SUNCOR ENERGY INC
Form 40-F
February 28, 2014

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

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$_{TM}$) 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 tonne = 0.984 tons (long)
1 m^3 natural gas = 35.49 cubic feet	1 tonne = 1.102 tons (short)
1 m^3 overburden = 1.31 cubic yards	1 kilometre = 0.62 miles
	1 hectare = 2.5 acres

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

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

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 6th Avenue S.W., Calgary, Alberta, T2P 3E3.

Intercorporate Relationships

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

<u>MacKay River</u>

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.

Sales Volumes and Operating Revenues	Principal Products	**2013** mbbls/d	**2013** % operating revenues	2012 mbbls/d	2012 % 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

<u>Oil Sands Base and Syncrude</u>

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.

<u>In Situ</u>

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.

<u>Terra Nova</u>

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:

	2013		2012	
Sales Volumes	mboe/d	% operating revenues	mboe/d	% 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	Montreal		Sarnia		Edmonton		Commerce City	
(mbbls/d, except as noted)	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 2013	Montreal 2012	Sarnia 2013	Sarnia 2012	Edmonton 2013	Edmonton 2012	Commerce City 2013	Commerce City 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				&								