but did result in the netting of revenues and expenses for these entities into Other Income, the netting of equity pick-up and cash distribution within Other in the Consolidated Statements of Cash Flows, and the company's net investment in these entities is now presented in Other Assets.

Impact of the application of IAS 19 *Employee Benefits* amendments

The revised standard resulted in changes to the calculation and presentation of pension interest cost, which is now calculated on the net unfunded obligation, applying the discount rate used to measure the employee benefit obligation at the beginning of the annual period. Previously, pension interest cost was net of interest income on plan assets (using the expected return on plan assets) and interest expense on the plan obligation (using the discount rate). The net pension interest expense was reclassified to Financing Expenses from Operating, Selling and General expense. The change to the pension interest cost calculation also resulted in the refundable tax accounts (RTA) being present valued, resulting in an immaterial adjustment to the Consolidated Balance Sheets noted below.

IFRS 11 and the amendments to IAS 19 have been applied retroactively, and the effects of the application of IFRS 11 and IAS 19 amendments on the comparative periods are shown in the tables below.

Adjustments to Consolidated Statements of Comprehensive Income(1):

	For the year ended December 31, 2012		
($ millions, increase/(decrease))	IFRS 11	IAS 19	Total
Revenues and Other Income			
Operating revenues, net of royalties	(101)	—	(101)
Other income	11	—	11
Expenses			
Purchases of crude oil and products	(54)	—	(54)
Operating, selling and general	(29)	(22)	(51)
Depreciation, depletion, amortization and impairment	(4)	—	(4)
Financing expenses	(3)	79	76
Income Taxes			
Deferred	—	(14)	(14)
Net Loss	—	(43)	(43)
Actuarial gain on employee retirement benefit plans	—	43	43
Total Comprehensive Income	—	—	—
Per Common Share (dollars)			
Basic	—	(0.03)	(0.03)
Diluted	—	(0.03)	(0.03)

(1) The impact of the IAS 19 adjustments for the year ended December 31, 2013 was an increase to Financing Expenses of $49 million with a corresponding actuarial gain of $36 million, net of income taxes of $13 million, resulting in a $nil impact to the Consolidated Statements of Comprehensive Income.

Adjustments to Consolidated Balance Sheets:

($ millions, increase/(decrease))	Dec 31 2012	Jan 1 2012
Cash and cash equivalents	(8)	(22)
Accounts receivable	(43)	(29)
Inventories	(46)	(36)
Property, plant and equipment, net	(24)	(26)
Other assets	99	102
Goodwill and other intangible assets	(24)	(25)
Deferred income taxes	(2)	—
Total assets	(48)	(36)
Short-term debt	(1)	(2)
Accounts payable and accrued liabilities	(23)	(13)
Income taxes payable	(5)	(5)
Other long-term liabilities[(2)]	9	10
Provisions	(1)	(1)
Deferred income taxes[(2)]	(19)	(17)
Shareholders' equity[(2)]	(8)	(8)
Total liabilities and shareholders' equity	(48)	(36)

(2) At December 31, 2012, the adjustment related to IAS 19 resulted in an increase of $11 million to Other long-term liabilities, offset by a decrease of $3 million and $8 million, respectively, to Deferred income taxes and Shareholders' equity. The remaining adjustments relate to IFRS 11.

Adjustments to Consolidated Statements of Cash Flow:

($ millions, increase/(decrease))	For the year ended December 31, 2012
Operating activities	
Cash flow from operating activities before change in non-cash working capital	(12)
Decrease in non-cash working capital	25
Cash flow from operating activities	13
Cash flow from investing activities	1
Cash flow from financing activities	—
Increase in cash and cash equivalents	14

Other new IFRS standards

Joint Arrangements

IFRS 12 *Disclosures of Interests in Other Entities* is a comprehensive disclosure standard for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities. The adoption of this standard had no material impact on the company's consolidated financial statements, but did result in increased disclosures on the company's material subsidiaries and interest in associates and joint arrangements. Refer to note 29 and 30.

Offsetting Financial Assets and Financial Liabilities Disclosures

IFRS 7 *Financial Instruments: Disclosures* amendments added disclosure requirements to enhance the understanding of the potential effects of offsetting arrangements. Refer to note 27.

Fair Value Measurements

IFRS 13 *Fair Value Measurement* 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. The adoption of this standard had no material impact on the company's consolidated financial statements, but did result in increased disclosures on the fair value measurement of the company's financial instruments. Refer to note 27.

Recoverable Amount Disclosures for Non-Financial Assets

The company early adopted amendments to IAS 36 *Impairment of Assets*. The amendments clarified the recoverable amount is disclosed only when an asset or CGU is impaired. The amended standard also requires expanded disclosure, including the fair value measurement input level, for CGUs with goodwill and assets that are impaired based on fair value less costs of disposal methodology. Refer to notes 10 and 20.

7. SEGMENTED INFORMATION

The company's operating segments are reported based on the nature of their products and services and management responsibility. 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 Fort Hills (40.8%) and Joslyn North (36.75%) mining projects 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. 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.

- 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 represented 10% or more of the consolidated revenues for the year ended December 31, 2013 and 2012.

For the years ended December 31 ($ millions)	Oil Sands		Exploration and Production		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
	2013	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012
Revenues and Other Income		(restated – note 6)				(restated – note 6)		(restated – note 6)		(restated – note 6)
Gross revenues	**9 063**	8 378	**5 931**	5 947	**26 495**	26 008	**109**	89	**41 598**	40 422
Intersegment revenues	**4 026**	3 124	**432**	529	**163**	212	**(4 621)**	(3 865)	**—**	—
Less: Royalties	**(859)**	(684)	**(1 146)**	(1 631)	**—**	—	**—**	—	**(2 005)**	(2 315)
Operating revenues, net of royalties	**12 230**	10 818	**5 217**	4 845	**26 658**	26 220	**(4 512)**	(3 776)	**39 593**	38 107
Other income	**64**	20	**381**	71	**22**	38	**237**	290	**704**	419
	12 294	10 838	**5 598**	4 916	**26 680**	26 258	**(4 275)**	(3 486)	**40 297**	38 526
Expenses										
Purchases of crude oil and products	**460**	211	**568**	444	**20 807**	20 341	**(4 542)**	(3 949)	**17 293**	17 047
Operating, selling and general	**5 837**	5 365	**676**	795	**2 307**	2 249	**627**	488	**9 447**	8 897
Transportation	**482**	337	**127**	182	**278**	204	**(42)**	(38)	**845**	685
Depreciation, depletion, amortization and impairment	**2 439**	3 964	**1 804**	1 857	**530**	464	**119**	161	**4 892**	6 446
Exploration	**115**	71	**207**	238	**—**	—	**—**	—	**322**	309
Gain on disposal of assets	**—**	(29)	**(130)**	(1)	**(7)**	(13)	**—**	(1)	**(137)**	(44)
Project start-up costs	**15**	57	**—**	—	**—**	3	**—**	—	**15**	60
Voyageur upgrader project charges	**82**	—	**—**	—	**—**	—	**—**	—	**82**	—
Financing expenses (income)	**135**	127	**33**	81	**5**	2	**989**	(68)	**1 162**	142
	9 565	10 103	**3 285**	3 596	**23 920**	23 250	**(2 849)**	(3 407)	**33 921**	33 542
Earnings (Loss) before Income Taxes	**2 729**	735	**2 313**	1 320	**2 760**	3 008	**(1 426)**	(79)	**6 376**	4 984
Income Taxes										
Current	**331**	1	**1 443**	1 154	**674**	342	**(365)**	18	**2 083**	1 515
Deferred	**358**	266	**(130)**	28	**64**	529	**90**	(94)	**382**	729
	689	267	**1 313**	1 182	**738**	871	**(275)**	(76)	**2 465**	2 244
Net Earnings (Loss)	**2 040**	468	**1 000**	138	**2 022**	2 137	**(1 151)**	(3)	**3 911**	2 740
Capital and Exploration Expenditures	**4 311**	4 957	**1 483**	1 261	**890**	644	**93**	95	**6 777**	6 957

Geographical Information

Operating Revenues, net of Royalties

($ millions)	**2013**	2012

		(restated – note 6)
Canada	**31 407**	30 074
Foreign	**8 186**	8 033
	39 593	38 107

Non-Current Assets[1]

($ millions)	Dec 31 2013	Dec 31 2012	Jan 1 2012
		(restated – note 6)	(restated – note 6)
Canada	**57 235**	55 817	53 845
Foreign	**6 321**	6 424	6 799
	63 556	62 241	60 644

(1) Excludes deferred income tax assets.

8. OTHER INCOME

Other Income consists of the following:

($ millions)	2013	2012
		(restated – note 6)
Energy trading activities		
Change in fair value of contracts	**176**	246
Gains (losses) on inventory valuation	**15**	(13)
Risk management activities	**(18)**	1
Risk mitigation and insurance proceeds	**342**	27
Investment and interest income	**85**	91
Renewable energy grants	**47**	59
Change in value of pipeline commitments and other	**57**	8
	704	419

9. OPERATING, SELLING AND GENERAL

Operating, Selling and General expense consists of the following:

($ millions)	2013	2012
		(restated – note 6)
Contract services	**4 412**	4 067
Employee costs[1]	**2 654**	2 664
Materials	**932**	720
Energy	**915**	608
Equipment rentals and leases	**335**	329
Travel, marketing and other	**199**	509
	9 447	8 897

(1) The company incurred $3.3 billion of employee costs for the year ended December 31, 2013 (2012 – $3.2 billion), of which $2.7 billion (2012 – $2.7 billion) was recorded as employee benefits in Operating, Selling and General expense. Employee costs includes salaries, benefits and share-based compensation.

10. ASSET IMPAIRMENT

All impairments and impairment reversals were recorded as part of Depreciation, Depletion, Amortization and Impairment expense. Asset impairments during the period are as follows.

Exploration and Production

Libya

Political unrest in Libya resulted in the closure of export terminal operations at certain Libyan seaports in late July 2013 and production was essentially shut-in for the last five months of 2013. As a result, the company performed an impairment test on its Libyan assets using a value-in-use methodology to determine the recoverable amount, and an after-tax impairment charge of $101 million was recognized in the fourth quarter of 2013 and charged against Property, Plant and Equipment.

The impairment test used an expected cash flow approach based on 2013 year-end reserves data with a risk-adjusted discount rate of 17% to reflect uncertainty related to continued political unrest in the region, with three scenarios representing i) future cash flows based on the 2013 year-end reserves information, ii) future operations incorporating the company's strategic growth plan, and iii) suspension of all activity at the end of 2014. The first two scenarios were equally weighted at 45% each and the final scenario was assigned a weighting of 10% based on the company's best estimates. All scenarios incorporated the restart of production on April 1, 2014 and were based on an average price of US$104.00 per barrel through 2014 – 2019 escalated at an average of 2% per year thereafter.

The calculation of the recoverable amount is sensitive to the likelihood and timing of production restart, the discount rate, and prices. A three-month delay in the resumption of production restart would impact after-tax earnings by approximately $50 million. A 2% change in discount rate would impact after-tax earnings by approximately $80 million. A 5% change in price would impact after-tax earnings by approximately $75 million.

The remaining carrying value of the company's net assets in Libya as at December 31, 2013 was approximately $570 million.

Syria

Since December 2011, the company's operations and its contractual obligations in Syria have been suspended under a period of force majeure due to political unrest and international sanctions affecting that country. As there has been no resolution of the political situation and increasing uncertainty with respect to the company's return to operations in the country, during the fourth quarter of 2013, using a value-in-use methodology, the company impaired the remaining carrying value of its Syrian property, plant and equipment and working capital, resulting in an after-tax impairment charge of $422 million. The company also recognized $300 million ($223 million after-tax) of risk mitigation proceeds in Other Income that had been received in the fourth quarter of 2012 as the likelihood of return in the foreseeable future is remote. These proceeds are subject to a provisional repayment should the company recover any or all of its investment in Syria.

In the second quarter of 2012, the company recognized after-tax impairment charges and a bad debt provision of $694 million related to its Syrian assets. An impairment test was performed since there was no resolution to the political situation and international sanctions continued to affect the country. The impairment losses were charged against Property, Plant and Equipment ($604 million) and other current assets ($23 million). The company also recognized a bad debt provision for the remainder of its Syrian receivables ($67 million).

In the fourth quarter of 2012, a valuation assessment was performed. After receipt of the $300 million of risk mitigation proceeds, an impairment reversal of $177 million was recorded.

Other

In the fourth quarter of 2013, the company recognized an after-tax impairment charge of $40 million to reflect the recoverable amount of its unconventional oil properties in the Wilson Creek area of central Alberta. The recoverable amount was determined using a fair value less costs of disposal methodology, with the expected cash flow approach based on 2013 year-end reserves information and a risk-adjusted discount rate of 10% (Level 3 fair value inputs).

In 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 as a result of future

development uncertainty. In addition, the company also recognized an after-tax impairment charge of $63 million related to certain natural gas properties due to a decline in price forecasts.

Oil Sands

Voyageur Upgrader Project

In the fourth quarter of 2012, the company recognized after-tax impairment charges of $1.487 billion related to its 51% interest in the Voyageur upgrader project. As a result of the challenging economic outlook for the Voyageur upgrader, an impairment test was performed at December 31, 2012, using a fair value less costs of disposal methodology. A risk-adjusted discount rate of 10% was used to perform the calculation.

11. FINANCING EXPENSES

($ millions)	2013	2012
		(restated – note 6)
Interest on debt and finance leases	**703**	640
Capitalized interest at 6.1% (2012 – 6.0%)	**(397)**	(587)
Interest expense	**306**	53
Interest on pension and other post-retirement benefits	**68**	79
Accretion	**192**	182
Foreign exchange loss (gain) on U.S. dollar denominated debt	**605**	(181)
Foreign exchange and other	**(9)**	9
	1 162	142

12. INCOME TAXES

Income Tax Expense

($ millions)	2013	2012
		(restated – note 6)
Current:		
Current year	**2 093**	1 483
Adjustments for prior years	**(10)**	32
Deferred:		
Origination and reversal of temporary differences	**410**	687
Adjustments for prior years	**(28)**	(46)
Changes in tax rates and legislation	**—**	88
	2 465	2 244

There was no income tax recognized directly in equity during 2013 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)	**2013**	2012
		(restated – note 6)
Earnings before income tax	**6 376**	4 984
Canadian statutory tax rate	**25.64%**	25.67%
Statutory tax	**1 635**	1 279
Add (deduct) the tax effect of:		
Non-taxable component of capital gains and losses	**71**	(22)
Share-based compensation and other permanent items	**5**	15
Assessments and adjustments	**(38)**	—
Impact of income tax rate and legislative changes [1]	**—**	88
Canadian tax rate differential	**4**	1
Foreign tax rate differential	**691**	763
Non-taxable impairment charge	**134**	127
Other	**(37)**	(7)
	2 465	2 244

(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.

Deferred Income Tax Balances

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

	Consolidated Statements of Comprehensive Income		Consolidated Balance Sheets [2]		
($ millions)	**2013**	2012	**Dec 31 2013**	Dec 31 2012	Jan 1 2012
		(restated – note 6)		(restated – note 6)	(restated – note 6)
Property, plant and equipment	**758**	1 266	**12 134**	11 991	10 725
Decommissioning and restoration provision	**(54)**	(625)	**(1 017)**	(1 132)	(507)
Employee retirement benefit plans	**(103)**	(69)	**(541)**	(636)	(521)
Tax loss carry-forwards	**136**	391	**(31)**	(167)	(558)
Partnership deferral reserve	**(213)**	(189)	**192**	405	594
Other	**(142)**	(45)	**(18)**	(95)	(91)
	382	729	**10 719**	10 366	9 642

(2) The current and non-current portion of the deferred income tax liability and asset are as follows:

($ millions)	Dec 31 2013	Dec 31 2012	Jan 1 2012
		(restated – note 6)	(restated – note 6)
Current deferred income tax liability	**103**	141	6
Current deferred income tax asset	**(4)**	(9)	(13)
Non-current deferred income tax liability	**10 681**	10 303	9 696
Non-current deferred income tax asset	**(61)**	(69)	(47)
Net deferred income tax liability	**10 719**	10 366	9 642

Change in Deferred Income Tax Balances

($ millions)	2013	2012
		(restated – note 6)
Beginning of year	**10 366**	9 642
Recognized in deferred income tax expense	**382**	729
Recognized in other comprehensive income	**201**	(49)
Foreign exchange, disposition, and other	**(230)**	44
End of year	**10 719**	10 366

No deferred tax liability has been recognized at December 31, 2013 on temporary differences of approximately $11.2 billion (2012 – $9.9 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.

Canada Revenue Agency Proposal Letter

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 certain derivative contracts. Following the company's response to the letter and subsequent information requests in 2013, CRA informed the company that it has not changed its original proposed position.

In the event that the CRA issues a formal Notice of Reassessment (NOR), the company plans to file a Notice of Objection to dispute this matter. However, notwithstanding the filing of an objection, 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.

The company strongly disagrees with the CRA's position and 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. If the company is unsuccessful in defending its tax filing position, it could be subject to an earnings impact of up to $1.2 billion.

13. EARNINGS PER COMMON SHARE

($ millions)	2013	2012
		(restated – note 6)
Net earnings	**3 911**	2 740
Dilutive impact of accounting for awards as equity-settled [1]	**—**	(7)
Net earnings – diluted	**3 911**	2 733
(millions of common shares)		
Weighted average number of common shares	**1 501**	1 545
Dilutive securities:		
Effect of share options	**1**	4
Weighted average number of diluted common shares	**1 502**	1 549
(dollars per common share)		
Basic earnings per share	**2.61**	1.77
Diluted earnings per share	**2.60**	1.76

(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 year ended December 31, 2012.

14. CASH AND CASH EQUIVALENTS

($ millions)	Dec 31 2013	Dec 31 2012	Jan 1 2012
		(restated – note 6)	(restated – note 6)
Cash	**1 184**	628	810
Cash equivalents	**4 018**	3 757	2 971
	5 202	4 385	3 781

15. SUPPLEMENTAL CASH FLOW INFORMATION

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

($ millions)	2013	2012
		(restated – note 6)
Accounts receivable	**(60)**	193
Inventories	**(220)**	460
Accounts payable and accrued liabilities	**69**	(1 729)
Current portion of provisions	**206**	45
Income taxes payable (net)	**603**	106
	598	(925)
Relating to:		
Operating activities	**688**	(874)
Investing activities	**(90)**	(51)

16. INVENTORIES

($ millions)	Dec 31 2013	Dec 31 2012	Jan 1 2012
		(restated – note 6)	(restated – note 6)
Crude oil	**1 269**	1 091	1 321
Refined products	**1 695**	1 523	1 705
Materials, supplies and merchandise	**594**	597	592
Energy trading commodity inventories	**386**	486	551
	3 944	3 697	4 169

During 2013, product inventories of $18.0 billion (2012 – $17.7 billion) were expensed. There was no inventory write-down during 2013 (2012 – $45 million).

17. PROPERTY, PLANT AND EQUIPMENT

($ millions)	Oil and Gas Properties	Plant and Equipment	Total
			(restated – note 6)
Cost			
At January 1, 2012	20 289	45 107	65 396
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	49 914	74 368
Additions	**2 094**	**4 475**	**6 569**
Transfers from exploration and evaluation	**644**	**—**	**644**
Acquisitions (note 33)	**—**	**374**	**374**
Changes in decommissioning and restoration	**358**	**18**	**376**
Disposals	**(2 578)**	**(921)**	**(3 499)**
Foreign exchange adjustments	**551**	**166**	**717**
At December 31, 2013	**25 523**	**54 026**	**79 549**
Accumulated provision			
At January 1, 2012	(4 706)	(8 127)	(12 833)
Depreciation and depletion	(1 634)	(2 058)	(3 692)
Impairment (note 10)	(204)	(2 484)	(2 688)
Impairment reversal (note 10)	34	143	177
Disposals	42	57	99
Foreign exchange adjustments	(25)	28	3
At December 31, 2012	(6 493)	(12 441)	(18 934)
Depreciation and depletion	**(2 056)**	**(2 181)**	**(4 237)**
Impairment (note 10)	**(155)**	**(444)**	**(599)**
Disposals	**997**	**744**	**1 741**
Foreign exchange adjustments	**(189)**	**(61)**	**(250)**
At December 31, 2013	**(7 896)**	**(14 383)**	**(22 279)**
Net property, plant and equipment			
December 31, 2012	17 961	37 473	55 434
December 31, 2013	**17 627**	**39 643**	**57 270**

($ millions)	Dec 31, 2013 Cost	Accumulated provision	Net book value	Dec 31, 2012 Cost	Accumulated provision	Net book value
						(restated – note 6)
Oil Sands	**52 127**	**(12 125)**	**40 002**	47 337	(10 440)	36 897
Exploration and Production	**15 660**	**(6 704)**	**8 956**	16 335	(5 691)	10 644
Refining and Marketing	**10 449**	**(2 883)**	**7 566**	9 462	(2 355)	7 107
Corporate, Energy Trading and Eliminations	**1 313**	**(567)**	**746**	1 234	(448)	786
	79 549	**(22 279)**	**57 270**	74 368	(18 934)	55 434

At December 31, 2013, the balance of assets under construction, and not subject to depreciation or depletion, was $11.1 billion (December 31, 2012 – $12.2 billion; January 1, 2012 – $16.2 billion).

At December 31, 2013, Property, Plant and Equipment included finance leases with a net book value of $997 million (December 31, 2012 – $831 million; January 1, 2012 – $425 million).

Fort Hills Project Sanction

On October 30, 2013, the co-owners of Fort Hills announced project sanction. As a result, the accumulated capital costs in exploration and evaluation assets were transferred to oil and gas properties in Property, Plant and Equipment and an impairment test was required in accordance with IFRS 6 *Exploration for and Evaluation of Mineral Resources* . A fair value less costs of disposal methodology was used to determine the recoverable amount and, as it exceeded the carrying amount, no impairment was recorded. Key assumptions used in the calculation of the recoverable amount were bitumen price, future capital costs and discount rate. The assumptions used by management to calculate the recoverable amount may change. Changes in these assumptions will have an impact on the recoverable amount and may result in impairment.

For purposes of calculating the recoverable amount at the date of sanction, the company applied a risk-adjusted discount rate of 8%, assumed bitumen price of $64.00 per barrel at first oil in 2017, escalated at an average of 2% per year thereafter, for the remaining life of the mine, and go forward capital costs of $5.5 billion (Level 3 fair value inputs).

A 1% increase in discount rate would have resulted in a decrease to the recoverable amount of $1.0 billion. Bitumen prices were based on third party published price curves adjusted for the company's view on long-term pricing economics and marketing information. A 5% decrease in prices would have resulted in a decrease to the recoverable amount of $800 million. Future capital costs of the mine are derived from company experience and adjusted for specific attributes of the project and expected cost savings due to new technologies. A 15% increase to this estimate (over the construction period) would have resulted in a decrease to the recoverable amount of $700 million.

18. EXPLORATION AND EVALUATION ASSETS

($ millions)	2013	2012
Beginning of year	**3 284**	4 554
Additions	**225**	478
Transfers to oil and gas assets	**(644)**	(1 598)
Dry hole expenses	**(82)**	(145)
Disposals	**(11)**	—
Impairment	**—**	(88)
Amortization	**(13)**	(24)
Foreign exchange adjustments	**13**	107
End of year	**2 772**	3 284

19. OTHER ASSETS

($ millions)	Dec 31 2013	Dec 31 2012	Jan 1 2012
		(restated – note 6)	(restated – note 6)
Investments	**325**	309	265
Prepaids and other	**97**	110	148
	422	419	413

20. GOODWILL AND OTHER INTANGIBLE ASSETS

	Oil Sands	Refining and Marketing			
($ millions)	Goodwill	Goodwill	Brand name	Customer lists	Total
		(restated – note 6)			(restated – note 6)
At January 1, 2012	2 752	149	166	47	3 114
Derecognition of goodwill	—	(1)	—	—	(1)
Additions	—	—	—	5	5
Amortization	—	—	—	(14)	(14)
At December 31, 2012	2 752	148	166	38	3 104
Amortization	**—**	**—**	**—**	**(12)**	**(12)**
At December 31, 2013	**2 752**	**148**	**166**	**26**	**3 092**

The company performed its most recent goodwill impairment test at October 31, 2013. Recoverable amounts for the Oil Sands CGUs were based on fair value less costs of disposal 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 (Level 3 fair value inputs).

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 discounted using after-tax risk-adjusted discount rates. The discount rates are 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 October 31, 2013 (July 31, 2012 – 10%). The company based its cash flow projections on an average West Texas Intermediate (WTI) price of US$ 97.50 per barrel through 2014-2019 escalated at an average of 2% per year thereafter, adjusted for applicable quality and location differentials depending on the underlying CGU. The forecasted cash flow period ranged from 20 years to 55 years based on the reserve life of the respective CGU. 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 October 31, 2013 of its Refining and Marketing operating segment, and no impairment was identified within the operating segment or the associated allocated goodwill.

21. DEBT AND CREDIT FACILITIES

Debt and credit facilities are comprised of the following:

Short-Term Debt

($ millions)	Dec 31 2013	Dec 31 2012	Jan 1 2012
		(restated – note 6)	(restated – note 6)
Commercial paper [1]	**798**	775	761

(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, 2013 was 0.3% (December 31, 2012 – 0.4%; January 1, 2012 – 0.4%).

Long-Term Debt

($ millions)	Dec 31 2013	Dec 31 2012	Jan 1 2012
Fixed-term debt, redeemable at the option of the company			
6.85% Notes, due 2039 (US$750)	**798**	746	763
6.80% Notes, due 2038 (US$900)	**983**	921	942
6.50% Notes, due 2038 (US$1150)	**1 223**	1 144	1 170
5.95% Notes, due 2035 (US$600)	**596**	556	566
5.95% Notes, due 2034 (US$500)	**532**	498	509
5.35% Notes, due 2033 (US$300)	**279**	259	263
7.15% Notes, due 2032 (US$500)	**532**	498	509
6.10% Notes, due 2018 (US$1250)	**1 330**	1 244	1 271
6.05% Notes, due 2018 (US$600)	**646**	606	621
5.00% Notes, due 2014 (US$400)	**427**	402	413
4.00% Notes, due 2013 (US$300)	**—**	299	305
7.00% Debentures, due 2028 (US$250)	**274**	256	263
7.875% Debentures, due 2026 (US$275)	**321**	303	312
9.25% Debentures, due 2021 (US$300)	**378**	361	376
5.39% Series 4 Medium Term Notes, due 2037	**600**	600	600
5.80% Series 4 Medium Term Notes, due 2018	**700**	700	700
Total unsecured long-term debt	**9 619**	9 393	9 583
Secured long-term debt	**13**	13	13
Finance leases [2]	**1 071**	894	476
Deferred financing costs	**(43)**	(51)	(56)
	10 660	10 249	10 016
Current portion of long-term debt			
Finance leases	**(17)**	(12)	(12)
Secured long-term debt	**(13)**	—	—

4.00% Notes, due July 2013 (US$300)	**—**	(299)	—
5.00% Notes, due 2014 (US$400)	**(427)**	—	—
	(457)	(311)	(12)
Total long-term debt	**10 203**	9 938	10 004

(2) Interest rates range from 4.6% to 13.4% and maturity dates range from 2017 to 2052.

Scheduled Debt Repayments

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

($ millions)	Repayment
2014	1 255
2015	22
2016	24
2017	23
2018	2 690
Thereafter	7 437
	11 451

Credit Facilities

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

($ millions)	**2013**
Fully revolving for a period of one year after term-out date (Nov 2014)	**2 000**
Fully revolving and expires in 2015	**900**
Fully revolving for a period of three years and expires in 2016	**3 000**
Can be terminated at any time at the option of the lenders	**288**
Total credit facilities	**6 188**
Credit facilities supporting outstanding commercial paper	**(798)**
Credit facilities supporting standby letters of credit [3]	**(854)**
Total unutilized credit facilities	**4 536**

(3) The company supported certain credit facilities with $585 million of cash collateral as at December 31, 2013 (December 31, 2012 – $150 million).

22. OTHER LONG-TERM LIABILITIES

($ millions)	**Dec 31 2013**	Dec 31 2012	Jan 1 2012
		(restated – note 6)	(restated – note 6)
Pensions and other post-retirement benefits (note 23)	**926**	1 645	1 694
Share-based compensation plans (note 26)	**335**	242	187
Deferred revenue	**72**	77	84
Fort Hills purchase obligation [1]	**—**	223	275
Libya EPSAs signature bonus [2]	**64**	72	73
Other	**67**	60	89
	1 464	2 319	2 402

(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, 2013, the carrying amount of the Fort Hills obligation, based on the discounted estimated payout pattern for the funding, was $230 million (December 31, 2012 – $300 million), of which the entire portion is classified as current (December 31, 2012 – $77 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 2014. At December 31, 2013, the carrying amount of the Libya EPSAs signature bonus was $78 million (December 31, 2012 – $86 million). The current portion is $14 million (December 31, 2012 – $14 million) and is recorded in Accounts Payable and Accrued Liabilities.

23. 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.

Asset-Liability matching studies are performed by a third-party consultant to set the asset mix by quantifying the risk-and-return characteristics of possible asset mix strategies. Investment and contribution policies are integrated within this study, and areas of focus include asset mix as well as interest rate sensitivity.

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, 2013. 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.

Effective January 1, 2014, Petro-Canada Retirement Plan and Suncor Energy Pension Plan were merged. There was no impact to the consolidated results as a result of this transaction.

Defined Benefit Obligations and Funded Status

($ millions)	Pension Benefits 2013	Pension Benefits 2012	Other Post-Retirement Benefits 2013	Other Post-Retirement Benefits 2012
		(restated – note 6)		
Change in benefit obligation				
Benefit obligation at beginning of year	**4 137**	3 698	**545**	510
Current service costs	**160**	143	**13**	11
Past service costs	**13**	—	**—**	—
Plan participants' contributions	**14**	14	**—**	—
Benefits paid	**(186)**	(172)	**(16)**	(18)
Interest costs	**159**	163	**21**	22
Foreign exchange	**17**	2	**2**	—
Settlements	**2**	2	**—**	—
Actuarial remeasurement:				
Experience loss (gain) arising on plan liabilities	**25**	18	**(5)**	(13)
Actuarial loss (gain) arising from changes in demographic assumptions	**38**	—	**(1)**	—
Actuarial (gain) loss arising from changes in financial assumptions	**(488)**	269	**(70)**	33
Benefit obligation at end of year	**3 891**	4 137	**489**	545
Change in plan assets				
Fair value of plan assets at beginning of year	**2 832**	2 488	**—**	—
Employer contributions	**220**	267	**—**	—
Plan participants' contributions	**14**	14	**—**	—
Benefits paid	**(178)**	(172)	**—**	—
Foreign exchange	**14**	3	**—**	—
Settlements	**2**	2	**—**	—
Administrative costs	**(2)**	—	**—**	—
Interest income on plan assets	**112**	106	**—**	—
Actuarial remeasurement:				
Return on plan assets (excluding amounts included in net interest expense)	**279**	124	**—**	—
Fair value of plan assets at end of year	**3 293**	2 832	**—**	—
Net unfunded obligation	**598**	1 305	**489**	545

Of the total net unfunded obligation as at December 31, 2013, 86% relates to Canadian pension and other post-retirement benefits obligation (excluding Syncrude) (December 31, 2012 – 88%). The weighted average duration of the Canadian pension and other post-retirement plans (excluding Syncrude) is 14.0 years (2012 – 14.2 years).

The net unfunded obligation is recorded in Accounts Payable and Accrued Liabilities and Other Long-Term Liabilities (note 22) in the Consolidated Balance Sheets.

($ millions)	Pension Benefits 2013	Pension Benefits 2012	Other Post-Retirement Benefits 2013	Other Post-Retirement Benefits 2012
		(restated – note 6)		
Analysis of amount charged to earnings:				
Current service costs	**160**	143	**13**	11
Past service costs	**13**	—	**—**	—
Interest costs	**47**	57	**21**	22
Defined benefit plans expense	**220**	200	**34**	33
Defined contribution plans expense	**62**	53	**—**	—
Total benefit plans expense charged to earnings	**282**	253	**34**	33

Components of defined benefit costs recognized in Other Comprehensive Income:

($ millions)	Pension Benefits 2013	Pension Benefits 2012	Other Post-Retirement Benefits 2013	Other Post-Retirement Benefits 2012
		(restated – note 6)		
Return on plan assets (excluding amounts included in net interest expense)	**(279)**	(124)	**—**	—
Experience loss (gain) arising on plan liabilities	**25**	18	**(5)**	(13)
Actuarial loss (gain) arising from changes in demographic assumptions	**38**	—	**(1)**	—
Actuarial (gain) loss arising from changes in financial assumptions	**(488)**	269	**(70)**	33
Actuarial (gain) loss recognized in other comprehensive income	**(704)**	163	**(76)**	20

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 Dec 31 2013	Pension Benefits Dec 31 2012	Other Post-Retirement Benefits Dec 31 2013	Other Post-Retirement Benefits Dec 31 2012
Discount rate	**4.70**	3.90	**4.70**	3.90
Rate of compensation increase	**3.45**	3.65	**3.30**	3.75

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

The defined benefit obligation reflects the best estimate of the mortality of plan participants both during and after their employment. The mortality assumption is based on a standard mortality table adjusted for actual experience over the past five years.

In order to measure the expected cost of other post-retirement benefits, it was assumed for 2013 that the health care costs would increase annually by 7% per person (2012 – 7%). This rate will remain constant in 2014 and will decrease 0.5% annually to 5% by 2018, and remain at that level thereafter.

Assumed discount rates, longevity rates and health care cost trend rates may have a significant effect on the amounts reported for pensions and other post-retirement benefit obligations for the company's Canadian plans (excluding Syncrude). A 1% change of these assumed assumptions would have the following effects:

	Pension Benefits	
($ millions)	Increase	Decrease
Discount rate		
Effect on the aggregate service and interest costs	(13)	16
Effect on the benefit obligations	(411)	514
Longevity rate		
Effect on the aggregate service and interest costs	6	(6)
Effect on the benefit obligations	79	(82)

	Other Post-Retirement Benefits	
($ millions)	Increase	Decrease
Discount rate		
Effect on the benefit obligations	(56)	70
Health care cost		
Effect on the aggregate service and interest costs	2	(1)
Effect on the benefit obligations	32	(27)

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:

(%)	**2013**	2012
Equities, comprised of:		
– Canada	**18**	18
– United States	**22**	20
– Foreign	**20**	20
	60	58
Fixed income, comprised of:		
– Canada	**40**	42
Total	**100**	100

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

The company expects to make cash contributions to its defined benefit pension plans in 2014 of $427 million.

24. PROVISIONS

($ millions)	Decommissioning and Restoration[1]	Royalties[2]	Other[3]	Total
			(restated – note 6)	(restated – note 6)
At January 1, 2012	3 801	355	406	4 562
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	733	5 788
Less: current portion	(395)	(367)	(94)	(856)
	4 293	—	639	4 932
At December 31, 2012	4 688	367	733	5 788
Liabilities incurred	**398**	**224**	**97**	**719**
Changes in estimates	**82**	**(15)**	**(392)**	**(325)**
Liabilities settled	**(423)**	**(52)**	**(132)**	**(607)**
Accretion	**174**	**—**	**5**	**179**
Asset divestitures	**(714)**	**—**	**—**	**(714)**
Foreign exchange	**33**	**—**	**3**	**36**
At December 31, 2013	**4 238**	**524**	**314**	**5 076**
Less: current portion	**(362)**	**(524)**	**(112)**	**(998)**
	3 876	**—**	**202**	**4 078**

(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, 2013 was approximately $8.0 billion (December 31, 2012 – $8.1 billion). A weighted average credit-adjusted risk-free interest rate of 4.51% was used to discount the provision recognized at December 31, 2013 (December 31, 2012 – 3.75%). The credit-adjusted risk-free rate used reflects the expected time frame 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 December 2013, Suncor reached an agreement with the Government of Alberta concerning several outstanding issues under the Royalty Amending Agreements (RAA) entered into in 2008. Subsequent to December 31, 2013, the company settled $196 million related to these provisions.

(3) For the year ended December 31, 2013, the company's provisions decreased by $300 million as a result of a recognition of risk mitigation proceeds to earnings. In addition, the company divested one of its pipeline commitments to a third party, resulting in a $76 million decrease to provisions.

25. 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

Pursuant to the company's normal course issuer bid (the 2012 NCIB) that commenced in the third quarter of 2012, the company repurchased a total of 38.9 million common shares for a total consideration of $1.2 billion. Under the 2012 NCIB, the company repurchased 25.1 million common shares during 2013 for total consideration of $781 million.

On August 5, 2013, the company commenced a new normal course issuer bid (the 2013 NCIB) through the facilities of the Toronto Stock Exchange, New York Stock Exchange and/or alternative trading platforms. The 2013 NCIB was amended on February 3, 2014 to permit the company to purchase for cancellation additional shares. Pursuant to the 2013 NCIB, the company is permitted to purchase for cancellation up to approximately $2.8 billion worth of its common shares between August 5, 2013 and August 4, 2014, of which the company had repurchased a total of 24.4 million common shares for a total consideration of $894 million as at December 31, 2013.

During the year ended December 31, 2013, the company purchased 49.5 million (2012 – 46.9 million) common shares for total consideration of $1,675 million (2012 – $1,451 million). Of the amount recognized, $648 million (2012 – $609 million, net of $1.3 million options premiums) was charged to share capital and $1,027 million (2012 – $842 million) to retained earnings.

The company had also recorded a liability of $306 million at December 31, 2013 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, $108 million was charged to share capital and $198 million to retained earnings.

26. SHARE-BASED COMPENSATION

Equity-Settled 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.

(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.

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:

	2013	2012
Annual dividend per share	**$0.73**	$0.50
Risk-free interest rate	**1.40%**	1.26%
Expected life	**5 years**	5 years
Expected volatility	**48%**	50%
Weighted average fair value per option	**$11.72**	$13.30

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.

(ii) Discontinued Plans

The following plans were in place prior to August 1, 2009: SunShare 2012 Performance Stock Options, Executive Stock Options, and Key Contributor 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.

Cash-Settled Plans

(a) Cash-Settled Stock Option Plans

Stock options that the holder can settle for cash or common shares are accounted for as cash-settled 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:

	2013		2012	
	Number (thousands)	**Weighted Average Exercise Price ($)**	Number (thousands)	Weighted Average Exercise Price ($)
Outstanding, beginning of year	**47 324**	**38.33**	59 178	35.25
Granted	**4 209**	**32.50**	5 101	34.50
Exercised	**(4 750)**	**23.31**	(10 803)	17.31
Forfeited/expired	**(11 786)**	**45.13**	(6 152)	42.08
Outstanding, end of year	**34 997**	**37.47**	47 324	38.33
Exercisable, end of year	**27 104**	**38.31**	29 834	36.23

Options are exercised regularly throughout the year. Therefore, the weighted average share price during the year of $33.66 (2012 – $31.94) is representative of the weighted average share price at the date of exercise.

For the options outstanding at December 31, 2013, 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	1 885	2
20.00-29.99	1 793	3
30.00-39.99	16 066	4
40.00-49.99	14 423	3
50.00-59.99	684	1
60.00-72.17	146	1
Total	34 997	3

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

(thousands)	2013	2012
	29 817	7 020

(b) Share Unit Plans

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

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

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

A deferred share unit (DSU) is redeemable for cash or a common share for a period of time after a unitholder ceases employment or Board membership. The DSU plan is limited to executives and members of the Board of Directors. Members of the Board of Directors receive one-half or, at their option, all of their compensation in the form of DSUs. Executives may elect to receive one-half, or all, of their annual incentive payment in the form of DSUs.

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

(thousands)	PSU	RSU	DSU
Outstanding, January 1, 2012	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
Granted	**1 082**	**7 365**	**165**
Redeemed for cash	**(1 684)**	**(2 526)**	**(764)**
Forfeited/expired	**(135)**	**(658)**	**—**
Outstanding, December 31, 2013	**3 641**	**17 046**	**1 038**

(c) 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:

	2013		2012	
	Number (thousands)	**Weighted Average Exercise Price ($)**	Number (thousands)	Weighted Average Exercise Price ($)
Outstanding, beginning of year	**7 776**	**29.65**	8 752	29.32
Granted	**88**	**32.60**	101	34.51
Exercised	**(1 567)**	**27.57**	(482)	20.53
Forfeited/expired	**(492)**	**35.47**	(595)	32.86
Outstanding, end of year	**5 805**	**29.75**	7 776	29.65
Exercisable, end of year	**5 665**	**29.61**	6 568	30.80

Share-Based Compensation Expense

The following table summarizes the share-based compensation expense recorded for all plans within Operating, Selling and General expense.

($ millions)	**2013**	2012
Equity-settled plans	**51**	83
Cash-settled plans	**341**	269
Total share-based compensation expense	**392**	352

Liability Recognized for Share-Based Compensation

The company has recorded a liability of $653 million as at December 31, 2013 (December 31, 2012 – $523 million), of which $318 million was classified as current (December 31, 2012 – $281 million), based on the fair value of awards accounted for as cash-settled. The intrinsic value of the vested awards at December 31, 2013 was $347 million (December 31, 2012 – $237 million).

27. 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 company's long-term debt and long-term financial liabilities are recorded at amortized cost using the effective interest method. At December 31, 2013, the carrying value of fixed-term debt accounted for under amortized cost was $9.6 billion (December 31, 2012 – $9.4 billion) and the fair value at December 31, 2013 was $11.2 billion (December 31, 2012 – $11.8 billion). The estimated fair value of long-term debt is based on pricing sourced from market data, which is considered Level 2 fair value inputs.

Derivative Financial Instruments

(a) Non-Designated Derivative Financial Instruments

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

- Risk Management Derivatives – The company periodically enters into derivative contracts in order to manage exposure to commodity price and foreign exchange movements and are a component of the company's overall risk management program.

The Changes in the fair value of non-designated Energy Trading and Risk Management derivatives are as follows:

($ millions)	Energy Trading	Risk Management	Total
Fair value of contracts outstanding at January 1, 2012	(34)	—	(34)
Fair value of contracts realized in earnings during the year	(255)	(2)	(257)
Changes in fair value during the year (note 8)	246	1	247
Fair value of contracts outstanding at December 31, 2012	(43)	(1)	(44)
Fair value of contracts realized in earnings during the year	**(271)**	**18**	**(253)**
Changes in fair value during the year (note 8)	**176**	**(18)**	**158**
Fair value of contracts outstanding at December 31, 2013	**(138)**	**(1)**	**(139)**

(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 transactions consist of instruments with a fair value determined by an unadjusted quoted price in an active market for identical assets or liabilities. An active market is characterized by readily and regularly available quoted prices where the prices are representative of actual and regularly occurring market transactions to assure liquidity.

- Level 2 transactions consist of instruments with a fair value that is determined by quoted prices in an inactive market, prices with observable inputs, or prices with insignificant non-observable inputs. The fair value of these positions are determined using observable inputs from exchanges, pricing services, third-party independent broker quotes, and published transportation tolls. The observable inputs may be adjusted using certain methods, which include extrapolation over the quoted price term and quotes for comparable assets and liabilities.

- Level 3 transactions consist of instruments with a fair value that is determined by prices with significant unobservable inputs. As at December 31, 2013, the company does not have any derivative instruments measured at fair value Level 3.

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, 2013 and 2012.

($ millions)	Level 1	Level 2	Level 3	Total Fair Value
Accounts receivable	5	47	1	53
Accounts payable	(12)	(85)	—	(97)
Balance at December 31, 2012	(7)	(38)	1	(44)
Accounts receivable	**137**	**88**	**—**	**225**
Accounts payable	**(165)**	**(199)**	**—**	**(364)**
Balance at December 31, 2013	**(28)**	**(111)**	**—**	**(139)**

During the year ended December 31, 2013, there were no transfers between Level 1 and Level 2 fair value measurements.

The following table presents the company's recurring Level 3 derivative financial instrument assets and liabilities as at December 31, 2013 and 2012:

($ millions)	Level 3 Fair Value
Balance at December 31, 2012	1
Realized gains	2
Purchases	(7)
Transfers into Level 2	4
Balance at December 31, 2013	—

Offsetting Financial Assets and Liabilities

The company enters into arrangements that allow for offsetting of derivative financial instruments and accounts receivable (payable), which are presented on a net basis on the balance sheet, as shown in the table below as at December 31, 2013 and 2012.

Financial Assets

($ millions)	Gross assets	Gross liabilities offset	Net amounts presented
Derivatives	440	(387)	53
Accounts receivable	2 567	(732)	1 835
Balance at December 31, 2012	3 007	(1 119)	1 888
Derivatives	**225**	**(185)**	**40**
Accounts receivable	**3 092**	**(967)**	**2 125**
Balance at December 31, 2013	**3 317**	**(1 152)**	**2 165**

Financial Liabilities

($ millions)	Gross liabilities	Gross assets offset	Net amounts presented
Derivatives	(484)	387	(97)
Accounts payable	(2 401)	732	(1 669)
Balance at December 31, 2012	(2 885)	1 119	(1 766)
Derivatives	**(364)**	**185**	**(179)**
Accounts payable	**(2 956)**	**967**	**(1 989)**
Balance at December 31, 2013	**(3 320)**	**1 152**	**(2 168)**

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. 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, 2012.

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 and entering into option contracts to limit exposure to changes in crude oil prices.

An increase of US$1.00 per barrel of crude oil as at December 31, 2013 would decrease pre-tax earnings for the company's outstanding derivative financial instruments by approximately $2 million.

(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 debt. A 1% strengthening in the Cdn$ relative to the US$ as at December 31, 2013 would decrease pre-tax earnings by approximately $90 million.

The company also has foreign operations whose functional currency is different than the company's functional currency. The main exposures relate to foreign operations whose functional currencies are in U.S. dollars, euros (€) or pound sterling (£). A 1% strengthening in the Cdn$ relative to the US$, € and £ as at December 31, 2013 would decrease Other Comprehensive Income by approximately $43 million, $26 million and $21 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, 2013 was 7.6% of total debt outstanding. The weighted average interest rate on total debt for the year ended December 31, 2013 was 6.3%.

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, 2013, 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, 2013 were $5.2 billion and $6.2 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, 2013		
($ millions)	Trade and other payables	Gross derivative liabilities[1]	Debt[2]
Within one year	**6 911**	**353**	**1 959**
1 to 3 years	**64**	**11**	**1 402**
3 to 5 years	**—**	**—**	**4 064**
Over 5 years	**—**	**—**	**15 746**
	6 975	**364**	**23 171**

(1) Gross derivative liabilities of $364 million are offset by gross derivative assets of $185 million, resulting in a net amount of $179 million.

(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, 2013, substantially all of the company's trade receivables were current.

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, 2013, the company's exposure was $225 million (December 31, 2012 – $53 million).

28. CAPITAL STRUCTURE FINANCIAL POLICIES

The company's primary capital management strategy 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 by reviewing the ratios of 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. This financial covenant under the company's various banking and debt agreements shall not be greater than 65%.

The company's financial covenants are reviewed regularly and controls are in place to maintain compliance with these covenants. The company complied with financial covenants for the years ended December 31, 2013 and 2012.

The company's financial measures, as set out in the following schedule, were unchanged from 2012. The company believes that achieving its 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.

($ millions)	Capital Measure Target	**Dec 31, 2013**	Dec 31, 2012
			(restated – note 6)
Components of ratios			
Short-term debt		**798**	775
Current portion of long-term debt		**457**	311
Long-term debt		**10 203**	9 938
Total debt		**11 458**	11 024
Less: Cash and cash equivalents		**5 202**	4 385
Net debt		**6 256**	6 639
Shareholders' equity		**41 180**	39 215
Total capitalization (total debt plus shareholders' equity)		**52 638**	50 239
Cash flow from operations[1]		**9 412**	9 733
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.

29. JOINT ARRANGEMENTS

Joint Operations

The company's material joint operations as at December 31, 2013 are set out below:

Material Joint Operations	Principal activity	Country of incorporation and principal place of business	Ownership % 2013	Ownership % 2012
Oil Sands				
Operated by Suncor:				
Fort Hills Energy Limited Partnership	Oil sands development	Canada	40.80	40.80
Non-operated:				
Syncrude	Oil sands development	Canada	12.00	12.00
Joslyn	Oil sands development	Canada	36.75	36.75
Exploration and Production				
Operated by Suncor:				
Terra Nova	Oil and gas production	Canada	37.68	37.68
Non-operated:				
White Rose and the White Rose Extensions	Oil and gas production	Canada	26.13-27.50	26.13-27.50
Hibernia and the Hibernia South Extension Unit	Oil and gas production	Canada	19.51-20.00	19.51-20.00
Hebron	Oil and gas production	Canada	22.73	22.73
Harouge Oil Operations	Oil and gas production	Libya	49.00	49.00
Buzzard	Oil and gas production	United Kingdom	29.89	29.89
Golden Eagle Area Development	Oil and gas production	United Kingdom	26.69	26.69

Joint Ventures and Associates

The company does not have any joint ventures or associates that are considered individually material. Summarized aggregate financial information of the joint ventures and associates in the company's refining and marketing operations are shown below:

	Joint ventures		Associates	
($ millions)	**2013**	2012	**2013**	2012
Net earnings	**9**	31	**10**	8
Other comprehensive (loss) income	**(2)**	3	**—**	—
Total comprehensive income	**7**	34	**10**	8
Carrying amount as at December 31	**120**	121	**46**	37

30. SUBSIDIARIES

Material subsidiaries, each of which are wholly owned, either directly or indirectly, by the company as at December 31, 2013, are shown below:

Material Subsidiaries	Principal activity
Canadian Operations	
Suncor Energy Oil Sands Limited Partnership	This partnerships holds most of the company's oil sands and in situ assets.
Suncor Energy Products Inc.	This subsidiary holds interests in the company's energy marketing and renewable energy businesses.
Suncor Energy Products Partnership	This partnership holds substantially all of the company's Canadian refining and marketing assets.
Suncor Energy Marketing Inc.	A subsidiary through which the company's upstream production is marketed, the company's energy trading activities is administered, and the company's refining operations feedstock is procured.
U.S. Operations	
Suncor Energy (U.S.A.) Marketing Inc.	A subsidiary that procures and markets third-party crude oil, in addition to procuring crude oil feedstock for the company's refining operations.
Suncor Energy (U.S.A.) Inc.	A subsidiary through which the company's U.S. refining and marketing operations are conducted.
International Operations	
Suncor Energy UK Limited	A subsidiary through which the majority of the company's North Sea operations are conducted.
Suncor Energy Oil (North Africa) GmbH	A subsidiary through which the majority of the company's Libya operations are conducted.

The table does not include wholly owned subsidiaries that are immediate holding companies of the operating subsidiaries. For certain foreign operations of the company, there are restrictions on the sale or transfer of production licences, which would require approval of the applicable foreign government.

31. RELATED PARTY DISCLOSURES

Related Party Transactions

The company enters into transactions with related parties in the normal course of business, which includes purchases of feedstock, distribution of refined products, and sale of refined products and by-products. These transactions are with joint ventures and associated entities in the company's refining and marketing operations, including pipeline, refined product and petrochemical companies. A summary of the significant related party transactions as at and for the year ended December 31, 2013 and 2012 are as follows:

($ millions)	**2013**	2012
Sales	**1 593**	1 281
Purchases	**245**	157
Accounts receivable	**92**	72
Accounts payable and accrued liabilities	**15**	9

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)	**2013**	2012
Short-term benefits	**14**	18
Pension and other post-retirement benefits	**4**	4
Share-based compensation	**35**	32
	53	54

32. 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:

	Payment due by period						
($ millions)	2014	2015	2016	2017	2018	2019 and beyond	**Total**
Commitments							
Product transportation and storage	660	579	551	526	488	4 015	**6 819**
Energy services	237	183	178	180	182	1 045	**2 005**
Commitments from joint arrangements	3	2	2	1	1	1	**10**
Exploration work commitments	165	363	42	—	—	2	**572**
Other	276	41	9	4	4	25	**359**
Operating leases	545	465	401	341	292	1 903	**3 947**
	1 886	1 633	1 183	1 052	967	6 991	**13 712**

Significant operating leases expire at various dates through 2035. For the year ended December 31, 2013, operating lease expense was $0.6 billion (2012 – $0.5 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. The company has also entered into various pipeline commitments of $6.4 billion with contract terms up to 25 years, which are awaiting regulatory approval. In the event regulatory approval is not obtained, the company has committed to reimbursing certain costs to the service provider.

(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, except as disclosed in note 12.

The company may also have environmental contingent liabilities, beyond decommissioning and restoration liabilities recognized in note 24, which are reviewed individually and are reflected in the company's consolidated 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, 2013, Suncor's insurance program includes coverage of up to US$1.2 billion for oil sands risks, up to US$1.3 billion for offshore risks and up to US$594 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 also carries risk mitigation instruments in the aggregate amount of $300 million on certain foreign operations.

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, 2013, 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 21) 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, 2013, the probability is remote that these guarantee commitments will impact the company.

33. VOYAGEUR UPGRADER PROJECT

Management applies judgment in determining whether an acquisition meets the definition of a business combination or an asset purchase. When a transaction meets the definition of a business combination, the acquired identifiable assets and assumed liabilities, including contingent liabilities, are measured and recognized at their fair value on the date of the acquisition, including tax assets and liabilities. Associated transaction costs are expensed when occurred.

Effective March 27, 2013, the company acquired Total E&P Canada Ltd.'s (Total E&P) interest in Voyageur Upgrader Limited Partnership (VULP) for $515 million and gained full control over the partnership assets. The transaction was accounted for as a business combination.

As VULP was in the development stage and therefore had no revenues and the majority of costs were capitalized, no significant net earnings were generated.

The allocation of the purchase price was based on current best estimates by the company. The completion of the purchase price allocation may result in further adjustment to the carrying value of the recorded assets and liabilities acquired.

The fair value of consideration transferred and the assets acquired and liabilities assumed at the date of acquisition are summarized below:

($ millions)	
Total purchase price	515
Allocation of purchase price:	
Property, plant and equipment	374
Deferred income taxes	312
Decommissioning and restoration provisions	(81)
Contracts and liabilities acquired	(90)
Net assets acquired	515

The fair value attributed to the property, plant and equipment acquired was based on an expected future cash flow approach for assets expected to be retained, with a risk-adjusted discount rate of 10%. For assets expected to be sold, the fair value was determined based on management's best estimate of the recoverable amount.

The fair value of the decommissioning and restoration provisions was determined based on management's best estimate of the costs to complete the reclamation activities, the timing of cash outflows, method of reclamation, the discount rate and management's anticipated use of the area in the future.

Following the acquisition, the company announced that it was not proceeding with the Voyageur upgrader project. The decision was a result of a joint strategic and economic review launched by the company and its co-owner, Total E&P, in response to a change in market conditions that challenged the economics of the project. As a result of not proceeding with the upgrading portion of the project, a charge of $82 million was recorded to net earnings during the year, including costs related to the acceleration of certain reclamation activities.

34. SALE OF NATURAL GAS BUSINESS

On September 26, 2013, the company completed the previously announced sale of a significant portion of its natural gas business in Western Canada for proceeds of $1.0 billion before closing adjustments and other closing costs. The sale of these assets resulted in an after-tax gain on disposal of assets of $130 million in its Exploration and Production segment.

35. SUSPENDED EXPLORATORY WELL COSTS

($ millions)	**2013**	2012
Beginning of year	**318**	387
Additions	**24**	4
Capitalized exploratory well costs charged to expense	**—**	(73)
End of year	**342**	318

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)	**2013**	2012
Suspended exploratory well costs that have been capitalized for a period less than one year	**9**	4
Suspended exploratory well costs that have been capitalized for a period greater than one year	**333**	314
	342	318
Number of suspended exploratory wells that have been capitalized for a period greater than one year	**8**	8

Suspended capitalized costs for exploratory wells completed prior to the end of 2013 are associated with projects located in i) Norway (three wells), ii) Libya (five 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.

36. SUBSEQUENT EVENT

On February 3, 2014, the company's Board of Directors approved a 15% increase to the company's quarterly dividend to $0.23 per common share beginning in the first quarter of 2014. The Board of Directors also approved up to an additional $1.0 billion worth of the company's common shares to be purchased, subject to regulatory approval.

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Audited Consolidated Financial Statements of Suncor Energy Inc. for the fiscal year ended December 31, 2013
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EXHIBIT 99-2

**Management's Discussion and Analysis for the fiscal year ended December 31, 2013,
dated February 28, 2014**

MANAGEMENT'S DISCUSSION AND ANALYSIS

February 24, 2014

This Management's Discussion and Analysis (MD&A) should be read in conjunction with Suncor's December 31, 2013 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 February 28, 2014 (the 2013 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. For a list of abbreviations that may be used in this MD&A, refer to the Advisories – Common Abbreviations section of this MD&A.

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Basis of Presentation

Unless otherwise noted, all financial information has 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.

Effective January 1, 2013, Suncor adopted new and amended accounting standards, described in the Accounting Policies and Critical Accounting Estimates section of this MD&A. Comparative figures presented in this document pertaining to Suncor's 2012 results have been restated while comparative figures pertaining to Suncor's results prior to and including 2011 have not been restated in accordance with the respective transitional provisions of the new and amended standards.

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.

Non-GAAP Financial Measures

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

Measurement Conversions

Crude oil and natural gas liquids volumes have been converted to mcfe or mmcfe on the basis of one bbl to six mcf basis in this MD&A. Also, certain natural gas volumes have been converted to boe or mboe on the same basis. Refer to the Advisories – Measurement Conversions section of this MD&A.

Common Abbreviations

For a list of abbreviations that may be used in this MD&A, refer to the Advisories – Common Abbreviations section of this MD&A.

Risks 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 factors described in the Risk Factors 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 Advisories – Forward-Looking Information section of this MD&A for information on the material risk factors and assumptions underlying our forward-looking information.

1. FINANCIAL AND OPERATING SUMMARY

Financial Summary

Year ended December 31 ($ millions, except per share amounts)	2013	2012	2011
Net earnings	**3 911**	2 740	4 304
per common share – basic	**2.61**	1.77	2.74
per common share – diluted	**2.60**	1.76	2.67
Operating earnings[1]	**4 700**	4 847	5 674
per common share – basic	**3.13**	3.14	3.61
Cash flow from operations[1]	**9 412**	9 733	9 746
per common share – basic	**6.27**	6.30	6.20
Dividends on common shares[2]	**1 095**	756	664
per common share – basic	**0.73**	0.50	0.43
Weighted average number of common shares in millions – basic	**1 501**	1 545	1 571
Weighted average number of common shares in millions – diluted	**1 502**	1 549	1 582
Operating revenues, net of royalties	**39 593**	38 107	38 339
ROCE[1][3] (%)			
For the twelve months ended	**11.5**	7.2	13.8
Capital Expenditures[4]	**6 380**	6 370	6 291
Sustaining	**3 725**	3 252	3 278
Growth	**2 655**	3 118	3 013
Free cash flow[1]	**2 635**	2 776	2 896
Balance Sheet (at December 31)			
Total assets	**78 315**	76 401	74 741
Long-term debt[5]	**10 660**	10 249	10 016
Net debt	**6 256**	6 639	6 976

(1) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures 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) ROCE excludes capitalized costs related to major projects in progress.

(4) Excludes capitalized interest.

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

Operating Summary

Year ended December 31	2013	2012	2011
Production Volumes (mboe/d)			
Oil Sands	**392.5**	359.2	339.3
Exploration and Production	**169.9**	189.9	206.7
Total	**562.4**	549.1	546.0
Average Price Realizations ($/boe)			
Oil Sands	**84.22**	82.75	90.07
Exploration and Production	**91.44**	84.05	79.95
Refinery Utilization[1][2] (%)			
Eastern North America	**91**	89	94
Western North America	**96**	100	91
	94	95	92

(1) Refinery utilization is the amount of crude oil run through crude distillation units, expressed as a percentage of the capacity of these units.

(2) Effective January 1, 2013, the company increased the nameplate capacity of the Edmonton refinery from 135,000 bbls/d to 140,000 bbls/d. 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.

Segment Summary

Year ended December 31 ($ millions)	2013	2012	2011
Net earnings (loss)			
Oil Sands	**2 040**	468	2 603
Exploration and Production	**1 000**	138	306
Refining and Marketing	**2 022**	2 137	1 726
Corporate, Energy Trading and Eliminations	**(1 151)**	(3)	(331)
Total	**3 911**	2 740	4 304
Operating earnings (loss)[1]			
Oil Sands	**2 098**	2 025	2 737
Exploration and Production	**1 210**	850	1 358
Refining and Marketing	**2 022**	2 152	1 726
Corporate, Energy Trading and Eliminations	**(630)**	(180)	(147)
Total	**4 700**	4 847	5 674
Cash flow from (used in) operations[1]			
Oil Sands	**4 556**	4 407	4 572
Exploration and Production	**2 316**	2 227	2 846
Refining and Marketing	**2 618**	3 138	2 574
Corporate, Energy Trading and Eliminations	**(78)**	(39)	(246)
Total	**9 412**	9 733	9 746

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

2. 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; we transport and refine crude oil, and we 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. For a description of Suncor's business segments, refer to the Segment Results and Analysis section of this MD&A.

Suncor's Strategy

We are committed to delivering competitive and sustainable returns to shareholders by focusing on capital discipline, operational excellence and long-term profitable growth, and by leveraging our competitive differentiators; an industry-leading Oil Sands resource base, a proven integrated model, financial strength, industry expertise and a commitment to sustainability. Key components of Suncor's strategy include:

- Profitably operate and develop our resources – Suncor's growth portfolio is focused on projects that are expected to provide long-term profitability for the company. The company's significant resource base and industry expertise at Oil Sands has laid the groundwork for achieving this growth. Suncor's economies of scale have also allowed us to focus on near-term oil sands growth through low-cost debottlenecking and expansion projects.

- Optimize value through integration – From the ground to the gas station, Suncor optimizes its profit through each step of the value chain. As upstream production grows, securing access to global pricing through the company's refining operations and midstream logistics network helps to maximize profit on each upstream barrel.

- Achieve industry leading unit costs in each business segment – Through our focus on operational excellence, we're aiming to get the most out of our operations. Driving down costs and a continued focus on reliability will help to achieve this.

- Industry leader in sustainable development – We're focused on delivering triple bottom line sustainability, which means leadership in environmental performance, social responsibility and creating a strong economy. We are committed to our environmental goals that go beyond compliance in the areas of land reclamation, air emissions, freshwater use and energy efficiency.

2013 Highlights

Suncor reports strong financial results.

- Net earnings for 2013 were $3.911 billion, compared to $2.740 billion in 2012.

- Operating earnings[(1)] for 2013 were $4.700 billion, compared to $4.847 billion in 2012.

- Cash flow from operations[(1)] for 2013 was $9.412 billion, compared to $9.733 billion in 2012.

- ROCE[(1)] (excluding major projects in progress) was 11.5% for the twelve months ended December 31, 2013, compared to 7.2% for the twelve months ended December 31, 2012. ROCE for the twelve months ended December 31, 2013 increased over the same period of 2012 primarily due to an after-tax impairment charge of $1.487 billion relating to the Voyageur upgrader project that reduced ROCE for the twelve months ended December 31, 2012 by approximately 4%.

Return of cash to shareholders increases by over 25%.

Suncor shareholders received approximately $2.8 billion in cash from the company during 2013 through share repurchases and dividends, a 25% increase over the prior year, reinforcing Suncor's commitment to its shareholders.

- The company returned $1.1 billion in dividends, reflecting the 54% increase to Suncor's quarterly dividend announced in early 2013, and $1.7 billion through the repurchase of 49.5 million common shares in 2013, at a weighted average price of $33.84 per share.

- On February 3, 2014, Suncor's Board of Directors approved a 15% increase to its quarterly dividend to $0.23 per common share and authorized additional share repurchases of up to $1 billion.

Suncor's integrated model and relentless focus on capital discipline have delivered consistent cash flows in a volatile price environment

Suncor's well-established operating model and focus on capital discipline as well as long-term profitable growth have resulted in significant free cash flow[(1)].

- Cash flow from operations for 2013 exceeded capital and exploration expenditures by more than $2.6 billion, and was higher than net debt at year end by $3.2 billion.
- The company's solid financial position reaffirmed its ability to deliver reliable and sustainable returns to its shareholders and fund its 2013 capital program with cash flow from operations.

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(1) Operating earnings, cash flow from operations, ROCE and free cash flow are non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

Record Oil Sands production achieved through important milestones and strong operational performance.

In 2013, the Oil Sands business delivered another record-setting year, resulting in an 11% increase in annual production at Oil Sands Operations and record annual SCO production. These results were achieved despite a major turnaround in the second quarter and third-party outages that impacted Oil Sands Operations during the year.

- Strong project execution has allowed the company to nearly triple its production at Firebag in three years. The fourth quarter of 2013 marked the completion of the ramp up at Firebag, with daily production rates reaching approximately 95% of capacity.
- Suncor has facilitated this growth by building strong midstream capabilities while also increasing operational flexibility. The commissioning of the hot bitumen infrastructure in 2013, including the ability to import third-party diluent, has increased the takeaway capacity of bitumen and unlocked production in mining.

Capitalizing on low-cost growth opportunities to steadily increase returns.

- Following a decade of large expansions at Oil Sands Base and Firebag, Oil Sands Operations has the opportunity for production growth through low-cost debottlenecking, expansions and increased reliability.
- The company plans to advance a number of debottlenecking initiatives across Oil Sands Operations and expansions at In Situ, building on the recent success of the hot bitumen infrastructure.
- These initiatives are expected to grow production at existing Oil Sands Operations sites to approximately 500,000 bbls/d by the end of 2018.

Key decisions that are aligned with the company's strategy to focus on long-term profitable growth.

- The sanctioning of the Fort Hills mining project, the sale of the company's conventional natural gas business, and the decision not to proceed with the Voyageur upgrader project have re-positioned Suncor's portfolio, building a strong foundation for long-term profitable growth.
- With a significant reserves and resources base, Suncor continues to assess potential in situ growth prospects at MacKay River, Meadow Creek, Firebag and Lewis.
- In addition to Golden Eagle and Hebron, the company is advancing a number of extension opportunities while expanding its offshore exploration prospects in Norway.

Investing in integration and market access.

As North American commodity prices remain volatile and Suncor's Oil Sands production continues to rise, enhancing access to global markets helps to maximize profitability and operational flexibility.

- Suncor commenced rail shipments of inland crudes to its Montreal refinery in the fourth quarter of 2013, enabling the company to take advantage of the price differentials between inland and Brent crudes.
- In early 2014, Suncor commenced shipments of heavy crude on the Gulf Coast Pipeline, providing the company with more than 50,000 bbls/d of heavy crude shipping capacity to the U.S. Gulf Coast, a profitable outlet for the growing bitumen production at Firebag.
- Suncor's flexible model allows it to take advantage of fluctuating North American crude price differentials. In 2013, discounted crudes were being supplied to the Montreal refinery via rail or ship, while projects were also underway to enable the Montreal refinery to process heavier crude feedstock.

A continued focus on operational excellence and improved reliability.

- Suncor achieved an annual refinery utilization rate of 94% and record upgrading reliability, despite planned maintenance and third-party outages in 2013.
- Demonstrated reliability and continuous improvements at Suncor's refineries resulted in a nameplate capacity increase for the Edmonton refinery for a second year in a row. The company's total refining nameplate capacity of 462,000 bbls/d represents a 4% increase

since 2011.

- Suncor successfully executed planned maintenance across its operations, including a seven-week turnaround at Upgrader 1, a ten-week off-station maintenance program at Terra Nova and planned maintenance at each of its refineries.

3. FINANCIAL INFORMATION

Net Earnings

Suncor's net earnings for 2013 were $3.911 billion, compared to $2.740 billion in 2012. Net earnings were affected by the same factors that influenced operating earnings, which are described in this section of the MD&A. Items affecting net earnings in 2013, compared with 2012, included:

- The after-tax unrealized foreign exchange loss on the revaluation of U.S. dollar denominated debt was $521 million in 2013, compared with a gain of $157 million in 2012.
- In 2013, the company recorded after-tax impairment charges of $563 million in the Exploration and Production segment against its assets in Syria, Libya and North America Onshore. Concurrent with the impairment of its Syrian assets, the company recognized after-tax risk mitigation proceeds of $223 million, previously recorded as a long-term provision.
- In 2013, the company recorded an after-tax charge of $58 million as a result of not proceeding with the Voyageur upgrader project.
- In 2013, the company recorded an after-tax gain of $130 million relating to the sale of the company's conventional natural gas business.
- In 2012, the company recorded an after-tax impairment charge of $1.487 billion against the Voyageur upgrader project.
- In 2012, the company recorded an after-tax impairment (net of reversals) for assets in Syria of $517 million, in addition to after-tax charges of $172 million, including impairments against assets in North America Onshore and East Coast Canada, and a provision in North America Onshore for estimated future commitments relating to 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 charge to net earnings of $88 million.

Operating Earnings

Consolidated Operating Earnings Reconciliation[1]

Year ended December 31 ($ millions)	2013	2012	2011
Net earnings as reported	**3 911**	2 740	4 304
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**521**	(157)	161
Impairments (net of reversals), write-offs, and provisions[2]	**563**	2 176	629
Recognition of risk mitigation proceeds	**(223)**	—	—
Net impact of not proceeding with the Voyageur upgrader project	**58**	—	—
(Gain) loss on significant disposals[3]	**(130)**	—	107
Impact of income tax rate adjustments on deferred income taxes[4]	**—**	88	442
Adjustments to provisions for assets acquired through the merger[5]	**—**	—	31
Operating earnings[1]	**4 700**	4 847	5 674

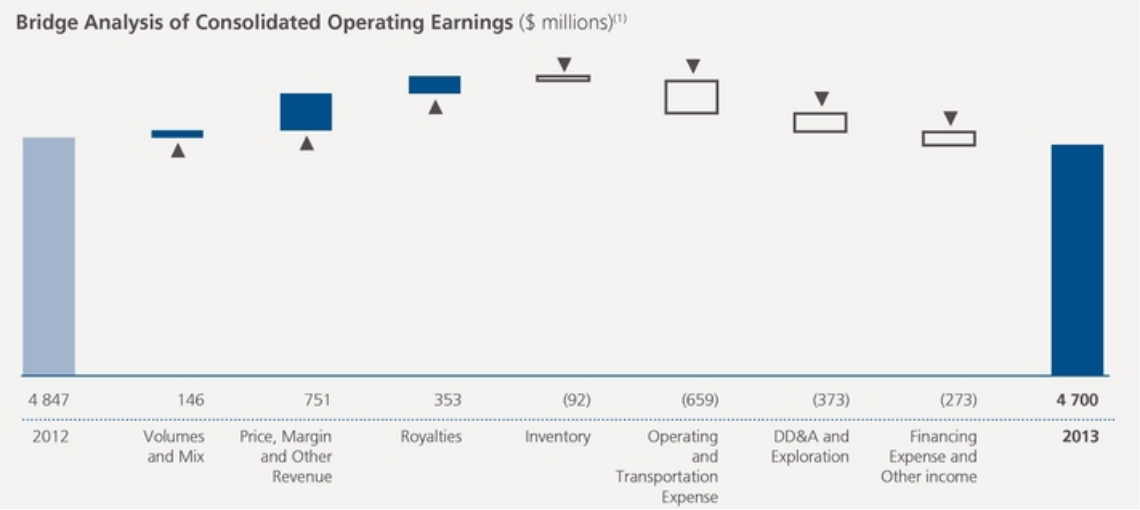
(1) Non-GAAP financial measure. See the Advisories – Non-GAAP Financial Measures section of this MD&A.

(2) In 2011, the company recorded net impairment charges of $503 million ($514 million initial impairment, net of $11 million of subsequent impairment reversals) against assets pertaining to its operations in Libya, which were shut-in as a result of political unrest. The company also recorded $68 million of after-tax impairment charges against certain North America Onshore assets and after-tax write-offs of crude inventories of $58 million.

(3) 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.

(4) In the first quarter of 2011, the U.K. government announced an increase in the tax rate on oil and gas profits in the North Sea that increased the statutory tax rate on Suncor's earnings in the U.K. from 50% to 59.3% in 2011 and to 62% in future years, resulting in an increase to deferred income tax expense of $442 million.

(5) 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.



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

Suncor's consolidated operating earnings for 2013 were $4.700 billion, compared to $4.847 billion in 2012. Factors that positively impacted operating earnings in 2013, compared to 2012, included:

- Average price realizations for production from Oil Sands Operations were higher in 2013 due primarily to strength in WTI and the impact of the weaker Canadian dollar, which more than offset wider light/heavy differentials, that placed downward pressure on prices for sour SCO and bitumen. Exploration and Production price realizations were positively impacted in 2013 by higher natural gas prices and the weaker Canadian dollar. Refining margins were slightly lower in 2013 due to narrower crude differentials and lower crack spreads compared to 2012.

- Total upstream production volumes rose to an average of 562,400 boe/d in 2013, compared to 549,100 boe/d in 2012, reflecting record production in Oil Sands, which more than offset the reduced production from the sale of the company's conventional natural gas business and the shut-in of production in Libya. In Refining and Marketing, strong utilization rates and more favourable feedstock mix and product yield had a positive impact on operating earnings in 2013 compared to 2012.

- Royalties were lower in 2013 compared with 2012, due primarily to the impact of lower production from Libya, partially offset by higher production at Oil Sands.

The following factors had a negative impact on operating earnings in 2013 compared to 2012:

- Operating expenses increased in 2013 primarily due to increased operating costs in Oil Sands, largely associated with increased production, additional mine maintenance, and higher natural gas costs and consumption, as well as increased transportation expense in Oil Sands and Refining and Marketing.

- DD&A and exploration expenses were higher in 2013, due mainly to a larger asset base, partially offset by lower production in Exploration and Production.

- Financing expense and other income increased primarily due to higher interest expense associated with additional capital leases and lower capitalized interest.

Cash Flow from Operations

Consolidated cash flow from operations for 2013 was $9.412 billion, compared to $9.733 billion in 2012. Cash flow from operations decreased due primarily to incremental current income tax expense related to the company's Canadian operations recorded in 2013 and higher operating expenses, partially offset by higher production volumes and higher price realizations.

Results for 2012 compared with 2011

Net earnings for 2012 were $2.740 billion, compared to $4.304 billion in 2011. The decrease in net earnings was due mainly to the same factors impacting operating earnings and by the operating earnings adjustments described above.

Operating earnings for 2012 were $4.847 billion compared to $5.674 billion in 2011. The decrease in operating earnings was due mainly to higher DD&A and exploration expenses, higher operating expenses driven by a larger share-based compensation charge, increased royalty expense due to higher production from Libya, and lower price realizations for upstream production that were largely offset by strong refining margins. Lower production in the Exploration and Production segment was offset by the increase in production from the Oil Sands segment.

Consolidated cash flow from operations for 2012 was $9.733 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.

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	2013	2012	2011
WTI crude oil at Cushing (US$/bbl)	**97.95**	94.20	95.10
Dated Brent crude oil at Sullom Voe (US$/bbl)	**108.75**	111.70	111.15
Dated Brent/Maya FOB price differential (US$/bbl)	**11.65**	12.15	12.50
Canadian 0.3% par crude oil at Edmonton (Cdn$/bbl)	**93.90**	86.60	95.75
WCS at Hardisty (US$/bbl)	**72.75**	73.15	77.95
Light/heavy differential for WTI at Cushing less WCS at Hardisty (US$/bbl)	**25.20**	21.05	17.15
Condensate at Edmonton (US$/bbl)	**101.70**	100.75	105.30
Natural gas (Alberta spot) at AECO (Cdn$/mcf)	**3.15**	2.40	3.65
New York Harbor 3-2-1 crack (1) (US$/bbl)	**23.90**	32.90	27.00
Chicago 3-2-1 crack (1) (US$/bbl)	**21.40**	27.40	24.65
Portland 3-2-1 crack (1) (US$/bbl)	**24.00**	33.40	28.40
Gulf Coast 3-2-1 crack (1) (US$/bbl)	**20.55**	29.00	24.80
Exchange rate (US$/Cdn$)	**0.97**	1.00	1.01
Exchange rate (end of period) (US$/Cdn$)	**0.94**	1.01	0.98

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

Suncor's sweet SCO price realizations are influenced primarily by the price of WTI at Cushing and by the supply and demand of sweet SCO from Western Canada. Price realizations for sweet SCO were positively impacted by an increase in the price for WTI to US$97.95/bbl in 2013, compared to US$94.20/bbl in 2012. Stronger price realizations for sweet SCO also reflected lower industry supplies of SCO volumes due to planned maintenance by large producers in the second and third quarters of 2013, partially offset by strengthening supply, takeaway capacity constraints and lower refinery demand late in 2013.

Suncor produces a specific grade of sour SCO, the price realizations for which are influenced by various crude benchmarks including, but not limited to: Canadian par crude at Edmonton and WCS at Hardisty, and which can also be affected by prices negotiated for spot sales. Prices for Canadian par crude at Edmonton increased while the average for WCS at Hardisty held relatively constant in 2013 compared to 2012, resulting in consistent realizations for sour SCO.

Bitumen production that Suncor does not upgrade is blended with diluent to facilitate delivery on pipeline systems. 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 and SCO). Bitumen price realizations can also be affected by bitumen quality and spot sales. Average prices for WCS at Hardisty held relatively constant in 2013 compared to 2012, resulting in consistent realizations for bitumen.

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 decreased over the prior year and averaged US$108.75/bbl in 2013, compared to US$111.70/bbl in 2012.

Suncor's price realizations for North America Onshore natural gas production are primarily referenced to Alberta spot at AECO. Natural gas is also used in the company's Oil Sands and Refining operations. The average AECO benchmark increased to $3.15/mcf in 2013, from $2.40/mcf in 2012.

Suncor's refining margins are influenced 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. More complex refineries can earn greater margins by processing less expensive, heavier crudes. Crack spreads do not necessarily reflect the margins of a specific refinery. Crack spreads are based on current crude feedstock prices whereas actual refining margins are based on first-in, first-out inventory accounting (FIFO),

where a delay exists between the time that feedstock is purchased and when it is processed and sold to a third party. Specific refinery margins are further impacted by actual crude purchase costs, refinery configuration and refined products sales markets unique to that refinery. In 2013, crack spreads declined significantly, which had an adverse impact on refining margins compared to the prior year.

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.

In 2013, the Canadian dollar weakened in relation to the U.S. dollar as the average exchange rate decreased to 0.97 from 1.00, which had a positive impact on price realizations for the company in 2013.

Conversely, many of Suncor's assets and liabilities, notably most of the company's debt, are denominated in U.S. dollars and translated to Suncor's reporting currency (Canadian dollars) at each balance sheet date. A decrease in the value of the Canadian dollar relative to the U.S. dollar from the previous balance sheet date increases the amount of Canadian dollars required to settle U.S. dollar denominated obligations.

Economic Sensitivities[1][2]

The following table illustrates the estimated effects that changes in certain factors would have had on 2013 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	98	98
Natural gas +Cdn$0.10/mcf	(8)	(8)
Light/heavy differential +US$1.00/bbl	4	4
3-2-1 crack spreads +US$1.00/bbl	113	113
Foreign exchange +$0.01 US$/Cdn$[3]	(52)	(131)
Foreign exchange on U.S. denominated debt +$0.01 US$/Cdn$[3]	79	—

(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) The difference between estimates for net earnings and cash flow from operations are due primarily to the revaluation of U.S. dollar denominated debt that is included within net earnings but not within cash flow from operations.

4. SEGMENT RESULTS AND ANALYSIS

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 either upgrades this production into SCO for refinery feedstock and diesel fuel, or blends the bitumen with diluent for direct sale to market. The Oil Sands segment includes:

- **Oil Sands Operations** refer to Suncor's wholly owned and operated mining, extraction, upgrading, in situ and related logistics and storage 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™) assets.
    - **In Situ** operations include oil sands bitumen production from Firebag and MacKay River and supporting infrastructure, such as central processing facilities, cogeneration units and hot bitumen infrastructure, including an insulated pipeline, diluent import capabilities and a cooling and blending facility, and related storage assets. In Situ production is either upgraded by Oil Sands Base or blended with diluent and marketed directly to customers.
- The Oil Sands segment also includes the company's interests in significant growth projects, including its 40.8% interest in the **Fort Hills** mining project where Suncor is the operator and its 36.8% interest in the **Joslyn** North mining project. The company also holds a 12.0% interest in the **Syncrude** oil sands mining and upgrading operation (these assets were formerly known as Oil Sands Ventures prior to an internal reorganization effective January 1, 2014).

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% 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 projects are located in the U.K. sector of the North Sea and 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. As at February 28, 2014, production in Libya is shut-in due to political unrest. 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 political 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 working interests in unconventional natural gas and crude oil assets in Western Canada, including unconventional oil and natural gas properties in central Alberta and northeast B.C.

REFINING AND MARKETING

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

- **Refining and 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 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 product between the company's segments and the provision of insurance for a portion of the company's operations by the Corporate captive insurance entity.

OIL SANDS

2013 Highlights

- In 2013, the Oil Sands business delivered another record-setting year for production driven by strong project execution and improved reliability, representing an 11% increase in annual production and record annual SCO production at Oil Sands Operations.
- Completion of the Firebag ramp up contributed to a 38% increase in annual production at Firebag over the prior year, reflecting strong project execution and successful project ramp up.
- Suncor is now the largest In Situ producer, with more than 210,000 bbls/d of production capacity from its Firebag and Mackay River operations.
- Installation of the hot bitumen infrastructure enhanced the company's operational flexibility and, coupled with improved reliability, helped to partially mitigate the adverse effects of third-party outages in 2013. These outages reduced annual production by 16,000 bbls/d in 2013.
- Upgrader 1 turnaround was successfully completed in 2013. With no major turnaround event planned until 2016, Oil Sands Operations is well positioned for continued production growth.
- Key decisions in 2013, including the sanctioning of the Fort Hills mining project and the decision not to proceed with the Voyageur upgrader project are aligned with Suncor's strategic objective to focus on projects that will provide long-term profitable growth.

Strategy and Investment Update

Oil Sands Operations has established a large physical asset base providing the opportunity for production growth through low-cost debottlenecks, expansions and increased reliability. In 2013, Suncor focused on advancing these projects and began to realize the benefits of these initiatives through the commissioning of the hot bitumen infrastructure in the third quarter of 2013. The hot bitumen infrastructure has added operational flexibility by enabling the transportation of hot bitumen from Firebag to Suncor's cooling and blending facilities, where the bitumen is blended with either internally produced or imported third-party diluent, and sold directly to market without the need for upgrading. The infrastructure has increased the takeaway capacity of bitumen and unlocked production in mining.

Growth capital for Oil Sands Operations in 2014 is focused on advancing debottlenecking projects and progressing expansions and early stage initiatives. The company anticipates a sanction decision in the second half of 2014 for the MacKay River expansion project, which is targeted to have an initial design capacity of approximately 20,000 bbls/d with first oil expected in 2017. Certain synergies of key processes and utility systems with the existing MacKay River facility are expected. The company also expects to substantially complete the Mackay River facility debottleneck in 2014, which is intended to increase production capacity by approximately 20% for a total capacity of 38,000 bbls/d by the end of 2015. In addition, Suncor plans to focus on validating all other early stage initiatives which involve debottlenecks of logistics infrastructure and Firebag facilities, collectively expected to grow production from existing sites at Oil Sands Operations to approximately 500,000 bbls/d by the end of 2018.

In support of the company's production growth, Suncor continued to expand its storage and logistics network in 2013, including the addition of storage capacity in the Athabasca region and in Hardisty, Alberta.

The company also continues to progress development drilling programs at both Firebag and MacKay River and infill drilling at Firebag, an area of focus in 2014 in support of steady production growth and sustainment.

Oil Sands Operations continues to focus on safe, reliable operations that achieve steady production growth while reducing operating costs. The company's operational excellence initiatives continue to focus on improving facility utilization and workforce productivity. Projects such as the turnaround of Upgrader 1 in the second quarter of 2013 are expected to contribute to further reliability improvements.

Suncor continues to evaluate growth prospects at MacKay River, Meadow Creek, Firebag and Lewis. Furthermore, Suncor's portfolio of technology projects is expected to not only drive improvements and efficiencies in current production, but aid 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, as well as replication

strategies to obtain economies of scale for properties with similar geological characteristics.

Suncor continues to work closely with project co-owners on evaluating and progressing growth projects, including the Fort Hills and Joslyn North mining projects, respectively.

The Fort Hills mining project received sanction in the fourth quarter of 2013. As operator of the project, Suncor plans to develop the mine using traditional open-pit truck and shovel techniques, and solvent-based extraction technology that will allow the mine to produce a final marketable bitumen product. The project is expected to provide Suncor with approximately 73,000 bbls/d of bitumen, with first oil expected in the fourth quarter of 2017. Project activities in 2014 are expected to focus on detailed engineering, procurement and the ramp up of field construction activities.

Earlier in the year, Suncor announced that the company was not proceeding with the Voyageur upgrader project. The decision was a result of a strategic and economic review in response to changes in market conditions that challenged the economics of the project. As part of the decision, Suncor acquired Total E&P Canada Ltd's (Total E&P) interest in the Voyageur Upgrader Limited Partnership (VULP) to gain full control over the partnerships assets, which are used to provide added logistics flexibility and storage capacity for the company's growing Oil Sands Operations.

Suncor and the co-owners of the Joslyn mining project continue to evaluate the project and plan to provide an update on the targeted timing of a sanction decision when available.

Financial Highlights

Year ended December 31 ($ millions)	**2013**	2012	2011
Gross revenues	**13 089**	11 502	12 003
Less: Royalties	**(859)**	(684)	(799)
Operating revenues, net of royalties	**12 230**	10 818	11 204
Net earnings	**2 040**	468	2 603
Operating earnings[(1)]			
Oil Sands Operations	**1 870**	1 807	2 425
Oil Sands Ventures	**228**	218	312
	2 098	2 025	2 737
Cash flow from operations[(1)]	**4 556**	4 407	4 572

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

Oil Sands segment net earnings for 2013 were $2.040 billion, compared to $468 million in 2012. Net earnings in 2013 included a net after-tax charge of $58 million as a result of not proceeding with the Voyageur upgrader project. Net earnings in 2012 included an after-tax impairment charge of $1.487 billion against the Voyageur upgrader project and a deferred tax adjustment of $70 million related to an income tax rate change.

Oil Sands Operations contributed $1.870 billion to operating earnings, while Oil Sands Ventures contributed $228 million. Operating earnings for Oil Sands Operations increased compared to the prior year due primarily to higher production volumes and higher price realizations, partially offset by higher royalty, operating and DD&A expenses. Operating earnings for Oil Sands Ventures increased from 2012, due primarily to higher price realizations, partially offset by lower production volumes and higher DD&A expense.

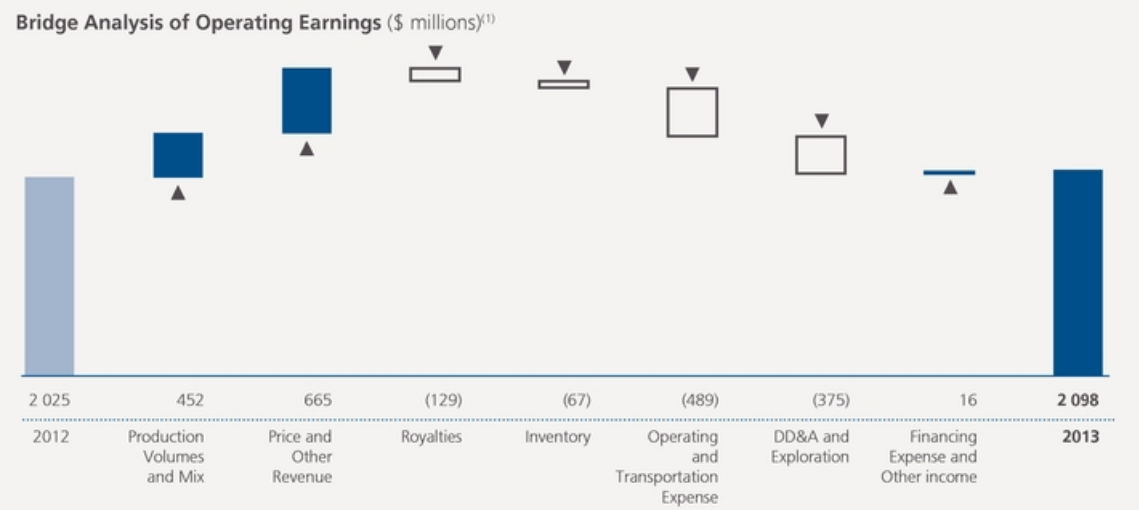
Cash flow from operations for the Oil Sands segment was $4.556 billion in 2013, compared to $4.407 billion in 2012. The increase was primarily due to higher production volumes and higher price realizations, partially offset by higher royalty and operating expenses.

Operating Earnings

Operating Earnings Reconciliation

Year ended December 31 ($ millions)	2013	2012	2011
Net earnings as reported	**2 040**	468	2 603
Net impact of not proceeding with the Voyageur upgrader project	**58**	—	—
Impairments and write-offs	**—**	1 487	35
Impact of income tax rate adjustments on deferred income taxes	**—**	70	—
Loss on significant disposals	**—**	—	99
Operating earnings(1)	**2 098**	2 025	2 737

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



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

Production Volumes(1)

Year ended December 31 (mbbls/d)	2013	2012	2011
Upgraded product (SCO)	**282.6**	276.7	279.7
Non-upgraded bitumen	**77.9**	48.1	25.0
Oil Sands Operations	**360.5**	324.8	304.7
Oil Sands Ventures – Syncrude	**32.0**	34.4	34.6
Total	**392.5**	359.2	339.3

(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 from Suncor's upgrading processes are approximately 79% of bitumen feedstock input.

The Oil Sands segment achieved a third consecutive year of record production with an average of 392,500 bbls/d in 2013, increasing from 359,200 bbls/d in 2012.

The increase in Oil Sands Operations was primarily due to the ramp up of production at Firebag and the hot bitumen assets commissioned in the third quarter of 2013. These assets are comprised of an insulated pipeline from Firebag to Suncor's Athabasca terminal, bitumen cooling and blending facilities, and capacity to import third-party diluents. Record production was achieved despite a number of third-party outages in the year that contributed to lost annual production of 16,000 bbls/d, as well as major maintenance, including a seven-week turnaround of Upgrader 1 in the second quarter of 2013 and planned maintenance of the Upgrader 2 vacuum tower and related units in the third and fourth quarters of 2013.

The increase in bitumen production was complemented by strong upgrading reliability in 2013. Production of upgraded product was the highest on record and averaged

282,600 bbls/d in 2013, compared to 276,700 bbls/d in 2012. Record SCO production was achieved despite planned maintenance and a number of third-party outages.

The third-party outages consisted of a shutdown of a cogeneration facility, which resulted in limited steam availability and required a three-day shutdown of Upgrader 2 in early May and constrained production until early June. Shortly thereafter, a precautionary shutdown of third-party pipelines in response to flooding in northern Alberta required the company to scale back production in the latter part of June and into mid-July. Further, a third-party natural gas outage in the Fort McMurray region in October impacted Suncor's steam generation and upgrading capabilities. Natural gas supply continued to be curtailed intermittently for the remainder of the year, impacting the company's steam generation capabilities. Intermittent curtailments of natural gas supply are expected to continue through the first quarter of 2014 while the third-party operator completes its investigations and restoration activities.

Production of upgraded product 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.

Non-upgraded bitumen production increased to an average of 77,900 bbls/d in 2013, compared to 48,100 bbls/d in 2012, primarily as a result of the ramp up of Firebag and the hot bitumen infrastructure.

Bitumen from Operations

Year ended December 31	**2013**	2012	2011
Oil Sands Base			
Bitumen Production (mbbls/d)	**269.8**	266.2	287.1
Bitumen ore mined (thousands of tonnes per day)	**413.6**	412.3	441.1
Bitumen ore grade quality (bbls/tonne)	**0.65**	0.65	0.65
In Situ bitumen production (mbbls/d)			
Firebag	**143.4**	104.0	59.5
MacKay River	**28.5**	27.0	30.0
Total In Situ production	**171.9**	131.0	89.5
In Situ steam-to-oil ratio			
Firebag	**3.3**	3.4	3.6
MacKay River	**2.6**	2.4	2.2

Bitumen production from Oil Sands Base operations increased to an average of 269,800 bbls/d in 2013, compared to 266,200 bbls/d in 2012, primarily due to strong bitumen production in the latter half of the year. The commissioning of the hot bitumen infrastructure increased the takeaway capacity of bitumen and unlocked production in mining. However, planned maintenance required the company to scale back mine production particularly in the second quarter of 2013 to coincide with limited upgrader availability during the Upgrader 1 turnaround. In 2012, mining activity was also constrained by low upgrader availability and lower ore grade quality of the Millennium mining area.

Bitumen from In Situ operations averaged 171,900 bbls/d in 2013, increasing from 131,000 bbls/d in 2012 due primarily to the ramp up of Firebag production. By the fourth quarter of 2013, production from the Firebag complex had fully ramped up, with daily production rates reaching approximately 95% of capacity during periods that were not impacted by the third-party natural gas outage and curtailment. Production was reduced in the year due to planned maintenance of a central processing facility and a third-party cogeneration outage in the second quarter of 2013. Production from MacKay River averaged 28,500 bbls/d in 2013, compared to 27,000 bbls/d in 2012, and increased primarily due to the commissioning of replacement well pads in 2013 and increased planned maintenance in the prior year, partially offset by the impact of third-party outages in 2013.

Suncor's share of Syncrude production and sales averaged 32,000 bbls/d in 2013, compared to 34,400 bbls/d in 2012. Production in 2013 was impacted by longer than planned shutdowns of one of three cokers, the LC Finer and secondary upgrading units, resulting in the acceleration of planned maintenance for the coker as well as the LC Finer. In addition, unplanned maintenance in upgrading was greater in 2013 compared to 2012.

Sales Volumes and Mix

Year ended December 31	**2013**	2012	2011
Oil Sands sales volumes (mbbls/d)			
Sweet SCO	**91.5**	93.8	85.5

Diesel	**23.5**	24.5	24.3
Sour SCO	**166.0**	161.1	170.6
Upgraded Product (SCO)	**281.0**	279.4	280.4
Non-upgraded bitumen	**76.0**	44.5	24.0
	357.0	323.9	304.4

Sales volumes for Oil Sands Operations increased to 357,000 bbls/d in 2013, compared to 323,900 bbls/d in 2012.

Sales volumes of sweet SCO and diesel decreased slightly compared to 2012. SCO sales mix was impacted by planned maintenance of the Upgrader 1 hydrogen plant and hydrotreating units in the second quarter of 2013 and unplanned maintenance of a diesel hydrotreater in the first quarter of 2013.

Sales volumes of non-upgraded bitumen increased in 2013, compared to 2012, mainly due to higher production at Firebag and the increased takeaway capacity for non-upgraded bitumen.

Inventory

The Inventory variance factor decreased operating earnings primarily due to an increase in the company's average inventory levels in 2013, as a result of new infrastructure added to the company's storage and logistics network to support the growth in production.

Price Realizations

Year ended December 31 Net of transportation costs, but before royalties ($/bbl)	**2013**	2012	2011
Oil Sands			
Sweet SCO and diesel	**104.22**	96.95	103.95
Sour SCO and non-upgraded bitumen	**72.67**	72.93	80.17
Crude sales basket (all products)	**82.83**	81.69	88.74
Crude sales basket, relative to WTI	**(18.09)**	(12.44)	(5.35)
Oil Sands Ventures			
Syncrude – Sweet SCO	**99.82**	92.69	101.80
Syncrude, relative to WTI	**(1.10)**	(1.50)	7.71

Sweet SCO and diesel price realizations for Oil Sands Operations increased to $104.22/bbl in 2013 from $96.95/bbl in 2012, primarily due to an increase in the WTI benchmark and the impact of a weaker Canadian dollar. Sour SCO and bitumen prices increased marginally as the weaker Canadian dollar more than offset the wider WCS to WTI differential. These increases more than offset the impacts of a higher proportion of bitumen sales and resulted in average price realizations for Oil Sands Operations of $82.83/bbl in 2013, compared to $81.69/bbl in 2012.

Suncor's average price realization for Syncrude sales in 2013 was $99.82/bbl, compared to $92.69/bbl in 2012, due to an increase in WTI and the impact of the weaker Canadian dollar in 2013.

Royalties

Royalties were higher in 2013 relative to 2012, primarily due to higher production and slightly higher benchmark prices for WCS that influenced the company's regulated bitumen valuation methodology used to determine royalties. In December 2013, Suncor reached an agreement with the Government of Alberta concerning several outstanding issues under the Royalty Amending Agreements (RAA) entered into in 2008. The impacts of the final settlements were not material to the company's results.

Expenses and Other Factors

Operating expenses for 2013 were higher relative to 2012. Factors contributing to the change in operating expenses included:

- An increase in cash operating costs for Oil Sands Operations. See the Cash Operating Costs Reconciliation for further details.
- Non-production costs were lower in 2013 compared to 2012, due primarily to lower share-based compensation expense and lower costs related to remobilizing certain growth projects.
- Operating expenses at Syncrude were higher for 2013 than 2012, as a result of higher natural gas prices and higher maintenance expenditures.

Transportation expense increased in 2013 relative to 2012 primarily due to increased bitumen production and sales, including incremental costs associated with higher diluent imports.

DD&A expense for 2013 was higher than 2012, due mainly to a larger asset base as a result of assets commissioned in 2013, including Firebag Stage 4 well pads, the hot bitumen infrastructure, the Upgrader 1 turnaround completed in the second quarter of 2013, and other assets commissioned in the latter part of 2012, including Firebag Stage 4 facilities and the Millennium Naptha Unit. The company also derecognized certain assets relating to projects no longer being considered for advancement.

Cash Operating Costs Reconciliation[1][2]

Year ended December 31	**2013**	2012	2011
Operating, selling and general expense (OS&G)	**5 837**	5 365	5 169
Syncrude OS&G	**(536)**	(513)	(529)
Non-production costs[3]	**(267)**	(328)	(275)
Other[4]	**(165)**	(129)	(10)
Oil Sands cash operating costs ($ millions)	**4 869**	4 395	4 355
Oil Sands cash operating costs ($/bbl)	**37.00**	37.05	39.05

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

(2) Effective as of the first quarter of 2012, the calculation of cash operating costs was revised to better reflect the ongoing cash costs of production, and 2011 figures were redetermined accordingly. See the Advisories – Non-GAAP Financial Measures 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 averaged $37.00/bbl, compared to $37.05/bbl in 2012 due to higher production volumes offset by higher total cash operating costs. Total cash operating costs were higher in 2013 due to incremental costs associated with larger operations, including Firebag Stage 4, incremental costs associated with increased production in mining, higher maintenance costs, higher natural gas prices and consumption, partially offset by an increase in the net benefit of power sales due to higher power prices and volumes. The increase in maintenance costs included an acceleration of maintenance programs in 2013 designed to facilitate and ensure reliable and efficient mining operations. The impact on production volumes of the third-party outages resulted in an increase to cash costs per barrel of $1.60/bbl in 2013.

Voyageur Upgrader Project

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.

In the first quarter of 2013, Suncor announced that the company was not proceeding with the Voyageur upgrader project. The decision was a result of a change in market conditions that challenged the economics of the project. Suncor acquired Total E&P's interest in VULP for $515 million to gain full control over the partnership assets, which are currently being used to provide added logistics flexibility and storage capacity for the company's growing Oil Sands operations.

As a result, Suncor recorded an after-tax charge to net earnings of $58 million in 2013 representing the expected costs of not proceeding with the project, including costs related to decommissioning and restoration of the Voyageur site and contract cancellations.

Planned Maintenance

There are no major turnarounds planned for 2014. The company plans to complete routine maintenance on three coker units, in addition to seasonal maintenance throughout 2014. The impact of this maintenance has been reflected in the company's 2014 guidance.

EXPLORATION AND PRODUCTION

2013 Highlights

- The Exploration and Production segment continued to generate significant cash flow for Suncor. Under its current portfolio of assets, the segment is realizing Brent-based pricing for almost all of its production, compared to approximately 70% in 2012.
- In 2013, Suncor completed the sale of the remaining portion of its conventional natural gas business for $1 billion, before closing adjustments and other closing costs, which represented a major milestone in the repositioning of the Exploration and Production portfolio.
- Suncor successfully completed a ten-week off-station maintenance event at Terra Nova, which included preventive maintenance that is expected to contribute to improved reliability in 2014.
- The company's Libyan operations were impacted by political unrest, which limited production and liftings in 2013. Suncor continued to progress its exploration program and continued field activities throughout 2013.
- Operations in Syria remained suspended throughout 2013 as a result of continued political unrest and international sanctions against that country.
- Growth projects progressed well in 2013, including major milestones reached for the Golden Eagle project such as the installation of both jackets and the wellhead topside, as well as the installation of the subsea infrastructure. Following the sanction decision for the Hebron project in 2012, construction of the gravity-based structure and topsides began in 2013.

Strategy and Investment Update

With a suite of high-return development projects, Suncor has earmarked almost half of its total growth capital towards advancing projects within the Exploration and Production segment. Building on the major milestones reached in 2013, growth capital targeted towards the Golden Eagle project is expected to take the project to first oil by late 2014 or early 2015. Drilling operations are expected to commence in early 2014. The Hebron project remains on target for first oil in 2017; detailed engineering and construction of the gravity-based structure and topsides will continue in 2014.

The company has multiple field extension projects underway which leverage existing facilities and infrastructure. Following the completion of subsea installation for the HSEU in 2013, drilling activities began in early 2014. The project is expected to increase overall production and extend the productive life of the Hibernia field starting in 2015. The subsea installation for the South White Rose Extension (SWRX) project commenced in 2013 and first oil is expected in late 2014 or early 2015. A sanction decision for further expansion into the western portion of the White Rose field is targeted for 2014.

The company continues to evaluate offshore exploration prospects in the U.K. North Sea, Norway, and East Coast Canada basins. The company's exploration strategy is primarily concentrated on reviewing and evaluating concentric growth opportunities around existing infrastructure. The company continues to increase its presence in Norway with a current portfolio of 19 licences, where Suncor is operator for eight of these licences. Significant discoveries currently under appraisal include the Beta project where Suncor is the operator and the Butch project where Suncor is a non-operator. Appraisal wells for both projects are planned for 2014.

In 2013, Suncor received extensions on exploration commitments under its EPSAs in Libya to reflect the period that the contracts were suspended due to force majeure. In early 2014, an additional one-year extension to April 2015 was approved by the NOC, with formal extension agreements to follow later in 2014. The terms of the EPSAs allow for further extensions to be negotiated.

Following the disposition of the remaining portion of the company's conventional natural gas business in 2013, properties in the North America Onshore business include high-quality unconventional oil and natural gas properties in central Alberta and northeast B.C.

Financial Highlights

Year ended December 31 ($ millions)	2013	2012	2011
Gross revenues	**6 363**	6 476	6 784
Less: Royalties	**(1 146)**	(1 631)	(1 472)
Operating revenues, net of royalties	**5 217**	4 845	5 312
Net earnings	**1 000**	138	306
Operating earnings[(1)]			
East Coast Canada	**563**	422	694
International	**567**	538	708
North America Onshore	**80**	(110)	(44)
	1 210	850	1 358
Cash flow from operations[(1)]	**2 316**	2 227	2 846

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

Exploration and Production net earnings for 2013 were $1.000 billion, compared to $138 million for 2012. Net earnings for 2013 included after-tax impairment charges of $563 million against assets in Syria, Libya and North America Onshore, partially offset by the recognition of after-tax risk mitigation proceeds of $223 million related to the company's assets in Syria. Net earnings for 2013 were positively impacted by an after-tax gain on sale of $130 million related to the disposition of the company's conventional natural gas business. Net earnings for 2012 included after-tax impairments (net of reversals) of $517 million for assets in Syria, after-tax charges of $172 million, including impairments against assets in North America Onshore and East Coast Canada, and a provision in North America Onshore for estimated future commitments relating to unutilized pipeline capacity.

Operating earnings in 2013 for East Coast Canada were $563 million, compared to $422 million for 2012, and were higher primarily due to larger planned off-station maintenance programs in the prior year. Operating earnings for International were $567 million for 2013, compared to $538 million for 2012, and were higher primarily due to increased production in the U.K., partially offset by lower production volumes in Libya. Operating earnings for North America Onshore were $80 million for 2013, compared with an operating loss of $110 million for 2012, primarily due to the cessation of DD&A on properties that were classified as held for sale since February 2013 and subsequently sold in September 2013, partially offset by lower production volumes.

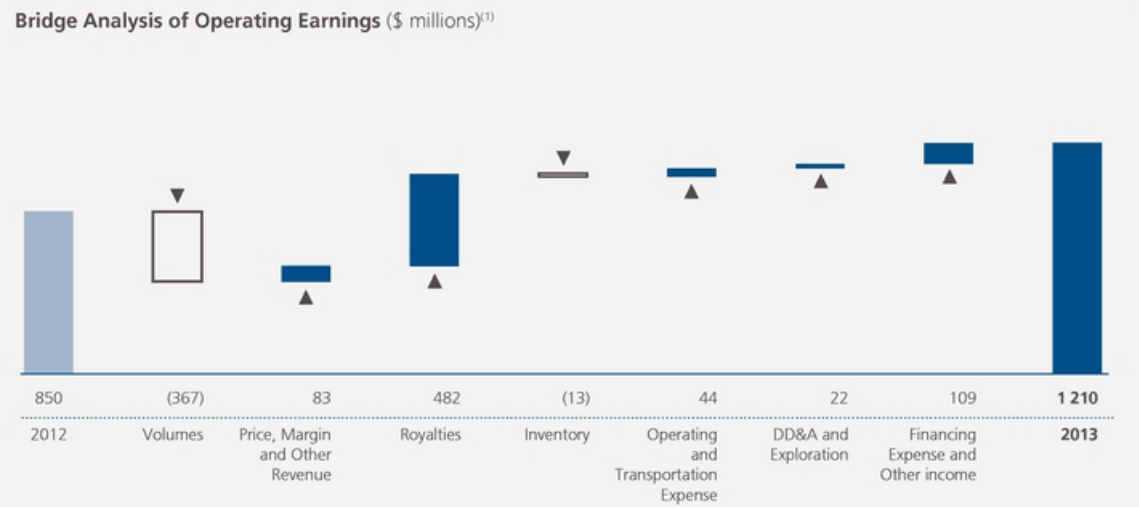
Cash flow from operations was $2.316 billion in 2013, compared to $2.227 billion in 2012, and increased primarily due to higher production volumes at East Coast Canada, partially offset by lower production in Libya and incremental current income tax expense relating to the company's Canadian operations in 2013.

Operating Earnings

Operating Earnings Reconciliation

Year ended December 31 ($ millions)	2013	2012	2011
Net earnings as reported	**1 000**	138	306
Impairments (net of reversals) and provisions	**563**	689	571
Recognition of risk mitigation proceeds	**(223)**	—	—
(Gain) loss on significant disposals	**(130)**	—	8
Impact of income tax rate adjustments on deferred income taxes	**—**	23	442
Adjustments to provisions for assets acquired through the merger	**—**	—	31
Operating earnings[1]	**1 210**	850	1 358

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



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

Production Volumes

Year ended December 31	2013	2012	2011
Production volumes (mboe/d)	**169.9**	189.9	206.7
East Coast Canada (mbbls/d)	**56.2**	46.5	65.6
International (mboe/d)	**76.4**	89.5	76.4
North America Onshore (mmcfe/d)	**224**	323	388
Production Mix (liquids/gas) (%)	**80/20**	74/26	64/36
East Coast Canada	**100/0**	100/0	100/0
International	**98/2**	99/1	82/18
North America Onshore	**14/86**	10/90	8/92

East Coast Canada production averaged 56,200 bbls/d in 2013, compared to 46,500 bbls/d in 2012.

- Production from Terra Nova averaged 14,200 bbls/d in 2013, compared to 8,800 bbls/d in 2012. In 2013, Suncor completed a ten-week off-station maintenance program to repair a mooring chain, perform preventive maintenance on the remaining eight chains and complete routine planned maintenance. In 2012, production was shut-in for 27 weeks for the dockside maintenance program to replace the floating production storage and offloading (FPSO) platform water injection swivel and perform work on subsea infrastructure to help mitigate hydrogen sulphide issues.

- Production from Hibernia averaged 27,100 bbls/d in 2013, compared to 26,100 bbls/d in 2012. Production increased over the prior year due in part to a four-week shut-in for planned maintenance in 2012. Natural declines from older wells were partially offset by production increases from ongoing development drilling.

- Production from White Rose averaged 14,900 bbls/d in 2013, compared to 11,600 bbls/d in 2012. Production increased over the prior year as production in 2012 was shut-in for 15 weeks for an off-station maintenance program to repair the FPSO propulsion system, in addition to other routine planned maintenance activities.

International production averaged 76,400 boe/d in 2013, compared to 89,500 boe/d in 2012.

- Production from Buzzard averaged 55,800 boe/d in 2013, compared to 48,000 boe/d in 2012. Production increased due to higher maintenance activity in 2012, and improved reliability and reservoir performance in 2013.

- Production from Libya averaged 20,600 bbls/d in 2013, compared to 41,500 bbls/d in 2012. Production was shut-in for the latter half of 2013 due to political unrest that resulted in the closure of export terminal operations at eastern Libyan seaports. Production was also impacted by a temporary shut-in at one field throughout the second quarter of 2013 to facilitate the establishment of field security.

North America Onshore production averaged 224 mmcfe/d in 2013, compared to 323 mmcfe/d in 2012, and decreased primarily due to the sale of the conventional natural gas business.

Sale of Natural Gas Business

On April 15, 2013, Suncor announced it had reached an agreement to sell its conventional natural gas business in Western Canada, with an effective date of January 1, 2013. The transaction closed on September 26, 2013 for proceeds of $1 billion, before closing adjustments and other closing costs, resulting in an after-tax gain on sale of $130 million. Suncor's unconventional oil and natural gas properties in central Alberta and northeast B.C. were excluded from the sale.

Price Realizations

Year ended December 31 Net of transportation costs, but before royalties	2013	2012	2011
Exploration and Production ($/boe)	**91.44**	84.05	79.95
East Coast Canada ($/bbl)	**112.39**	112.15	108.42
International ($/boe)	**107.57**	108.22	100.89
North America Onshore ($/mcfe)	**4.74**	3.28	4.39

Average price realizations for crude oil from East Coast Canada and International were consistent with 2012 due to the positive impact of the weaker Canadian dollar being offset by lower benchmark prices for Brent crude.

Average price realizations for North America Onshore were higher due primarily to higher benchmark prices for natural gas and a higher proportion of crude oil and natural gas liquids sales.

Royalties

Royalties were lower in 2013, compared with 2012, due primarily to lower production from Libya and North America Onshore, and lower royalty rates at East Coast Canada due to higher deductible costs related to planned maintenance activities in both 2013 and 2012, partially offset by higher production in East Coast Canada.

Expenses and Other Factors

Operating expenses were lower in 2013 than in 2012 due primarily to lower production volumes in North America Onshore, partially offset by an after-tax expense of $14 million at East Coast Canada associated with the mooring chain repair at Terra Nova, and higher production volumes. The prior year also included an after-tax impact of $14 million, net of insurance proceeds, associated with a fire at an exploratory natural gas well in B.C.

DD&A and exploration expenses were lower in 2013 due to the cessation of DD&A on natural gas properties that were classified as held for sale since February 2013 and subsequently sold in September 2013, partially offset by higher production volumes at East Coast Canada. Exploration expenses were lower in 2013, as the company expensed $82 million in exploration activities ($46 million after-tax) primarily related to wells in the U.K. and Libya, compared to $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 increased in 2013 relative to 2012, primarily due to foreign exchange gains in International and lower accretion on the decommissioning and restoration provision in North America Onshore following the sale of the company's conventional natural gas business.

Impairments and Adjustments to Related Provisions

Syria

Since December 2011, Suncor's operations in Syria and its contractual obligations have been suspended under a period of force majeure due to political unrest and international sanctions. As there has been no resolution of the political situation and rising uncertainty with respect to the company's return to operations in the country, Suncor impaired the remaining carrying value of its Syrian's assets resulting in an after-tax impairment charge of $422 million in the fourth quarter of 2013. The carrying value had previously been impaired in the second quarter of 2012 and a portion subsequently reversed in the fourth quarter of 2012, for after-tax impairments (net of reversals) of $517 million in 2012.

The company received risk mitigation proceeds in the fourth quarter of 2012, at which time the proceeds were recorded as a non-current provision to reflect potential repayment if operations in Syria were to resume. Suncor recognized the risk mitigation proceeds of $300 million ($223 million after-tax) in net earnings in the fourth quarter of 2013, as the likelihood of return in the foreseeable future is undeterminable.

Libya

Recent political unrest resulted in the closure of export terminal operations at eastern Libyan seaports, requiring the shut-in of production for the latter half of 2013. As the situation persisted at the end of 2013, an impairment test was performed based on an assessment of future net cash flows over a range of possible outcomes. Based on this assessment, the company recorded an after-tax impairment charge of $101 million in the fourth quarter of 2013.

The carrying value of the company's net assets in Libya as at December 31, 2013 was approximately $570 million.

Other

During the fourth quarter of 2013, the company recognized an after-tax impairment charge of $40 million relating to its properties in North America Onshore based on an assessment of future net cash flows incorporating recent drilling activity, updated reserves data, cost assumptions and price forecasts.

In 2012, the company recorded after-tax impairment charges of $172 million, including impairments against assets in North America Onshore and East Coast Canada, and a provision in North America Onshore for estimated future commitments relating to unutilized pipeline capacity.

Planned Maintenance

Routine annual planned maintenance has been scheduled for Terra Nova and White Rose in the third quarter of 2014, and for Buzzard in the second and third quarters of 2014. The impact of this maintenance has been reflected in the company's 2014 guidance.

REFINING AND MARKETING

2013 Highlights

- The refining and marketing segment continued to deliver value by generating more than $2 billion in operating earnings for the second consecutive year, through integration and strong reliability in 2013.
- With 460,000 bbls/d of crude processing capacity in 2013, the refining operations sheltered the company from the volatility in crude differentials by optimizing the profit realized on the majority of Suncor's upstream production.
- Building on the nameplate capacity increases at the Edmonton, Sarnia and Commerce City refineries in 2012 and 2013, the company again increased the nameplate capacity of the Edmonton refinery as a result of continuous reliability improvements to 142,000 bbls/d as at January 1, 2014.
- Overall refinery utilization reached 94%, while planned maintenance activities were completed at each refinery in 2013.
- Suncor continued to maximize value by sourcing approximately 70% of its refining feedstock from inland crude sources, compared to higher cost coastal crudes.
- The company completed a rail offloading facility located adjacent to the Montreal refinery and entered into firm commitments for rail cars and terminalling services to increase inland crude supply to the Montreal refinery.

Strategy and Investment Update

Suncor continues to invest in profitable growth and optimize overall integration, including market access initiatives to supply the Montreal refinery with discounted North American crudes. Rail transportation to Quebec commenced in the fourth quarter of 2013 and is expected to increase to approximately 35,000 bbls/d of inland crude by the first quarter of 2014. Suncor has also started a project to modify the hydrocracking unit at the Montreal refinery, which is expected to improve energy efficiency and product yield, by 2015, and contribute to the company's integration strategies. Suncor continues to evaluate further investment opportunities to increase the heavy crude processing capability at the Montreal refinery, in addition to actively monitoring the regulatory process for future pipeline access.

Suncor's Petro-Canada branded outlets continue to be a leading retailer by market share in major urban areas of Canada. Increased competition and softening 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, including global expansion in the U.S., Europe and China.

Financial Highlights

Year ended December 31 ($ millions)	2013	2012	2011
Operating revenues	**26 658**	26 220	25 713
Net earnings	**2 022**	2 137	1 726
Operating earnings[1]			
Refining and Product Supply	**1 758**	1 877	1 413
Marketing	**264**	275	313
	2 022	2 152	1 726
Cash flow from operations[1]	**2 618**	3 138	2 574

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

Refining and Marketing recorded net and operating earnings of $2.022 billion in 2013, compared to net earnings of $2.137 billion and operating earnings of $2.152 billion in 2012.

Refining and Supply operations contributed $1.758 billion to operating earnings in 2013, a decrease compared with 2012, primarily due to lower crack spreads, higher operating expenses and higher DD&A, partially offset by the impact of FIFO inventory accounting relative to an estimated LIFO basis of accounting, which had a positive impact to net earnings of approximately $79 million after-tax, compared to a negative impact of approximately $153 million after-tax in 2012. Marketing operations contributed $264 million to operating earnings in 2013, compared to $275 million in 2012, primarily due to higher operating expenses, partially offset by higher margins for lubricants and the retail channel.

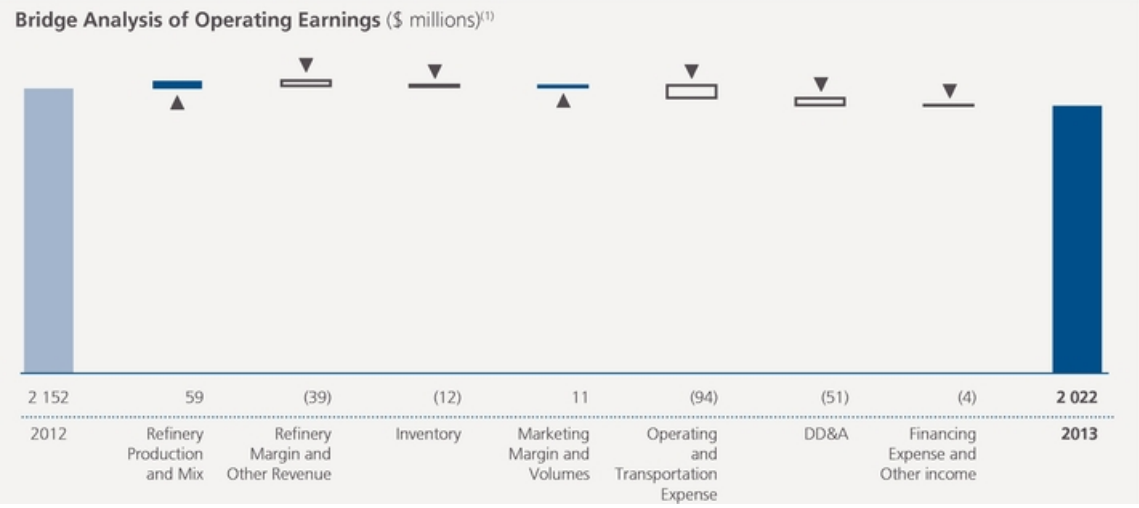
Cash flow from operations was $2.618 billion in 2013, compared to $3.138 billion in 2012, and decreased primarily due to incremental current income tax expense relating to the company's Canadian operations recorded in 2013, in addition to the majority of the factors that impacted operating earnings.

Operating Earnings

Operating Earnings Reconciliation

Year ended December 31 ($ millions)	**2013**	2012	2011
Net earnings as reported	**2 022**	2 137	1 726
Impact of income tax rate adjustments on deferred income taxes	**—**	15	—
Operating earnings[1]	**2 022**	2 152	1 726

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



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

Volumes

Year ended December 31	2013	2012	2011
Crude oil processed (mbbls/d)			
Eastern North America	**201.7**	197.7	201.3
Western North America	**229.6**	233.7	206.4
Total	**431.3**	431.4	407.7
Refinery utilization[(1)(2)] (%)			
Eastern North America	**91**	89	94
Western North America	**96**	100	91
Total	**94**	95	92
Refined Product Sales (mbbls/d)			
Gasoline	**247.4**	252.8	249.5
Distillate	**209.8**	195.0	190.7
Other	**85.7**	90.7	82.5
	542.9	538.5	522.7

(1) Effective January 1, 2013, the company increased the nameplate capacity of the Edmonton refinery from 135,000 bbls/d to 140,000 bbls/d. 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.

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

Refinery utilization in Eastern North America averaged 91% in 2013, compared to 89% in 2012. Refinery utilization increased over the prior year due to significantly less unplanned maintenance in 2013, partially offset by planned maintenance at the Sarnia and Montreal refineries. Refinery utilization in 2012 was impacted by an unplanned outage of a crude unit at the Sarnia refinery, 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.

Refinery utilization in Western North America averaged 96% in 2013, compared to 100% in 2012. The decrease from the prior year is primarily due to more maintenance activities occurring in 2013, including a four-week planned maintenance event at the Edmonton refinery of the heavy sour crude train and unplanned maintenance in the second and fourth quarters of 2013, partially offset by higher utilization at the Commerce City refinery due to stronger overall reliability in 2013. Despite this unplanned maintenance, overall demonstrated reliability improvements resulted in an increase to the nameplate capacity of the Edmonton refinery to 142,000 bbls/d from 140,000 bbls/d effective January 1, 2014.

Total sales of refined petroleum products increased to an average of 542,900 bbls/d in 2013, compared to 538,500 bbls/d in 2012. Distillate sales increased from the prior year due to higher production and increasing diesel sales through Suncor's retail and supply sales channels. Gasoline sales decreased from the prior year due to economic conditions and competitive pressures primarily in Eastern North America.

Prices and Margins

For Refining and Product Supply, prices and margins for refined products were lower in 2013 compared to 2012.

- The narrowing differential between Brent and WTI throughout 2013 relative to the prior year contributed to a decline in benchmark crack spreads across all regions in which the company sells refined products compared to the prior year.
- Average inland crude differentials to WTI were relatively consistent year-over-year for SCO. However, the wider light/heavy crude oil differential positively impacted earnings for the inland refineries.
- In 2013, the impact of FIFO inventory accounting, as used by the company, relative to an estimated LIFO basis of accounting had a positive impact to net earnings of approximately $79 million after-tax, compared to a negative impact of approximately $153 million after-tax in 2012.

Marketing margins increased primarily due to higher margins for lubricants and the retail channels.

Expenses and Other Factors

Operating expenses were higher in 2013 than in 2012, due to higher energy costs and consumption, higher transportation costs associated with increased asphalt volumes and overall delivery rates, and higher repairs and maintenance expense, partially offset by lower share-based compensation expense.

Planned Maintenance

The company has scheduled a planned maintenance event at the Commerce City refinery in the first quarter of 2014 with an expected duration of three weeks. The Montreal refinery has a five-week planned maintenance event in the second quarter of 2014 as well as an eight-week planned maintenance event beginning late in the third quarter of 2014. The Edmonton refinery has a seven-week planned maintenance event in the second quarter of 2014 as well as a four-week planned maintenance event in the third quarter of 2014.

The impact of this maintenance has been reflected in the company's 2014 guidance.

CORPORATE, ENERGY TRADING AND ELIMINATIONS

2013 Highlights

- The Energy Trading business continued to expand Suncor's logistics network by securing market access into Canadian and U.S. Coastal markets, positioning the company to capture global prices on both its current production and future growth.
- In addition to the rail projects supporting the Refining and Marketing segment, the company increased its heavy crude capacity to the U.S. Gulf Coast through the Gulf Coast Pipeline, which began shipments in early 2014. Suncor also has positions on a number of major proposed pipeline projects, subject to various approvals and conditions.
- The company continued to progress the Adelaide and Cedar Point wind projects. The Adelaide project received regulatory approval in December 2013.

Strategy and Investment Update

The Energy Trading business supports the company's production by securing market access, 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 company expects to complete the Adelaide wind project by the fourth quarter of 2014. The Cedar Point project continues to progress through the regulatory process. The two projects, based in Ontario, 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)	**2013**	2012	2011
Net loss	**(1 151)**	(3)	(331)
Operating (loss) earnings[1]			
Renewable Energy	**72**	57	72
Energy Trading	**116**	147	149
Corporate	**(785)**	(468)	(346)
Group Eliminations	**(33)**	84	(22)
	(630)	(180)	(147)
Cash flow used in operations[1]	**(78)**	(39)	(246)

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

Net loss for Corporate, Energy Trading and Eliminations for 2013 was $1.151 billion, compared to a net loss of $3 million for 2012. In 2013, 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 debt of $521 million. In 2012, the Canadian dollar strengthened in relation to the U.S. dollar, resulting in an after-tax unrealized foreign exchange gain on U.S. dollar denominated debt of $157 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 2013 was $630 million, compared with an operating loss of $180 million in 2012. Operating earnings are discussed below.

Operating Earnings

Operating Earnings Reconciliation

Year ended December 31 ($ millions)	2013	2012	2011
Net loss as reported	**(1 151)**	(3)	(331)
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**521**	(157)	161
Impact of income tax rate adjustments on deferred income taxes	**—**	(20)	—
Impairments and write-offs	**—**	—	23
Operating loss[1]	**(630)**	(180)	(147)

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

Renewable Energy

Year ended December 31	2013	2012	2011
Power generation marketed (gigawatt hours)	**430**	429	245
Ethanol production (thousands of m^3)	**415**	413	382

Suncor's renewable energy assets contributed operating earnings of $72 million in 2013, compared to $57 million in 2012, and increased primarily due to stronger margins on ethanol sales driven by lower feedstock prices, and higher average power prices in 2013.

Energy Trading

Energy Trading activities contributed operating earnings of $116 million in 2013, compared to $147 million in 2012. Energy trading continued to contribute to operating earnings, primarily through its heavy crude trading strategies, which were adversely impacted by fluctuating crude differentials in the latter half of 2013.

Corporate

Corporate had an operating loss of $785 million in 2013, compared with an operating loss of $468 million in 2012. The increase in operating loss was due primarily to higher interest expense due to lower capitalized interest and increased financing expense associated with additional capital leases, higher share-based compensation expense and incremental expenditures relating to a company-wide process improvement initiative. The company capitalized $397 million of its borrowing costs in 2013 as part of the cost of major projects, compared to $587 million in the prior year, reflecting fewer major projects in 2013.

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 sells the products produced from intersegment purchases of crude feedstock to third parties. In 2013, $33 million of after-tax intersegment profit was eliminated, compared to $84 million after-tax of previously eliminated intersegment profit that was recognized in 2012.

5. FOURTH QUARTER 2013 ANALYSIS

Financial and Operational Highlights

Three months ended December 31 ($ millions, except as noted)	2013	2012
Net earnings (loss)		
Oil Sands	**469**	(1 037)
Exploration and Production	**(101)**	148
Refining and Marketing	**458**	450
Corporate, Energy Trading and Eliminations	**(383)**	(135)
Total	**443**	(574)
Operating earnings (loss)[1]		
Oil Sands	**400**	450
Exploration and Production	**239**	143
Refining and Marketing	**458**	450
Corporate, Energy Trading and Eliminations	**(124)**	(55)
Total	**973**	988
Cash flow from (used in) operations[1]		
Oil Sands	**1 110**	1 090
Exploration and Production	**552**	529
Refining and Marketing	**534**	634
Corporate, Energy Trading and Eliminations	**154**	(25)
Total	**2 350**	2 228
Production volumes (mboe/d)		
Oil Sands	**446.5**	378.7
Exploration and Production	**111.6**	177.8
Total	**558.1**	556.5

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

Segment Analysis

Oil Sands

For the fourth quarter of 2013, Oil Sands segment net earnings were $469 million, compared with a net loss of $1.037 billion for the fourth quarter of 2012. Net earnings in the quarter included a favourable after-tax adjustment of $69 million relating to not proceeding with the Voyageur upgrader project to reduce the previous cost estimate recorded in the first quarter of 2013. Due to acceleration of project closure activities and a redeployment of resources, the company has reduced the costs associated with not proceeding with the project. The net loss in the fourth quarter of 2012 included an after-tax impairment charge of $1.487 billion against the Voyageur upgrader project.

Operating earnings for the fourth quarter of 2013 were $400 million, compared to $450 million in the prior year quarter. Despite record production volumes, operating earnings for Oil Sands Operations decreased due to higher operating, royalty and DD&A expenses, and lower average price realizations.

Cash operating costs per barrel for Oil Sands Operations in the fourth quarter of 2013 averaged $36.85/bbl compared to $38.00/bbl in the fourth quarter of 2012, reflecting higher production volumes, partially offset by higher total cash operating costs. Total cash operating costs were higher partially due to the acceleration of maintenance programs designed to facilitate and ensure reliable and efficient mining operations. Total cash operating costs also increased relative to the prior year quarter due to incremental costs associated with larger operations, including Firebag

Stage 4, incremental costs associated with increased production in mining, higher natural gas prices and consumption, and a decrease in the net benefit of power sales due to lower power prices.

Cash flow from operations for the Oil Sands segment in the fourth quarter of 2013 was $1.110 billion, compared to $1.090 billion in the fourth quarter of 2012, and increased due to higher production volumes, which was partially offset by higher operating and royalty expenses.

Oil Sands Operations continued to set quarterly records in the fourth quarter of 2013, with average production volumes of 409,600 bbls/d, compared to 342,800 bbls/d in the prior year quarter. The increase was primarily due to the ramp up of production at Firebag and the hot bitumen infrastructure commissioned in the third quarter of 2013. Production was reduced throughout the quarter due to a third-party natural gas outage and subsequent curtailments that impacted the Fort McMurray region and resulted in approximately 15,000 bbls/d of lost production in the fourth quarter of 2013. Suncor's share of Syncrude production averaged 36,900 bbls/d in the fourth quarter of 2013, consistent with production of 35,900 bbls/d in the fourth quarter of 2012.

Exploration and Production

The net loss in Exploration and Production was $101 million for the fourth quarter of 2013, compared with net earnings of $148 million for the fourth quarter of 2012. The net loss for the fourth quarter of 2013 includes

after-tax impairment charges of $563 million against assets in Syria, Libya and North America Onshore, partially offset by the recognition of after-tax risk mitigation proceeds of $223 million related to the company's assets in Syria. Net earnings for the fourth quarter of 2012 included a net after-tax recovery of $177 million related to an impairment reversal for assets in Syria, which was almost fully offset by after-tax charges of $172 million including impairments against assets in North America Onshore and East Coast Canada, and a provision in North America Onshore for estimated future commitments relating to unutilized pipeline capacity.

Exploration and Production operating earnings were $239 million in the fourth quarter of 2013, compared to $143 million in the fourth quarter of 2012. Operating earnings increased primarily due to higher price realizations and lower royalty expenses, partially offset by lower production volumes due to the sale of the conventional natural gas business and the shut-in of Libya production.

Cash flow from operations was $552 million for the fourth quarter of 2013, compared to $529 million for the fourth quarter of 2012, and increased due to the same factors that impacted operating earnings, partially offset by incremental current income tax expense relating to the company's Canadian operations recorded in the fourth quarter of 2013.

Production volumes were 111.6 mboe/d in the fourth quarter of 2013, compared to 177.8 mboe/d in the fourth quarter of 2012. The decrease in production volumes was due mainly to the sale of the conventional natural gas business, the shut-in of production in Libya and planned maintenance programs, partially offset by increased production at Buzzard due to strong reliability and reservoir performance in the fourth quarter of 2013 and more planned maintenance activity in the prior year quarter.

Refining and Marketing

For the fourth quarter of 2013, Refining and Marketing net and operating earnings were $458 million, compared to net and operating earnings of $450 million for the fourth quarter of 2012. The increase was due to significantly wider inland crude differentials that were partially offset by lower benchmark crack spreads resulting from the narrowing of the WTI to Brent differential and lower throughput volumes.

Refining and Marketing cash flow from operations was $534 million in the fourth quarter of 2013, compared to $634 million in the fourth quarter of 2012, and decreased primarily due to incremental current income tax expense related to the company's Canadian operations recorded in the quarter.

Overall refinery utilization decreased to 91% in the fourth quarter of 2013, compared to 96% in the fourth quarter of 2012, due to planned maintenance at both the Sarnia and Montreal refineries and unplanned maintenance at the Edmonton refinery in the fourth quarter of 2013. However, the impact of lower throughput was partially offset by more favourable product mix, as mix in the prior year quarter was adversely impacted by unplanned maintenance at the Sarnia refinery.

Corporate, Energy Trading and Eliminations

The net loss for Corporate, Energy Trading and Eliminations in the fourth quarter of 2013 was $383 million, compared to a net loss of $135 million in the fourth quarter of 2012. In the fourth quarter of 2013, 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 debt of $259 million, compared to $80 million in the prior year quarter.

Operating loss for Corporate, Energy Trading and Eliminations in the fourth quarter of 2013 was $124 million, compared to a $55 million loss in the fourth quarter of 2012. The increase in operating loss was due primarily to losses on the company's crude trading strategies in the fourth quarter of 2013, compared to gains in the prior year quarter, higher share-based compensation expense in the quarter, higher financing expense associated with additional capital leases and lower capitalized interest, and incremental expenditures relating to a company-wide process improvement initiative.

Corporate, Energy Trading and Eliminations cash flow from operations increased to $154 million in the fourth quarter of 2013, compared to cash flow used in operations of $25 million in the fourth quarter of 2012, due primarily to realized gains on trading strategies in Energy Trading and incremental current income tax recoveries related to the company's Canadian operations recorded in the quarter.

Operating Earnings[1]

Three months ended December 31	Oil Sands		Exploration and Production		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012
Net earnings (loss) as reported	**469**	(1 037)	**(101)**	148	**458**	450	**(383)**	(135)	**443**	(574)
Unrealized foreign exchange loss on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**259**	80	**259**	80
Net impact of not proceeding with the Voyageur upgrader project	**(69)**	—	**—**	—	**—**	—	**—**	—	**(69)**	—
Impairments (net of reversals), write-offs and provisions	**—**	1 487	**563**	(5)	**—**	—	**—**	—	**563**	1 482
Recognition of risk mitigation proceeds	**—**	—	**(223)**	—	**—**	—	**—**	—	**(223)**	—
Operating earnings (loss)	**400**	450	**239**	143	**458**	450	**(124)**	(55)	**973**	988

Cash Flow from Operations [1]

Three months ended December 31	Oil Sands		Exploration and Production		Refining and Marketing		Corporate, Energy Trading and Eliminations		Total	
($ millions)	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012
Net earnings (loss)	**469**	(1 037)	**(101)**	148	**458**	450	**(383)**	(135)	**443**	(574)
Adjustments for:										
Depreciation, depletion, amortization and impairment	**680**	2 552	**915**	300	**149**	127	**31**	35	**1 775**	3 014
Deferred income taxes	**35**	(357)	**—**	2	**(84)**	68	**41**	(39)	**(8)**	(326)
Accretion of liabilities	**30**	26	**10**	15	**2**	1	**2**	3	**44**	45
Unrealized foreign exchange loss on U.S. dollar denominated debt	**—**	—	**—**	—	**—**	—	**304**	91	**304**	91
Change in fair value of derivative contracts	**1**	—	**1**	1	**2**	(1)	**154**	(20)	**158**	(20)
Gain on disposal of assets	**—**	—	**—**	—	**(3)**	(5)	**—**	—	**(3)**	(5)
Share-based compensation	**17**	17	**7**	3	**10**	10	**47**	13	**81**	43
Exploration expenses	**—**	—	**23**	21	**—**	—	**—**	—	**23**	21
Settlement of decommissioning and restoration liabilities	**(75)**	(70)	**1**	(10)	**(7)**	(8)	**—**	—	**(81)**	(88)
Other	**(47)**	(41)	**(304)**	49	**7**	(8)	**(42)**	27	**(386)**	27
Cash flow from (used in) operations	**1 110**	1 090	**552**	529	**534**	634	**154**	(25)	**2 350**	2 228
(Increase) decrease in non-cash working capital	**(963)**	35	**91**	(117)	**340**	(489)	**518**	(481)	**(14)**	(1 052)
Cash flow provided by (used in) operating activities	**147**	1 125	**643**	412	**874**	145	**672**	(506)	**2 336**	1 176

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

6. QUARTERLY FINANCIAL DATA

Financial Summary

Three months ended ($ millions, unless otherwise noted)	**Dec 31 2013**	Sept 30 2013	June 30 2013	Mar 31 2013	Dec 31 2012	Sept 30 2012	June 30 2012	Mar 31 2012
Total production (mboe/d)								
Oil Sands	**446.5**	423.6	309.4	389.0	378.7	378.9	337.8	341.1
Exploration and Production	**111.6**	171.4	190.7	207.1	177.8	156.4	204.6	221.2
	558.1	595.0	500.1	596.1	556.5	535.3	542.4	562.3
Revenues and other income								
Operating revenues, net of royalties	**9 814**	10 288	9 648	9 843	9 396	9 488	9 584	9 639
Other income	**380**	85	66	173	92	88	123	116
	10 194	10 373	9 714	10 016	9 488	9 576	9 707	9 755
Net earnings (loss)	**443**	1 694	680	1 094	(574)	1 544	324	1 446
per common share – basic (dollars)	**0.30**	1.13	0.45	0.72	(0.38)	1.01	0.21	0.93
per common share – diluted (dollars)	**0.30**	1.13	0.45	0.71	(0.38)	1.00	0.20	0.92
Operating earnings[(1)]	**973**	1 426	934	1 367	988	1 292	1 249	1 318
per common share – basic[(1)] (dollars)	**0.66**	0.95	0.62	0.90	0.65	0.84	0.80	0.84
Cash flow from operations[(1)]	**2 350**	2 528	2 250	2 284	2 228	2 743	2 347	2 415
per common share – basic[(1)] (dollars)	**1.58**	1.69	1.49	1.50	1.46	1.79	1.51	1.55
ROCE[(1)] (%) for the twelve months ended	**11.5**	8.6	8.1	7.1	7.2	12.4	14.2	14.7
Common share information (dollars)								
Dividend per common share	**0.20**	0.20	0.20	0.13	0.13	0.13	0.13	0.11
Share price at the end of trading								
Toronto Stock Exchange (Cdn$)	**37.24**	36.83	31.00	30.44	32.71	32.34	29.44	32.59
New York Stock Exchange (US$)	**35.05**	35.78	29.49	30.01	32.98	32.85	28.95	32.70

(1) Non-GAAP financial measures. See the Advisories – Non-GAAP Financial Measures section of this document. ROCE excludes capitalized costs related to major projects in progress. Operating earnings for each quarter of 2013 and 2012 is defined in the Non-GAAP Financial Measures Advisory section and reconciled to GAAP measures in the Consolidated Financial Information and Segment Results and Analysis sections of each respective quarterly Report to Shareholders issued in respect of the relevant quarter for 2013 (Quarterly Reports). Cash flow from operations and ROCE are defined and reconciled to GAAP measures in the Advisories – Non-GAAP Financial Measures section of each respective Quarterly Report.

Business Environment

Three months ended (average for the period ended, except as noted)		**Dec 31 2013**	Sept 30 2013	June 30 2013	Mar 31 2013	Dec 31 2012	Sept 30 2012	June 30 2012	Mar 31 2012
WTI crude oil at Cushing	US$/bbl	**97.45**	105.85	94.20	94.35	88.20	92.20	93.50	102.95
Dated Brent crude oil at Sullom Voe	US$/bbl	**109.35**	109.70	103.35	112.65	110.10	109.50	108.90	118.35
Dated Brent/Maya FOB price differential	US$/bbl	**20.05**	10.35	5.50	10.60	17.30	11.90	9.85	9.45
Canadian 0.3% par crude oil at Edmonton	Cdn$/bbl	**89.05**	105.25	92.90	88.45	84.35	84.70	84.45	92.80
WCS at Hardisty	US$/bbl	**65.25**	88.35	75.05	62.40	70.05	70.45	70.60	81.50
Light/heavy crude oil differential for WTI at Cushing less WCS at Hardisty	US$/bbl	**32.20**	17.50	19.15	31.95	18.15	21.75	22.90	21.45
Condensate at Edmonton	US$/bbl	**94.20**	103.80	103.30	107.20	98.10	96.00	99.40	110.00
Natural gas (Alberta spot) at AECO	Cdn$/mcf	**3.15**	2.80	3.60	3.05	3.05	2.20	1.85	2.50
New York Harbor 3-2-1 crack (1)	US$/bbl	**19.60**	19.25	25.60	31.20	35.95	37.80	31.95	25.80
Chicago 3-2-1 crack (1)	US$/bbl	**12.00**	15.80	30.70	27.10	27.85	35.15	27.85	18.80
Portland 3-2-1 crack (1)	US$/bbl	**15.35**	19.60	30.60	30.55	29.85	38.15	37.90	27.70
Gulf Coast 3-2-1 crack (1)	US$/bbl	**13.45**	15.95	24.00	28.80	27.35	33.95	29.30	25.45
Exchange rate	US$/Cdn$	**0.95**	0.96	0.98	0.99	1.00	1.00	0.99	1.00
Exchange rate (end of period)	US$/Cdn$	**0.94**	0.97	0.95	0.98	1.01	1.02	0.98	1.00

(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 and cash flow from operations are driven primarily by production volumes, which can be significantly impacted by major maintenance events – such as the maintenance that occurred at Upgrader 1 in Oil Sands in the second quarter of 2013 and the maintenance that occurred at Terra Nova in the fourth quarter of 2013 and at many Exploration and Production assets in the third and fourth quarters of 2012, as well as third-party outages that impacted Oil Sands in the second, third and fourth quarters of 2013.

Trends in Suncor's quarterly earnings and cash flow from operations are also affected by changes in commodity prices, refining crack spreads and foreign exchange rates, as described in the Financial Information – Business Environment – Economic Sensitivities section of this MD&A.

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:

- The fourth quarter of 2013 included after-tax impairment charges of $563 million in the Exploration and Production segment against its assets in Syria, Libya and North America Onshore. Concurrent with the impairment of its Syrian assets, the company recognized after-tax risk mitigation proceeds of $223 million, previously recorded as a long-term provision.

- The first and fourth quarters of 2013 included a net after-tax charge of $58 million as a result of not proceeding with the Voyageur upgrader project, which included costs related to decommissioning and restoration of the Voyageur site and contract cancellations.

- The third quarter of 2013 included an after-tax gain of $130 million relating to the sale of the company's conventional natural gas business.

- The fourth quarter of 2012 included an after-tax impairment charge of $1.487 billion relating to the Voyageur upgrader project. Given Suncor's view of the challenging economic environment, the company performed an impairment test based on an assessment of expected future net cash flows.

- The fourth quarter of 2012 included an after-tax impairment reversal of $177 million of the impairment charges recorded against the company's 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 $172 million for certain exploration, development and production assets in the Exploration and Production segment, and a provision in North America Onshore for estimated future commitments relating to unutilized pipeline capacity.

- 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.

7. CAPITAL INVESTMENT UPDATE

The Capital Investment Update section contains forward-looking information. See the Advisories – 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)	**2013**	2012	2011
Oil Sands	**4 311**	4 957	5 100
Exploration and Production	**1 483**	1 261	874
Refining and Marketing	**890**	644	633
Corporate, Energy Trading and Eliminations	**93**	95	243
Total	**6 777**	6 957	6 850
Less: capitalized interest on debt	**(397)**	(587)	(559)
	6 380	6 370	6 291

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

Year ended December 31, 2013 ($ millions)	Sustaining	Growth	**Total**
Oil Sands	2 729	1 267	**3 996**
Oil Sands Base	*1 516*	*71*	***1 587***
In Situ	*814*	*381*	***1 195***
Oil Sands Ventures	*399*	*815*	***1 214***
Exploration and Production	151	1 250	**1 401**
Refining and Marketing	770	120	**890**
Corporate, Energy Trading and Eliminations	75	18	**93**
	3 725	2 655	**6 380**

(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 and logistics that are 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 2013, Suncor spent $6.380 billion on capital for property, plant and equipment and exploration activities, and capitalized $397 million of interest on debt towards major development assets and construction projects. Activity in 2013 included the following:

Oil Sands Base

Oil Sands Base capital expenditures were $1.587 billion, of which $1.516 billion was directed towards sustaining activities. Sustaining capital expenditures related primarily to planned maintenance events, including the Upgrader 1 turnaround completed in the second quarter of 2013 and planned maintenance of the Upgrader 2 vacuum tower and related units completed in the third and fourth quarters of 2013. Suncor continued to progress reliability and sustainment projects, including the construction of assets to support the TRO$_{TM}$ process and activities aimed at reducing freshwater use, including the construction of a water treatment plant.

Oil Sands Base growth capital focused on infrastructure required to support growth in production from Oil Sands Operations, including the commissioning of two new storage tanks in Hardisty, Alberta connected to the Enbridge mainline system. Growth capital was also directed towards debottlenecking projects, including a recently completed project in secondary extraction that has increased operational flexibility.

In Situ

In Situ capital and exploration expenditures were $1.195 billion, of which $381 million was directed towards growth projects. Growth capital in 2013 was focused on well pad development which contributed to the completion of the Firebag 4 ramp up in the fourth quarter of 2013. The company commissioned the hot bitumen infrastructure, including an insulated pipeline to flow hot bitumen from the Firebag site to Suncor's Athabasca terminal for cooling and blending with internal and imported third-party diluent. To support this infrastructure, the company entered into a finance lease for interconnects and additional tankage. The company's growth capital was also focused on debottlenecking projects at MacKay River, including a project that is intended to increase production capacity of the MacKay River facility by approximately 20% for a total capacity of 38,000 bbls/d by the end of 2015.

Sustaining capital expenditures of $814 million were directed towards ongoing design, engineering, procurement and construction of well pads that are expected to maintain existing production levels at Firebag and MacKay River in future years. The company expects to start steaming a well pad at MacKay River in the second quarter of 2014. Capital expenditures were also directed towards the infill well program at Firebag.

Oil Sands Ventures

Oil Sands Ventures growth capital expenditures were $815 million in 2013. The Fort Hills mining project expenditures were directed towards design engineering, site preparation and procurement of long-lead items.

On October 30, 2013, Suncor announced that the project co-owners had voted unanimously to proceed with the Fort Hills mining project. Suncor has a 40.8% interest and is the operator of the project.

Suncor and the co-owners of the Joslyn mining project continue to focus on design engineering and regulatory work.

Suncor's share of capital expenditures for the Syncrude joint operation in 2013 was $399 million, which included the completion of two mine train relocations at the Aurora mining area which started operating in July and October 2013, respectively. Capital expenditures were also focused on the mine train replacement at the Mildred Lake mining area and the construction of a centrifuge plant.

Growth capital also included the construction of midstream assets that are currently being used to support production in Oil Sands Operations, including hot bitumen cooling and blending, and related storage assets.

Exploration and Production

Exploration and Production capital and exploration expenditures were $1.401 billion in 2013, of which $1.250 billion was directed towards growth and exploration.

Growth spending included $190 million for Golden Eagle, which focused on the installation of two platform jackets, the wellhead topside, and subsea infrastructure. Growth spending for Hebron was $517 million in 2013, which focused on detailed engineering and construction of the gravity-based structure and topsides.

Growth spending of approximately $263 million focused on advancing extension projects which leverage existing facilities and infrastructure at East Coast Canada. Detailed engineering and subsea installation activities were completed in 2013 for the HSEU and subsea drilling activities commenced in early 2014. For the SWRX project, detailed engineering and procurement activities progressed while subsea installation activities commenced in 2013.

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.

During 2013, Suncor participated in the Butch East appraisal well offshore Norway. Drilling and evaluation of the Butch East well will continue into 2014, with drilling for a second appraisal scheduled for the middle of 2014. The company also completed the drilling and evaluation of the Romeo exploration well, and participated in the Scotney and Lily exploration wells in the U.K. sector of the North Sea – which were all deemed to be dry holes and charged to exploration expense in 2013.

The company continued to progress its exploration drilling program in Libya and drilled six exploration wells in 2013. Three of the six wells were assessed as dry holes and charged to exploration expense in 2013.

Sustaining capital expenditures focused primarily on the planned maintenance programs for East Coast Canada assets.

Refining and Marketing

Refining and Marketing spent $890 million on capital expenditures in 2013, largely focused on planned maintenance at the Edmonton, Sarnia and Montreal refineries. Growth spending was also directed towards projects to enhance integration with the company's Oil Sands operations, including early engineering and design work for facilities to prepare the Montreal refinery for the receipt and processing of inland crudes. Construction of a rail offloading facility to enable rail receipt of inland crudes to the Montreal refinery was completed in the fourth quarter of 2013.

Significant Growth Projects Update[1]

At December 31, 2013	Working Interest (%)	Description	Cost Estimate ($ millions)	Project Spend to date ($ millions)	Expected First Oil Date[3]
Operated					
Fort Hills	40.80	73.4 mbbls/d (net)	5 500	115	Q4 2017
Non-operated[2]					
Golden Eagle	26.69	18.7 mboe/d (net)	1 000 (+/-10%)	470	Q4 2014/ Q1 2015
Hebron	22.73	34.2 mboe/d (net)	2 800 (+/-10%)	517	Q4 2017

(1) Cost Estimate and Project Spend to date figures reflect post-sanction estimates and expenditures.

(2) Cost estimates are based on the most recent estimate provided by the operator.

(3) Expenditures to complete the project may extend beyond the first oil date.

The table above provides a review and update at December 31, 2013 of major growth projects that have been sanctioned for development by the company. Other growth projects, such as the Joslyn North oil sands mining project and the MacKay River expansion, have not yet received a final investment decision by the company or its Board of Directors and the respective co-owners, in the case of the Joslyn mining project.

The Fort Hills mining project will be developed using traditional open-pit truck and shovel techniques, and solvent-based extraction technology that will allow the mine to produce a marketable bitumen product. The project is scheduled to produce first oil in the fourth quarter of 2017 and achieve 90% of its planned gross production capacity of 180,000 bbls/d within twelve months. Project activity in 2014 includes the detailed engineering, procurement and ramp up of field construction activities. Suncor's share of the estimated post-sanction project cost is $5.5 billion, of which total expenditures incurred since project sanction are $115 million.

The field development plan for Golden Eagle includes stand-alone facilities designed for 70,000 boe/d of gross production. Activity in 2014 will focus on achieving first oil by late 2014 or early 2015, including installation of the production, utility and quarters platform, and development drilling. Total project expenditures to date are $470 million, with Suncor's share of the post-sanction project cost estimate being $1 billion.

The co-owners for the Hebron project 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. Project activity in 2014 is expected to focus on detailed engineering and construction of the gravity-based post-sanction structure and topsides. Suncor's share of the estimated project cost is $2.8 billion, of which Suncor's share of total project expenditures since sanction is $517 million.

Other Capital Projects

Suncor also anticipates 2014 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 and focusing on low-cost debottlenecking and expansion projects. These projects will be less capital intensive, but are expected to result in high returns and efficiencies throughout the Oil Sands operations. Suncor continues to work towards a 2014 sanction decision of the MacKay River expansion project, which is targeted to have an initial design capacity of approximately 20,000 bbls/d and first oil expected in 2017. The company also expects to substantially complete the Mackay River facility debottleneck in 2014, which is intended to increase production capacity by approximately 20% for a total capacity of 38,000 bbls/d by the end of 2015. Suncor plans to focus on validating all other debottlenecking initiatives of logistics infrastructure and Firebag facilities.

Sustaining capital includes planned maintenance but to a lesser degree than previous years as there is no major turnaround planned until 2016. Sustaining capital in 2014 continues to focus on the construction of assets to support the TRO$_{TM}$ process and activities aimed at reducing freshwater use, including the construction of a water treatment plant, which is expected to be commissioned in early 2014.

Suncor plans to focus on the completion of the well pads that are intended to offset natural production declines in Firebag and Mackay River. The company also plans to progress infill drilling programs at Firebag.

Oil Sands Ventures

Capital expenditures in 2014 for Syncrude are expected to focus on completing the mine train replacement for the Mildred Lake mining area and progress the tailings management program, including the construction of a centrifuge plant.

Suncor and the co-owners of the Joslyn mining project continue to focus on design engineering and regulatory work, and plan to provide an update on the targeted timing for a project sanction decision when available.

Exploration and Production

The company has multiple field extension projects underway which leverage existing facilities and infrastructure.

Subsea drilling commenced for the HSEU in early 2014. Overall production increases from the Hibernia field are expected to begin in 2015. For the SWRX, detailed engineering and procurement activities are expected to continue and subsea installation is planned for completion in late 2014. First oil is expected in late 2014 or early 2015. A sanction decision for further expansion into the western portion of the White Rose field is targeted for the second half of 2014. The current project plan consists of a wellhead platform, including a concrete gravity structure with topsides, drilling facilities and support services that will tie back into the existing White Rose FPSO for processing, storage and offloading.

In the North Sea, the company plans to continue evaluating the operated Beta prospect and plans to commence further appraisal drilling in 2014. In addition, the company plans to participate in four non-operated exploration wells in 2014. With respect to the non-operated Butch licence, drilling and evaluation activities of the Butch East well are expected to be complete in the first half of 2014 with plans for a second exploration well in mid-2014. Suncor continues to evaluate further exploration opportunities for its remaining licences, including four newly acquired licences in Norway, where Suncor is the operator on two of the licences. Exploration activity on the new licences will primarily involve acquisition or processing of seismic data, some of which will commence in 2014.

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 and process heavier crudes, including integration with the company's Oil Sands operations.

Renewable Energy

Growth capital will be focused on progressing projects within the company's renewable business. The Adelaide project received regulatory approval in December 2013 and has an expected completion date of late 2014. The Cedar Point project will continue to progress through the regulatory process in 2014. The two projects, based in Ontario, are expected to add 140 MW of gross installed capacity, increasing the gross installed capacity of Suncor's wind projects by 55%.

8. FINANCIAL CONDITION AND LIQUIDITY

Indicators

At December 31 ($ millions, except as noted)	2013	2012	2011
Return on Capital Employed (%)[1][2]			
Excluding major projects in progress	**11.5**	7.2	13.8
Including major projects in progress	**9.9**	5.8	10.1
Net debt to cash flow from operations[2] (times)	**0.7**	0.7	0.7
Interest coverage on long-term debt (times)			
Earnings basis[3]	**9.5**	7.9	10.7
Cash flow from operations basis[2][4]	**16.8**	17.7	16.4

(1) Non-GAAP financial measure. ROCE is reconciled in the Advisories – Non-GAAP Financial Measures section of this MD&A.

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

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

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

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 2014 capital spending program of $7.8 billion and meet 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.

The company has invested excess cash in short-term financial instruments that are presented as cash and cash equivalents on the Consolidated Balance Sheets. 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 does not exceed six months, and all investments are with counterparties with investment grade debt ratings.

Available Sources of Liquidity

Cash and Cash Equivalents

Cash and cash equivalents increased by $817 million to $5.202 billion during 2013.

As at December 31, 2013, the weighted average term to maturity of the short-term investment portfolio was approximately 57 days. In 2013, the company earned approximately $26 million of interest income on this portfolio.

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 2013 was $703 million, compared to $640 million in 2012. The increase in interest expense relates to new finance leases in 2013, partially offset by the repayment of debentures in 2013.

Unutilized lines of credit at December 31, 2013 were $4.536 billion, compared to $4.735 billion at December 31, 2012.

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

At December 31, 2013 ($ millions)	
Fully revolving for a period of one year after term-out date (November 2014)	2 000
Fully revolving and expires in 2015	900
Fully revolving for a period of three years and expires in 2016	3 000
Can be terminated at any time at the option of the lenders	288
Total available credit facilities	6 188
Less:	
Credit facilities supporting outstanding commercial paper	798
Credit facilities supporting standby letters of credit	854
Total unutilized credit facilities	4 536

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 65% of its total debt plus shareholders' equity. At December 31, 2013, total debt to total debt plus shareholders' equity was 22% (December 31, 2012 – 22%). The company is also currently in compliance with all operating covenants.

At December 31 ($ millions, except as noted)	**2013**	2012
Short-term debt	**798**	775
Current portion of long-term debt	**457**	311
Long-term debt	**10 203**	9 938
Total debt	**11 458**	11 024
Less: Cash and cash equivalents	**5 202**	4 385
Net debt	**6 256**	6 639
Shareholders' equity	**41 180**	39 215
Total debt plus shareholders' equity	**52 638**	50 239
Total debt to total debt plus shareholders' equity (%)	**22**	22

Change in Net Debt

($ millions)	
Net debt – December 31, 2012	6 639
Decrease in net debt	(383)
Net debt – December 31, 2013	6 256
Decrease in net debt	
Cash flow from operations	9 412
Capital and exploration expenditures and other investments	(6 795)
Acquisition	(515)
Proceeds from divestitures	943

Divestiture of pipeline contract	(76)
Dividends less proceeds from exercise of share options	(983)
Repurchase of common shares	(1 675)
Change in non-cash working capital	598
Foreign exchange on cash, debt and other balances	(526)
	383

At December 31, 2013, Suncor's net debt was $6.256 billion, compared to $6.639 billion at December 31, 2012. During 2013, net debt decreased by $383 million, largely due to cash flow from operations that exceeded capital and exploration expenditures, proceeds from the sale of the conventional natural gas business, partially offset by cash returned to shareholders in the form of share repurchases and dividends, the acquisition of Total E&P's interest in VULP and the impact of the weakening Canadian dollar relative to the U.S. dollar on the valuation of U.S. denominated debt.

For the year ended December 31, 2013, 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.

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 Investors Service	Baa1	Stable

The company's commercial paper ratings are:

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

Refer to the Description of Capital Structure – Credit Ratings section of Suncor's 2013 AIF for a description of credit ratings listed above.

Common Shares

Outstanding Shares

December 31, 2013 (thousands)	
Common shares	1 478 315
Common share options – exercisable and non-exercisable	34 997
Common share options – exercisable	27 104

As at February 24, 2014, the total number of common shares outstanding was 1,471,044,559, and the total number of exercisable and non-exercisable common share options outstanding was 38,992,223. Once exercisable, each outstanding common share option is convertible into one common share.

Share Repurchases

In the third quarter of 2012, the company obtained regulatory approval for a Normal Course Issuer Bid (the 2012 NCIB) with the Toronto Stock Exchange (TSX), authorizing the purchase for cancellation of up to $1 billion of Suncor's common shares, commencing September 20, 2012 and ending on September 19, 2013. On April 29, 2013, Suncor received regulatory approval to amend its 2012 NCIB, authorizing the purchase for cancellation of up to an additional $2 billion worth of its common shares, commencing May 2, 2013 and ending September 19, 2013.

Subsequently, on August 5, 2013, Suncor cancelled the 2012 NCIB and commenced a new normal course issuer bid (the 2013 NCIB) through the facilities of the Toronto Stock Exchange, New York Stock Exchange and/or alternative trading platforms. The 2013 NCIB was amended effective on February 21, 2014, to permit the company to purchase for cancellation additional shares. Pursuant to the 2013 NCIB, Suncor is permitted to purchase for cancellation up to approximately $2.8 billion worth of its common shares between August 5, 2013 and August 4, 2014, and has agreed that it will not purchase more than 111,121,897 common shares, which equals approximately 7.4% of the issued and outstanding common shares in the public float as at July 29, 2013.

Shareholders may obtain a copy of the company's Notice of Intention to make a Normal Course Issuer Bid in relation to both the 2012 NCIB and the 2013 NCIB, without charge, by contacting Investor Relations.

Under the 2012 NCIB, the company repurchased 25,075,100 common shares during 2013 at an average price of $31.17 per share, for a total repurchase cost of $781 million. Under the 2013 NCIB and as at December 31, 2013, the company repurchased 24,417,157 common shares during 2013 at an average price of $36.59 per share, for a total repurchase cost of $894 million.

Subsequent to December 31, 2013, the company has repurchased an additional 8,771,116 shares under the 2013 NCIB at an average price of $36.72 per share, for a total repurchase cost of $322 million, as of February 24, 2013.

At December 31 ($ millions, except as noted)	2013	2012
Share repurchase activities (thousands of common shares)		
Shares repurchased directly	**49 492**	46 862
Shares repurchased through exercise of put options	**—**	—
	49 492	46 862
Share repurchase cost ($ millions)		
Repurchase cost	**1 675**	1 452
Option premiums received	**—**	(1)
	1 675	1 451
Weighted average repurchase price per share, net of option premiums (dollars per share)	**33.84**	30.96

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

In addition to the enforceable and legally binding obligations in the table 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 the purchase of commodities for which an active, highly liquid market exists, and which are expected to be re-sold shortly after purchase.

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

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)	2014	2015 to 2016	2017 to 2018	Thereafter	Total
Fixed and revolving term debt[1]	**1 849**	**1 180**	**3 848**	**13 524**	**20 401**
Finance lease obligations	**110**	**222**	**216**	**2 222**	**2 770**
Decommissioning and restoration costs[2]	**334**	**740**	**584**	**6 373**	**8 031**
Operating lease agreements, pipeline capacity and energy services commitments	**1 721**	**2 411**	**2 019**	**6 989**	**13 140**
Exploration work commitments	**165**	**405**	**—**	**2**	**572**
Other long-term obligations[3]	**294**	**64**	**—**	**—**	**358**
Total	**4 473**	**5 022**	**6 667**	**29 110**	**45 272**

(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 Other Long-Term Liabilities note to the audited Consolidated Financial Statements.

(4) The company has also entered into various pipeline commitments which are awaiting regulatory approval. In the event regulatory approval is not obtained, Suncor has committed to reimbursing certain costs to the service provider.

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 note 31 to the 2013 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, 2013, the pre-tax earnings impact for risk management activities was a loss of $18 million (2012 – pre-tax gain of $1 million).

The company's Energy Trading business uses crude oil, natural gas, refined products and other derivative contracts to generate net earnings. For the year ended December 31, 2013, the pre-tax earnings impact for Energy Trading activities was a gain of $176 million (2012 – pre-tax gain of $246 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, 2012	—	(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)
Fair value of contracts realized during the year	18	(271)	(253)
Changes in fair value during the year	(18)	176	158
Fair value of contracts, outstanding – December 31, 2013	(1)	(138)	(139)

The fair value of derivative contracts are recorded in the Consolidated Balance Sheets.

Fair value of derivative contracts at December 31 ($ millions)	2013	2012
Accounts receivable	**225**	53
Accounts payable	**(364)**	(97)
	(139)	(44)

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 2013 audited Consolidated Financial Statements.

9. ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

Changes in Accounting Policies

Suncor's significant accounting policies are described in notes 3 to the audited Consolidated Financial Statements for the year ended December 31, 2013.

Effective January 1, 2013, the company adopted IFRS 10 *Consolidated Financial Statements*, IFRS 11 *Joint Arrangements*, IFRS 12 *Disclosures of Interests in Other Entities* and IFRS 13 *Fair Value Measurement*, and amendments to International Accounting Standard (IAS) 19 *Employee Benefits*, IFRS 7 *Financial Instruments: Disclosure* and IAS 36 *Impairment of Assets*.

Scope of a Reporting Entity

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, where sufficient rights and obligations are passed to the partners. 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.

The company identified two existing joint arrangements in the Refining and Marketing segment that have been retrospectively reclassified as joint ventures as a result of IFRS 11, and are now being accounted for using the equity method of accounting rather than the proportionate consolidation method. This change does not have a material impact to the Consolidated Financial Statements, but does result in the netting of revenues and expenses for these entities into Other Income. Cash flow from operations from these joint arrangements is now recognized based on cash distributions received in the period, where previously it was recognized based on the company's proportionate share of cash flow from operations. In addition, the company's net investment in these entities is now presented in Other Assets. The company determined that the adoption of IFRS 10 did not result in changes to the consolidation conclusions of any of its subsidiaries and investees. See note 29 for additional disclosures regarding the company's interest in associates and joint arrangements as a result of adopting IFRS 12.

Employee Benefits

The revised standard resulted in changes to the calculation and presentation of pension interest cost, which is now calculated on the net unfunded obligation, applying the discount rate used to measure the employee benefit obligation at the beginning of the annual period. Previously, pension interest cost was net of interest income on plan assets (using the expected return on plan assets) and interest expense on the plan obligation (using the discount rate). The net pension interest expense was reclassified to Financing Expenses from Operating, Selling and General expense. The change to the pension interest cost calculation also resulted in the refundable tax accounts (RTA) being present valued, resulting in an immaterial adjustment to the Consolidated Balance Sheets.

Fair Value Measurements

IFRS 13 establishes a single source of guidance for most fair value measurements, clarifies the definition of fair value, and enhances the disclosures on fair value measurements. The adoption of IFRS 13 did not require any adjustments to the valuation techniques used by the company to measure fair value and did not result in any fair value measurement adjustments as at January 1, 2013. The adoption of this standard resulted in additional disclosures regarding the fair value measurement of the company's financial instruments. See note 27 to the audited Consolidated Financial Statements for the year ended December 31, 2013.

Offsetting Financial Assets and Liabilities

The amendments to IFRS 7 clarify the offsetting model and develop common disclosure requirements to enhance the understanding of the potential effects of offsetting arrangements. The adoption of this amendment resulted in additional disclosure for the company's offsetting financial assets and financial liabilities. See note 27 to the audited Consolidated Financial Statements for the year ended December 31, 2013.

Recoverable Amount Disclosures for Non-Financial Assets

The company early adopted amendments to IAS 36 *Impairment of Assets*. The amendments clarified the recoverable amount is disclosed only when an asset or cash generating unit is impaired. The adoption of this amended standard also resulted in expanded disclosure for recoverable amounts of impaired assets that are calculated based on fair value less costs of disposal methodology and for cash-generating units with goodwill that are not impaired, including the disclosure of the fair value

measurement level input. See note 27 to the audited Consolidated Financial Statements for the year ended December 31, 2013.

The effects of the application of IFRS 11 and the IAS 19 amendment to consolidated net earnings, operating earnings and cash flow from operations for the twelve months ended December 31, 2012 are shown in the table below and reflect the application of relevant transitional provisions.

($ millions)	Year ended December 31, 2012
Net earnings before accounting changes	**2 783**
Adjustments to net earnings:	
Recognition of interest costs on net unfunded obligation (IAS 19)	**(43)**
Net earnings after accounting changes	**2 740**
Operating earnings before accounting changes	**4 890**
Adjustments to operating earnings:	
Recognition of interest costs on net unfunded obligation (IAS 19)	**(43)**
Operating earnings after accounting changes	**4 847**
Cash flow from operations before accounting changes	**9 745**
Adjustments to cash flow from operations:	
Proportionate consolidation to equity accounting (IFRS 11)	**(5)**
Recognition of interest costs on net unfunded obligation (IAS 19)	**(7)**
Cash flow from operations after accounting changes	**9 733**

Recently Announced Accounting Standards

The standards and interpretations that are issued but not yet effective up to the date of issuance of the company's financial statements, and may have an impact on the disclosures and financial position of the company, are disclosed below. The company intends to adopt these standards and interpretations, if applicable, when they become effective.

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IAS 32 *Financial Instruments: Presentation* to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event. Retrospective application of amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014 with earlier application permitted. The adoption of this amended standard is not expected to have a material impact on the company's financial statements.

Levies

In May 2013, the IASB issued International Financial Reporting Interpretation Committee (IFRIC) 21 *Levies*. This clarifies that an entity recognizes a liability for a levy when the activity that triggers payment occurs.

For a levy that is triggered upon reaching a minimum threshold, the interpretation clarifies that no liability should be anticipated before the minimum threshold is reached. Retrospective application of this interpretation is effective for annual periods beginning on or after January 1, 2014, with earlier application permitted. The company is assessing the impact of this interpretation on royalties and property taxes.

Financial Instruments: Recognition and Measurement

In November 2009, as part of the IASB project to replace 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. In November 2013, the IASB issued amendments to include the new general hedge accounting model and to postpone the mandatory effective date of this standard indefinitely. The full impact of this standard will not be known until the amendments addressing impairments, classification and measurement have been completed. When these projects are completed, an effective date will be added by the IASB.

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 judgments 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 judgments are those judgments made by management in the process of applying the company's accounting policies and that have the most significant impact on the amounts recognized in the Consolidated Financial Statements.

Critical accounting estimates and judgments 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, 2013 audited Consolidated Financial Statements.

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. The reserves and resources estimates are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook and are reviewed on an annual basis by qualified reserves evaluators in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* .

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, 2013, 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 (CGU)

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 of disposal 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.

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 2013, the company completed this review as at October 31, 2013, and determined that the underlying CGUs were not impaired.

The following significant impairment assessments were completed during 2013:

Syria

Since December 2011, Suncor's operations in Syria and its contractual obligations have been suspended under a period of force majeure due to political unrest and international sanctions. The company impaired the remaining carrying value of its Syrian assets, resulting in an after-tax impairment charge of $422 million in the fourth quarter of 2013, under management's view that the ongoing political situation has led to increasing uncertainty with respect to the company's return to operations in the country.

The company received risk mitigation proceeds in the fourth quarter of 2012, at which time the proceeds were recorded as a non-current provision to reflect potential repayment if operations in Syria were to resume. Suncor recognized the risk mitigation proceeds of $300 million ($223 million after-tax) in net earnings in the fourth quarter of 2013, as the likelihood of return in the foreseeable future is undeterminable.

Libya

Recent political unrest has resulted in the closure of export terminal operations at eastern Libyan seaports, requiring the shut-in of production for the latter half of 2013. As the situation persisted at the end of 2013, management performed an impairment test at December 31, 2013.

The impairment test was performed based on an assessment of future net cash flows over a range of possible outcomes, resulting in an after-tax impairment charge of $101 million in the fourth quarter of 2013.

The carrying value of the company's net assets in Libya as at December 31, 2013 was approximately $570 million.

The carrying value as at December 31, 2013 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) future cash flows assuming the development of the company's proved plus probable reserves evaluated as at December 31, 2013, ii) future cash flows incorporating additional growth in accordance with managements strategic growth plans, and iii) suspension of all activity at the end of 2014. The first two scenarios were equally weighted at 45% each and the final scenario was assigned a weighting of 10% based on the company's best estimates. All scenarios assumed the restart of production on April 1, 2014.

The estimates used in calculating the net recoverable amounts were based on 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, and a discount rate of 17% that represented management's best estimate of the ongoing risk involved with operating in Libya.

Fort Hills

On October 30, 2013, the co-owners of Fort Hills announced project sanction. As a result, the accumulated capital costs in Exploration and Evaluation were transferred to oil and gas properties in Property, Plant and Equipment and an impairment test was required in accordance with IFRS 6 Exploration for and Evaluation of Mineral Resources. A fair value less costs of disposal methodology was used to determine the recoverable amount and, as it exceeded the carrying amount, no impairment was recorded.

The significant estimates used in calculating the net recoverable amounts included current forecasts for the price of bitumen, future capital costs and discount rate. The assumptions used by management to calculate the recoverable amount may change. Changes in these assumptions will have an impact on the recoverable amount and could result in impairment. Refer to note 17 of the Consolidated Financial Statements for further details.

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 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.

Suncor's provision for decommissioning and restoration costs decreased by $450 million in 2013 to $4.238 billion. The most significant change in the provision related to decommissioning and restoration liabilities related to the sale of the company's natural gas business, which was partially offset by increased disturbance in other areas of the company's operations and increase in certain cost estimates. The provision also decreased due to an increase

in the average credit-adjusted discount rate (2013 – 4.51%; 2012 – 3.75%).

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.

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.

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.

In December 2013, Suncor reached an agreement with the Government of Alberta concerning several outstanding issues under the RAA entered into in 2008. The impacts of the final settlements were not material to the company's results. The company is no longer recording a provision related to royalty disputes under the RAA.

The company is involved in litigation and claims in the normal course of operations. As at December 31, 2013, management believes the result of any settlements related to such litigation or claims would not materially affect the financial position of the company.

Income Taxes

Management evaluates tax positions, annually or when circumstances require, which involves judgment and could be subject to differing interpretations of applicable tax legislation. The company recognizes a tax provision when a payment to tax authorities is considered probable. However, the results of audits and reassessments and changes in the interpretations of standards may result in changes to those positions and potentially 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 certain derivative contracts. Following Suncor's response to a number of information requests in 2013, the CRA informed the company that it has not changed its original proposed position.

In the event that the CRA issues a formal Notice of Reassessment (NOR), Suncor plans to file a Notice of Objection to dispute this matter. However, notwithstanding the filing of an objection, 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.

Suncor strongly disagrees with the CRA's position and 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. If the company is unsuccessful in defending its tax filing position, it could be subject to an earnings impact of up to $1.2 billion.

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 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, estimates of the expected settlement amount, timing of reversals, 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.

Joint Arrangements

The classification of joint arrangements structured through separate vehicles as either joint ventures or joint operations requires significant judgment and depends on the legal form and contractual terms of the arrangement as well as other facts and circumstances. These include whether there is exclusive dependence on the parties to the joint arrangement for cash flows through the sale of product and funding of operations, and to assess the rights of the economic benefits of the assets and obligation for funding the liabilities of the arrangements. A joint arrangement whereby the parties take their share of substantially all of the output of the joint arrangement would be an indicator for classification as a joint operation, regardless of structure of the arrangement, and accounted for by recognizing the company's share of assets and liabilities jointly owned and incurred, and the recognition of its share of revenue and expenses of the joint operation.

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.

10. 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. Some of these risks are common to operations in the oil and gas industry as a whole, while some are unique to Suncor. The company's enterprise risk committee (ERC), comprised of senior representatives from business and functional groups across Suncor, oversees entity-wide processes to identify, assess and report on the company's principal risks. A principal risk is an exposure that has the potential to materially impact the ability of one of our businesses or functions to meet or support a Suncor objective. The realization of any of the following principle risk factors could have a material adverse effect on our business, financial condition, results of operations and cash flow:

Volatility of Commodity Prices

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 prices for all of these commodities can be influenced by global and regional supply and demand factors, which are factors that are beyond our control and can result in a high degree of price volatility

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.

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.

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. 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.

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 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, financial condition, results of operations and cash flow.

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.

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.

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.

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;
- The effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment; and
- Risk associated with offshore fabrication and logistics.

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.

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, and materially adversely affect Suncor's business, financial condition and results of operations, and may reduce cash flow available for growth or dividends and major project capital costs. This may 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.

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. Suncor positions itself to be ahead of proposed changes or engages in the discussion on proposed changes to ensure Suncor's interests are recognized.

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 the 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;
- Issues related to offset requirements for various land disturbances;
- 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 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 to $60 per tonne of carbon dioxide 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 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 the volumes of fluid fine 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 includes management frameworks for air, land, and water quality that incorporate cumulative limits and triggers. As well, the LARP identifies areas related to conservation, tourism and recreation.

A management framework for water quantity (water withdrawals from the Athabasca River) has recently been announced. A management framework for biodiversity is under development.

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, by the operators 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. Water licences, like all regulatory approvals, contain conditions to be met in order to maintain compliance with the licence. Although 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, without evidence of an environmental impact associated with the licence and providing compliance is maintained, this is not likely to occur. 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, although there is currently no evidence that governments are contemplating such a fee at this time. In addition, the expansion of the company's projects may rely on securing licences for additional water withdrawal, and there can be no assurance that these licences will be granted or that they will be granted on terms favourable to Suncor.

Income Taxes

In January 2013, the company received a proposal letter from the CRA relating to the income tax treatment of realized losses in 2007 on the settlement of certain derivative contracts. Following Suncor's response to a number of information requests in 2013, the CRA informed the company that it has not changed its original proposed position.

In the event that the CRA issues a formal Notice of Reassessment (NOR), Suncor plans to file a Notice of Objection to dispute this matter. However, notwithstanding the filing of an objection, 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.

Suncor strongly disagrees with the CRA's position and 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. If the company is unsuccessful in defending its tax filing position, it could be subject to an earnings impact of up to $1.2 billion.

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 also demand a large number of improvement initiatives that compete for resources, and may negatively impact the company should there be inadequate 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.

Other Risk Factors

A detailed discussion of additional risk factors is presented in our most recent Annual Information Form / Form 40-F, filed with securities regulators.

11. OTHER ITEMS

Control Environment

Based on their evaluation as of December 31, 2013, Suncor's Chief Executive Officer and Interim 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, 2013, 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, 2013 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 political unrest in Syria, Suncor is not able to monitor the status of the Syrian assets, including whether certain facilities have suffered damages. Suncor is continually assessing the control environment in Syria to the extent permitted by applicable law and does not consider the changes in the country 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, 2013 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, 2013.

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

Corporate Guidance

Detailed guidance on the company's outlook for 2014 production, capital expenditures and other items can be found in Suncor's press release dated February 3, 2014, available on www.sedar.com and on the Suncor website at www.suncor.com/guidance. The press release provides updates to the guidance that was previously issued on November 20, 2013.

12. ADVISORIES

Non-GAAP Financial Measures

Certain financial measures in this MD&A – namely operating earnings, ROCE, cash flow from operations, free cash flow, Oil Sands cash operating costs and LIFO – 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.

Effective January 1, 2013, Suncor adopted new and amended accounting standards; as such, non-GAAP measures for 2012 have been restated while comparative figures pertaining to Suncor's results prior to and including 2011 have not been restated in accordance with the respective transitional provisions of the new and amended standards.

Non-GAAP measures for 2009 are reported under a previous GAAP.

Operating Earnings

Operating earnings is a non-GAAP financial measure that adjusts net earnings for significant items that are not indicative of operating performance. Management uses operating earnings to evaluate operating performance, because management believes it provides better comparability between periods. Operating earnings are reconciled to net earnings in the Financial Information section 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 have been adjusted from operating earnings previously reported to include the effect of project start-up costs and mark-to-market valuations of stock-based compensation, which were previously excluded when calculating operating earnings.

($ millions)	**2013**	2012	2011	2010	2009
Net earnings as reported	**3 911**	2 740	4 304	3 829	1 146
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**521**	(157)	161	(372)	(798)
Impairments and write-offs, net of reversals	**563**	2 176	629	306	42
Recognition of risk mitigation proceeds	**(223)**	—	—	—	—
(Gain) loss on significant disposals	**(130)**	—	107	(826)	39
Net impact of not proceedings with the Voyageur upgrader project	**58**	—	—	—	—
Impact of income tax rate adjustment on deferred income taxes	**—**	88	442	—	4
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
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	**4 700**	4 847	5 674	2 634	1 115

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. These factors are analyzed in the Operating Earnings narratives following the bridge analyses in a particular section of the MD&A. These bridge analyses are presented because management uses this presentation to analyze performance.

- The factor for Volumes and Mix is calculated based on production volumes and mix for the Oil Sands and Exploration and Production segments and throughput volumes and mix 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, including product purchased for use as diluent in the company's Oil Sands operations and subsequently sold as part of diluted bitumen.

- The factor for Royalties includes royalties in Libya that represent the difference between gross revenues, which is based on the company's working-interest share of production, and the net revenue attributable to Suncor under the terms of the respective contracts.

- 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 and Mix based on production volumes, rather than based on sales volumes.

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

- The factor for Financing Expense and Other Income includes financing expenses, 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)		**2013**	2012	2011	2010	2009
Adjustments to net earnings						
Net earnings		**3 911**	2 740	4 304	3 829	1 146
Add after-tax amounts for:						
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt		**521**	(157)	161	(372)	(858)
Net interest expense		**228**	42	83	327	349
	A	**4 660**	2 625	4 548	3 784	637
Capital employed – beginning of twelve-month period						
Net debt		**6 639**	6 976	11 254	13 516	7 226
Shareholders' equity		**39 215**	38 592	35 192	32 485	14 523
	D	**45 854**	45 568	46 446	46 001	21 749
Capital employed – end of twelve-month period						
Net debt		**6 256**	6 639	6 976	11 254	13 377
Shareholders' equity		**41 180**	39 215	38 600	35 192	34 111
		47 436	45 854	45 576	46 446	47 488
Average capital employed	B	**46 981**	45 353	44 956	46 075	35 128
ROCE – including major projects in progress (%)	A/B	**9.9**	5.8	10.1	8.2	1.8
Average capitalized costs related to major projects in progress	C	**6 502**	8 729	12 106	12 890	10 655
ROCE – excluding major projects in progress (%)	A/(B-C)	**11.5**	7.2	13.8	11.4	2.6

Cash Flow from Operations and Free Cash Flow

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.

	Oil Sands			Exploration and Production			Refining and Marketing		
Year ended December 31 ($ millions)	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Net earnings (loss)	**2 040**	468	2 603	**1 000**	138	306	**2 022**	2 137	1 726
Adjustments for:									
Depreciation, depletion, amortization and impairment	**2 439**	3 964	1 374	**1 804**	1 857	2 035	**530**	464	444
Deferred income taxes	**358**	266	895	**(130)**	28	354	**64**	529	494
Accretion of liabilities	**114**	109	85	**60**	62	69	**6**	4	3
Unrealized foreign exchange (gain) loss on U.S. dollar denominated debt	**—**	—	—	**—**	—	—	**—**	—	—
Change in fair value of derivative contracts	**—**	—	—	**—**	—	—	**1**	(1)	3
(Gain) loss on disposal of assets	**—**	(29)	122	**(130)**	(1)	31	**(7)**	(13)	(16)
Share-based compensation	**7**	95	(35)	**28**	14	(4)	**19**	48	(21)
Exploration expenses	**—**	—	—	**82**	145	28	**—**	—	—
Settlement of decommissioning and restoration liabilities	**(388)**	(380)	(458)	**(15)**	(32)	(19)	**(20)**	(21)	(19)
Other	**(14)**	(86)	(14)	**(383)**	16	46	**3**	(9)	(40)
Cash flow from (used in) operations	**4 556**	4 407	4 572	**2 316**	2 227	2 846	**2 618**	3 138	2 574
Decrease (increase) in non-cash working capital	**1 225**	(781)	(676)	**656**	(205)	398	**566**	(460)	600
Cash flow provided by (used in) operating activities	**5 781**	3 626	3 896	**2 972**	2 022	3 244	**3 184**	2 678	3 174

Year ended December 31 ($ millions)	Corporate, Energy Trading and Eliminations 2013	2012	2011	Total 2013	2012	2011
Net (loss) earnings	**(1 151)**	(3)	(331)	**3 911**	2 740	4 304
Adjustments for:						
Depreciation, depletion, amortization and impairment	**119**	161	99	**4 892**	6 446	3 952
Deferred income taxes	**90**	(94)	(99)	**382**	729	1 644
Accretion of liabilities	**12**	7	—	**192**	182	157
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	**605**	(181)	183	**605**	(181)	183
Change in fair value of derivative contracts	**94**	11	(43)	**95**	10	(40)
Loss (gain) on disposal of assets	**—**	(1)	(1)	**(137)**	(44)	136
Share-based compensation	**160**	57	(42)	**214**	214	(102)
Exploration expenses	**—**	—	—	**82**	145	28
Settlement of decommissioning and restoration liabilities	**—**	—	—	**(423)**	(433)	(496)
Other	**(7)**	4	(12)	**(401)**	(75)	(20)
Cash flow (used in) from operations	**(78)**	(39)	(246)	**9 412**	9 733	9 746
Decrease (increase) in non-cash working capital	**(1 759)**	572	(80)	**688**	(874)	242
Cash flow (used in) provided by operating activities	**(1 837)**	533	(326)	**10 100**	8 859	9 988

The following is a reconciliation of cash flow from operations for Suncor's last five years of operations.

($ millions)	2013	2012	2011	2010	2009
Cash flow provided by operating activities	**10 100**	8 859	9 988	5 486	2 575
(Decrease) increase in non-cash working capital	**(688)**	874	(242)	1 170	224
Cash flow from operations	**9 412**	9 733	9 746	6 656	2 799

Free cash flow is a non-GAAP financial measure that is calculated by deducting capital and exploration expenditures from cash flow from operations. Free cash flow reflects cash available for distribution to shareholders and to fund financing activities. Management uses free cash flow to measure financial performance and liquidity. The following is a reconciliation of free cash flow for Suncor's last three years of operations.

($ millions)	2013	2012	2011
Cash flow from operations	**9 412**	9 733	9 746
Capital and exploration expenditures	**(6 777)**	(6 957)	(6 850)
Free Cash Flow	**2 635**	2 776	2 896

Oil Sands Cash Operating Costs

Oil Sands cash operating costs and cash operating costs per barrel are non-GAAP financial measures, which are calculated 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.

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 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
Cash operating costs, as previously reported	4 479
Elements added to cash operating costs definition:	
Safety programs	33
Elements removed from cash operating costs definition:	
Natural gas feedstock for secondary upgrading processes	(53)
Accretion of liabilities	(64)
Purchased diluent	(40)
Cash operating costs, as restated in this MD&A	4 355
Cash operating costs, as previously reported ($/bbl)	40.20
Cash operating costs, as restated in this MD&A ($/bbl)	39.05

Impact of First-in, First-out Inventory Valuation on Refining and Marketing Net Earnings

GAAP requires the use of a 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 products inventory levels.

Suncor prepares and presents an estimate of the impact of using a FIFO inventory valuation methodology compared to a 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).

The company's estimate is not derived from a standardized calculation and, therefore, may not be directly 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.

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.

Common Abbreviations

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

Measurement

bbl	barrel
bbls/d	barrels per day
mbbls/d	thousands of barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mboe/d	thousands of barrels of oil equivalent per day
mcf	thousands of cubic feet of natural gas
mcfe	thousands of cubic feet of natural gas equivalent
mmcf	millions of cubic feet of natural gas
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
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

Forward-Looking Information

The MD&A contains certain forward-looking statements within the meaning of applicable Canadian and U.S. Securities laws and other information based on Suncor's current expectations, estimates, projections and assumptions that were made by the company in light of information available at the time the statement was made and consider Suncor's experience and its perception of historical trends, including expectations and assumptions concerning: the accuracy of reserves and resources estimates; commodity prices and interest and foreign exchange rates; capital efficiencies and cost-savings; applicable royalty rates and tax laws; future production rates; the sufficiency of budgeted capital expenditures in carrying out planned activities; the availability and cost of labour and services; and the receipt, in a timely manner, of regulatory and third-party approvals. In addition, all other statements and other information that address expectations or projections about the future, and other statements and information about Suncor's strategy for growth, expected and future expenditures or investment decisions, commodity prices, costs, schedules, production volumes, operating and financial results, future financing and capital activities, and the expected impact of future commitments are forward-looking statements. Some of the forward-looking statements and information may be identified by words like "expects", "anticipates", "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:

- *An increase in capacity by 20% to 38,000 bbls/d by the end of 2015 at the MacKay River facility as a result of debottlenecking activities, which are expected to be substantially completed by 2014;*
- *Extension projects at Hibernia are expected to extend productive life and increase overall production starting in 2015;*
- *The expectation to start steaming a well pad at MacKay River in the second quarter of 2014; and*
- *Rail transport to Quebec is expected to increase to approximately 35,000 bbls/d in the first quarter of 2014.*

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

- *No major turnarounds planned at Oil Sands Operations until 2016. The company plans to complete routine maintenance on three coker units, in addition to seasonal maintenance throughout 2014 in Oil Sands Operations;*
- *Routine annual planned maintenance has been scheduled at Terra Nova and White Rose in the third quarter of 2014, and in the second and third quarters of 2014 at Buzzard; and*
- *Planned maintenance events at Commerce City refinery in the first quarter of 2014 with an expected duration of three weeks, a five-week maintenance in the second*

quarter of 2014 and an eight-week maintenance event beginning late in the third quarter of 2014 at the Montreal refinery, and a seven-week maintenance event in the second quarter of 2014 and a four-week maintenance event in the third quarter of 2014 at the Edmonton refinery.

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

- *The company's plans to advance a number of debottlenecking initiatives across Oil Sands Operations and expansions at In Situ which are expected to grow production at Oil Sands Operations sites to approximately 500,000 bbls/d by the end of 2018;*
- *A sanction decision for the MacKay River expansion project is expected for the second half of 2014, which is targeted to have an initial design capacity of approximately 20,000 bbls/d with first oil expected in 2017. Certain synergies of key processes and utility systems with the existing MacKay River facility are expected;*
- *Development drilling programs at both Firebag and MacKay River and infill drilling at Firebag are expected to be an area of focus in 2014 in support of steady production growth and sustainment;*
- *Projects such as the turnaround of Upgrader 1 in the second quarter of 2013 are expected to contribute to further reliability improvements;*
- *Suncor's portfolio of technology projects is expected to not only drive improvements and efficiencies in current production, but aid in developing future opportunities;*
- *Suncor plans to develop the Fort Hills mining area using traditional open-pit truck and shovel techniques, and solvent-based extraction technology that will allow the mine to produce a final marketable bitumen product. The project is expected to provide Suncor with approximately 73,000 bbls/d of bitumen, with first oil expected in the fourth quarter of 2017. Project activities in 2014 are expected to focus on detailed engineering, procurement and the ramp up of field construction activities;*
- *Plans to provide an update on the targeted timing of a sanction decision for the Joslyn mining area when available;*
- *The subsea installation for the SWRX project is planned for 2014, as well as completion of detailed engineering and procurement activities, with first oil expected in late 2014 or early 2015;*
- *Maintenance on Terra Nova completed in 2013 is expected to contribute to improved reliability in 2014;*
- *A sanction decision for further expansion in the western portion of the White Rose field is targeted for the second half of 2014;*
- *First oil at Hebron is expected in 2017 and detailed engineering and construction of the gravity-based structure and topsides will continue in 2014;*
- *Golden Eagle will achieve first oil in late 2014 or early 2015, with drilling operations expected to commence in early 2014;*
- *Plans to continue evaluating the operated Beta prospect and commence further appraisal drilling in 2014, in addition, the company plans to participate in four non-operated exploration wells 2014 in the North Sea;*
- *With respect to the non-operated Butch licence, drilling and evaluation activities of the Butch East well are expected to be complete in the first half of 2014 with plans for a second exploration well in mid-2014;*
- *Exploration activity on four new licences in Norway are expected to involve primarily acquisition or processing of seismic data, some of which will commence in 2014;*
- *The project to modify hydrocracking at the Montreal refinery is expected to improve energy efficiency and product yield by 2015 and contribute to the company's integration strategies;*
- *The company expects to complete the Adelaide wind project by the fourth quarter of 2014. The Cedar Point project continues to progress through the regulatory process. The two projects, based in Ontario, are expected to add 140 MW of gross installed capacity, increasing the gross installed capacity of Suncor's wind projects by 55%;*
- *Cost estimates, target completion dates and project details provided in the Capital Investment Update – Significant Growth Projects Update section of this MD&A;*
- *Plans in 2014 to focus on the construction of assets to support the TRO ™ process and activities aimed at reducing freshwater use, including the construction of a water treatment plant, which is expected to be commissioned in early 2014;*
- *Completion of well pads at Firebag and MacKay River are expected to offset natural production declines;*
- *Plans for Syncrude to focus on completing the mine train replacement for the Mildred Lake mining area and progress the tailings management program, including the construction of a centrifuge plant;*

- *HSEU is expected to provide overall production increases to the Hibernia field beginning in 2015;*

- *Exploration activity on the new licences in Norway will primarily involve acquisition or processing of seismic data, some of which is expected to commence in 2014; and*

- *Plans to focus on planned maintenance events and routine asset replacement in Refining and Marketing, and that growth capital is expected to be deployed on projects to prepare the Montreal refinery to receive and process heavier crudes, including integration with the company's Oil Sands operations.*

Also:

- *Suncor's projects in its growth portfolio are expected to provide long-term profitability to the company;*

- *Intermittent curtailments of natural gas supply are expected to continue through the first quarter of 2014 while the third-party operator completes its investigations and restoration activities;*

- *The company's assessment of the situation in Libya and Syria, including the amounts recorded as impairment charges and that formal extension agreements in relation to its EPSAs will follow later in 2014;*

- *Management's belief that Suncor will have the capital resources to fund its planned 2014 capital spending program of $7.8 billion and to meet 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; 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; 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, such as Suncor's current disagreement with the Canada Revenue Agency relating to the settlement of certain derivative contracts, including the risk that Suncor may not be able to successfully defend its original filing position if it is reassessed and ultimately be required to pay increased taxes as a result; changes in environmental and other regulations; the ability and willingness of parties with whom we have material relationships to perform their obligations to us; outages to third-party infrastructure that could cause disruptions to production; 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 2013 AIF dated February 28, 2014 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, 2013, dated February 28, 2014

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EXHIBIT 99-3

Consent of PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
111 5th Avenue SW,
Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 (403) 509 7500
Facsimile +1 (403) 781 1825

CONSENT OF INDEPENDENT AUDITOR

We hereby consent to inclusion in this Annual Report on Form 40-F for the year ended December 31, 2013 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 28, 2014 relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in the Annual Report.

We also consent to reference to us under the heading "Interests of Experts" in the Annual Information Form incorporated by reference in this Annual Report on Form 40-F which is incorporated by reference in the Registration Statements referred to above.

"PricewaterhouseCoopers LLP"
Chartered Accountants
Calgary, Alberta
February 28, 2014

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EXHIBIT 99-3

Consent of PricewaterhouseCoopers LLP

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EXHIBIT 99-4

Consent of GLJ Petroleum Consultants Ltd.

LETTER OF CONSENT

TO: Suncor Energy Inc.
The Securities and Exchange Commission
The Securities Regulatory Authorities of Each of the Provinces of Canada

Dear Sirs

Re: Suncor Energy Inc.

We refer to the following reports (the "**Reports**") prepared by GLJ Petroleum Consultants Ltd. ("**GLJ**"):

- Reserves Assessment and Evaluation of In Situ Oil Sands Properties — 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, 2013.

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, 2013 (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. 2013 Annual Report for the year ended December 31, 2013 (the "**Annual Report**") to be filed with the securities regulatory authorities of each of the provinces of Canada; and
3. Annual Information Form dated February 28, 2014 (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: February 28, 2014
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;
- Evaluation of the P&NG Reserves of Suncor Energy Inc. in the North America Onshore Properties;
- Update to the Assessment of P&NG Resources of Suncor Energy Inc. in the Montney Formation, Kobes Area, British Columbia ("Kobes Resource Assessment");
- Evaluation of the P&NG Reserves of Suncor Energy Inc., North Sea Properties;
- Evaluation of the P&NG Reserves of Suncor Energy Inc., Libya Properties, Volumes 1 & 2;
- Evaluation of the P&NG Reserves of Suncor Energy Inc., Other International Properties, Volume 3 — Ash Shaer Field, Syria ("Syria Reserves Assessment").

which provide our reports on proved and probable reserves evaluations and assessment of contingent resources 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, 2013, except in the case of: (i) the Kobes Resource Assessment, which is as at June 30, 2013; (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, 2013 (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. 2013 Annual Report for the year ended December 31, 2013 (the " **Annual Report**") to be filed with the securities regulatory authorities of each of the provinces of Canada; and

3. Annual Information Form dated February 28, 2014 (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, FEC, FGC (Hon.)
President & Chief Operating Officer and Director

Dated: February 28, 2014
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: February 28, 2014

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EXHIBIT 99-6

CERTIFICATION

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EXHIBIT 99-7

CERTIFICATION

I, Steven D.L. Reynish, 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 annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this 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 D.L. REYNISH

Steven D.L. Reynish
Interim Chief Financial Officer

DATE: February 28, 2014

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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, 2013 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: February 28, 2014

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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, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, STEVEN D.L. REYNISH, Interim 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/ STEVEN D.L. REYNISH

Steven D.L. Reynish
Interim Chief Financial Officer
Suncor Energy Inc.

DATE: February 28, 2014

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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